Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

August 19th - 20th, 2015

Magnolia Hotel, Denver, CO

• SUMMARY OF ACTIONS TAKEN •

1. Approved the changes embodied in the posted RR56.
2. Approved the 2015 Regional Review Model.
3. Approved incremental solar capacity assumptions for all Futures.
4. Accepted Staff's method to produce a list of potential retirements [to be utilized in the development of Future 1 and Future 2], including the assumed carbon price, that will be reviewed for individual unit rejection by the stakeholders.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

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• 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 26 in person attendees and 41 web conference participants representing 12 of 12 ESWG members. (Attachment 1 – August 19-20, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. Three proxies were identified; Bennie Weeks (SPS) named Bill Grant (Xcel Energy) as her proxy, Don Le (NextEra) named Noman Williams (South Central MCN) as his proxy, Kip Fox (AEP-Transource) named Wayman Smith (AEP) as his proxy. (Attachment 2 – Proxy Statements)

Following receipt of proxies, additional proxies were identified. Noman Williams (South Central MCN) named Al Tamimi (Sunflower) as his proxy beginning 3:30 pm on 8/19, Al Tamimi (Sunflower) named Ryan Yokely (Sunflower) as his proxy beginning 8/20, Bill Grant (SPS/Xcel) named Jordan Schmick (SPS/Xcel) as his proxy beginning 10:30 am on 8/20.

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 – August 19-20, 2015 Agenda)

Kurt Stradley (LES) made a motion; seconded by Paul Dietz (Westar) to adopt the agenda. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

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

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following items:

Approval of Meeting Minutes – May 20th-21st, 2015 (Attachment 5 – ESWG 05.20-21.15 Minutes)
Approval of Meeting Minutes – June 3rd, 2015 (Attachment 6 – ESWG 06.03.15 Minutes)
Approval of Meeting Minutes – June 18th, 2015 (Attachment 7 – ESWG 06.18.15 Minutes)
Approval of Meeting Minutes – July 1st, 2015 (Attachment 8 – ESWG 07.01.15 Minutes)

The consent agenda was approved unanimously.

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

Alan Myers (ITC Great Plains) updated the group on the activity of the TPITF. The TPITF has agreed upon implementing an 18 month rolling planning process which includes an annual report with a recommended portfolio of solutions. The first 6 months would be dedicated to building models with the final 12 months dedicated to the assessment of the models. In order to produce an annual report, the modeling portion of the process would overlap with the last 6 months of the assessment portion.

Agenda Item 5 – Study Schedules

Agenda Item 5a – 2017 ITP10 Schedule

Juliano Freitas (SPP Staff) updated the group on the 2017 ITP10 Schedule. (Attachment 8 – 2017 ITP10 Schedule)

Agenda Item 6 – RR56[1]

Tony Green (SPP Staff) gave an update to the ESWG on the changes to RR56 made by the Competitive Transmission Project Task Force (CTPTF) and Project Cost Working Group (PCWG). (Attachment 9 – Business Practices RR 56 Recommendation Report_PCWG_08102015)

Wayman Smith (AEP) made a motion; seconded by Bill Grant (SPS) to approve the changes embodied in the posted RR56. The motion was approved unanimously.

Agenda Item 7 – 2015 Regional Review

Brett Hooton (SPP Staff) informed the group of the correction to the model posting and incorporation of changes to the 2015 Regional Review model since the last meeting and requested approval of the model.

Natasha Henderson (GSEC) made a motion; seconded by Noman Williams (South Central MCN) to approve the 2015 Regional Review model. The motion was approved unanimously.

Clayton Mayfield (SPP Staff) reviewed the preliminary results of the Regional Review of the projects approved in the SPP-MISO Coordinated System Plan (CSP) study. Three projects were analyzed for benefits in SPPs regional model to verify results of the joint model from the CSP. Select benefit metrics were analyzed including APC benefit, wheeling through and out revenues, and benefit of avoided reliability projects. The results are preliminary and analysis is still ongoing. Members were concerned with the results of the zonal benefits. While some projects were showing regional benefit, utilizing two data points to extrapolate 40-year benefits for a single project at a time creates large volatility in overall benefit from zone to zone. Members suggested Staff find a way to display the data in a different form when presenting to other groups. (Attachment 10 – Regional Review Preliminary Results)

Agenda Item 8 – SPP.org Sneak Peak

Derek Wingfield (SPP Staff) gave an update on the progress of the SPP.org website redesign. Derek highlighted the process for being added to the website as a user from a working group member perspective and non-working group member perspective in order to use full functionality of the site and signing up for working group exploders. An email notification will be sent out to all exploders when all stakeholders will need to begin the process. Derek also pointed out the enhanced search functionality and the improved calendar/meeting information. (Attachment 11 – SPP.org Sneak Peek)

Agenda Item 9 – EPA Clean Power Plan Discussion

[This item was moved to the end of the agenda and not discussed] (Attachment 12 – EPA Clean Power Plan)

Agenda Item 10 – 2017 ITP10 Scope

Agenda Item 10a – Data Inputs and Study Methodology

[This item was moved to the end of the agenda and not discussed]

Agenda Item 10b – Futures Assumptions

Solar Assumptions

Chris Jamieson (SPP Staff) began the Futures assumptions discussion focusing on the "substantial" solar development drivers including large (utility) scale in all three Futures and rooftop (distributed) in Future 3 (expected case). Leveraging existing public IRP information from large U.S. utilities, Staff recommended installed capacity amounts by subregion (IS, Nebraska, KS/MO, South). There was much discussion

[1] Upgrade Determination & Short-Term Reliability Project Process

about the recommended capacity as well as the accreditation and capacity factors that would be used to incorporate the solar assumptions into the base model prior to beginning phase 2 of the resource plan. After discussion, members recommended slight adjustments to the proposed capacity inclusion.

Bill Grant (SPS) made a motion; seconded by Natasha Henderson (GSEC) to accept the inclusion of utility scale solar capacity in Future 3 at 1%, 3% and 6% of peak demand for 2020, 2025, and 2035, respectively. The motion passed with three opposed; Pat McCool (KCPL), Wayman Smith (AEP), and Paul Dietz (Westar).

Pat McCool voted no for the following reason: The amount of assumed solar installations and the projected solar capacity factors by region within SPP should vary, rather than be flat percentages, given the variance in solar resource potential in the north/south/east/west. There is no clear logic for the percentages of solar chosen for inclusion in the 3 futures (for example, 1%, 3%, 6% of system peak demand in 2020,2025,2035 for Future 3), and there should be something to point to that lends support to these assumptions.

Wayman Smith voted no for the following reason: At the time of the vote, it was not clear that these values would be reviewed with a chance to modify. I was hesitant to approve without having an idea of how much total capacity would be needed to meet reserve requirements. Had I known that these were just a starting point and could be modified, I would have supported.

Paul Dietz voted no for the following reason: Half that amount made more sense given the feedback we received at the meeting from various stakeholders.

Paul Dietz (Westar) made a motion; seconded by Tim Owens (NPPD) to accept the inclusion of rooftop (distributed) solar capacity in Future 3 at 0.5%, 1% and 2% of peak demand for 2020, 2025, and 2035, respectively. The motion passed with two opposed, Pat McCool (KCPL) and Natasha Henderson (GSEC), and one abstention, Bill Grant (SPS).

Pat McCool voted no for the following reason: The amount of assumed solar installations and the projected solar capacity factors by region within SPP should vary, rather than be flat percentages, given the variance in solar resource potential in the north/south/east/west. There is no clear logic for the percentages of solar chosen for inclusion in the 3 futures (for example, 1%, 3%, 6% of system peak demand in 2020,2025,2035 for Future 3), and there should be something to point to that lends support to these assumptions.

Natasha Henderson voted no for the following reason: GSEC believes the % are too high, partly due to the fact that the way distributed is treated in the SPP formula for capacity for utility scale solar, decreases the capacity value of utility scale solar.

Bill Grant abstained from the vote.

Natasha Henderson (GSEC) made a motion; Tim Owens (NPPD) to accept the inclusion of utility scale solar capacity in Futures 1 and 2 at 3% and 5% of peak demand for 2020 and 2025, respectively. The motion passed with two abstentions, Bill Grant (SPS) and Pat McCool (KCPL).

Bill Grant abstained from the vote.

Members accepted an adjusted version of Staff's solar proposal in order to continue the study process but reserve the right to make adjustments after preliminary results from phase 2 of the resource plan are available.

Minimum Capacity Reduction Impacts to Coal Retirements and Cycling

Kelsey Allen (SPP Staff) presented findings on the impact to operation and potential retirement of coal units due to the adjustment of operational minimum capacity. Members asked Staff in a previous meeting to analyze how a reduction of the minimum capacity of coal units would impact the potential retirements

needed in SPP's CPP analysis and the difference in cycling of those units. SPP found that a reduction of minimum capacity produced minimal impact in needed retirements to meet CPP compliance or cycling of the units. The greatest impact to cycling was the application of a carbon cost adder which drove a higher use of natural gas fuel over coal.

Coal Retirements as a Tool for CPP Compliance

Kelsey Allen (SPP Staff) presented the methodology used by SPP during its CPP compliance analysis to determine incremental coal retirements as a tool to meet carbon emission goals. Staff recommended leveraging this analysis to determine a ranking of units for potential retirement to be called upon in meeting emission goals in Future 1 and 2. Staff developed a tiered approach that included a combination of annual capacity factor under a carbon cost adder and age for coal steam units and average cost/MWh and age for gas steam units. There was much discussion on this topic. The main concerns were related to the firmness of the list and the opportunity to make adjustments to it once preliminary results of the phase 2 resource plan are available as well as potential use of the list by outside parties who might suppose utilities' future plans.

> **Paul Dietz (Westar) made a motion to accept Staff's recommendation as a starting point and use this method to come back with preliminary results. The motion was withdrawn.**
>
> **Paul Dietz (Westar) made a motion to accept Staff's method for ascertaining an assumed carbon price and retirement schedule with the understanding that after the retirement schedule has been determined the members have the opportunity to review and reject. The motion failed for lack of a second.**

ACTION ITEM: Staff to draft a disclaimer for decisions in the 2017 ITP10 related to the Clean Power Plan.

Staff intended to develop a ranking of the units based on the proposed criteria and send a list for utilities to review for reasonableness, as well as provide any detail on exceptions that might include units with completed retrofits, small generation portfolios or repowering with natural gas.

> **Paul Dietz (Westar) made a motion; seconded by Wayman Smith (AEP) to accept Staff's method to produce a list of potential retirements [to be utilized in the development of Future 1 and Future 2], including the assumed carbon price, that will be reviewed for individual unit rejection by the stakeholders**

ACTION ITEM: Staff to develop a list of potential retirements and send out for stakeholder review.

(Attachment 13 – 2017 ITP10 Futures Assumptions)

Agenda Item 10c – Portfolio Consolidation Methodology

[This item was moved to the end of the agenda and not discussed] (Attachment 14 – 2017 ITP10 Portfolio Consolidation)

Agenda Item 11 – Non-Designated Resources

Kelsey Allen (SPP Staff) updated the group on the latest chapter of the future Non-Designated Resource (NDR) inclusion process. SPP Staff received responses from Generator and Transmission Owners on the status of each project in the Generation Interconnection queue not already in-service or designated to a utility in the 2017 ITP10 generation review. Staff focused on responses to two key questions to develop a recommendation: 1. Has construction of the generating resource with major equipment procurement contracts awarded commenced? 2. Has the TO started construction of the TOIFs and NUs? If the GO and TO answered yes to those two questions then the resource was included in the recommendation. Based on the responses, Staff recommended that approximately 1GW of NDR capacity included in the 2017 ITP10, which would require an adjustment to the approved 2017 ITP10 Generation Review. (Attachment 15 – 2017 ITP10 Non-Designated Resources) (Attachment 16 – 2017 ITP10 Non-Designated Resources)

Paul Dietz (Westar) made a motion; seconded by Kurt Stradley (LES) to adopt Staff's recommendation of the list NDRs to be included in, and make appropriate changes for, the 2017 ITP10. The motion passed with two opposed: Bill Grant (SPS) and Alan Myers (ITC Great Plains.

Alan Myers voted no for the following reason: It is my opinion that at least a couple of the projects eliminated from the final list have demonstrated commitment commensurate with the purpose of the list and should have been included. SPP asked ITC for additional information to which ITC is not privy and for evidence of milestones for these particular projects which are not yet timely. The absence of these pieces of information, in my opinion, does not diminish the financial commitments already made by the projects in question.

Agenda Item 12 – RCAR II Modeling Discussion

[This item was moved to the end of the agenda and not discussed]. (Attachment 17 – RCAR II Modeling Discussion)

Agenda Item 13 – Non-Transmission Solution (NTS) Evaluation in the ITP

Kirk Hall (SPP Staff) discussed the development of a new process to fairly evaluate non-transmission solutions in the ITP processes. Members questioned staff's identification of a non-transmission solution. Kirk pointed out that all non-transmission solutions, including legacy transmission operating guides, would need to be submitted to SPP staff through SPP's Request Management System in order to be evaluated against other solutions. Staff plans to revisit this topic with the ESWG in the future, as necessary, to identify evaluation processes. (Attachment 18 – Non-Transmission Solution Evaluation)

Agenda Item 14 – Non-Standard Project (NSP) Evaluation in the ITP

Kirk Hall (SPP Staff) discussed the development of a new process to evaluate non-standard solutions in the ITP processes. Staff plans to determine a set of non-standard solution types then identify a list of decision-making studies that would need to be performed for each project type to ensure that these studies are performed before a decision is made on whether the project should be selected or not. Staff plans to continue working this item through the stakeholder process.

Agenda Item 15 – MOPC Action Item 255[2]

[This item was not discussed]. (Attachment 19 – MOPC Action Item 255)

Closing Items

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion. Staff mentioned the potential need to continue pursuing energy efficiency as a tool for emissions reduction in Futures 1 and 2. Due to the lack of time to complete the agenda items, a conference call will be scheduled the week of 8/24.

List of action items from the meeting:

1. Staff to draft a disclaimer for decisions in the 2017 ITP10 related to the Clean Power Plan.
2. Staff to develop a list of potential retirements and send out for stakeholder review.

The meeting was adjourned at 12:30 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

[2] Review the method to determine the Cost of Congestion as it relates to Outages for Rebuilds approved

SPP Southwest Power Pool

8/19

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

August 19-20, 2015

Magnolia Hotel/Denver, CO

• ATTENDANCE LIST •

Name	Company
Chris Jamieson	SPP
Jason Dan	SPP
JASON CHAPLIN	OCC
Michael Wegner	ITC
Sam Loudenslager	SPP
Tony Green	SPP
Adam McKinnie	Mo PSC
AL Tamimi	SEPC
Paul Dietz	Westar
Jonathan Abebe	Clean Line Energy
Norma Williams	South Central MCN
Steve Gaw	Wind Coalition
Eric Burkey	Ameren
Natasha Henderson	ASEC
JULIANO SCHRAMM FERREIRAS	SPP
Alan Myers	ITC
Carrie Simpson	Invenergy
Lauren Quillian	Xcel Energy
Antoine Lucas	SPP
Kelsey Allen	SPP

Southwest Power Pool

8/19

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

August 19-20, 2015

Magnolia Hotel/Denver, CO

• ATTENDANCE LIST •

Name	Company
JORDAN SCHMICK	XCEL ENERGY / SPS
Clayton Mayfield	SPP
Chris Matthes	AEP
Wayman Smith	AEP
Tim Owens	NPPD
Kurt Strauch	LES
BILL GRANT	XCEL/SPS
Brett Hooton	SPP
Kirk Hall	SPP
BILL LEUNG	ME POWER REVIEW BOARD
Bethany King	Empire District Electric
Michael Massey	AECC
Pat McCool	KCPL
Ed Pfeiffer	Quanta-Technology

8/20

Southwest Power Pool

Southwest Power Pool, Inc.

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August 19-20, 2015

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• ATTENDANCE LIST •

Name	Company
Chris Jamieson	SPP
Kirk Hall	SPP
JASON CHAPLIN	OCC
Michael Wegner	ITC
Adam McKinnie	MO PSC
Paul Dietz	Westar
BILL GRANT	XCEL/SPS
Natasha Henderson	CNSEC
Antoine Lucas	SPP
JULIANO FAGUNDES	SPP
Alan Myers	ITC
Kelsey Allen	SPP
JORDAN SCHMICK	XCEL ENERGY/SPS
Wayman Smith	AEP
Tim Owens	NPPD
KURT STRUDLEY	LES
Pat McCool	KCPL
BRUCE CLOSE	XCEL ENERGY/SPS

8/20

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

August 19-20, 2015

Magnolia Hotel/Denver, CO

• ATTENDANCE LIST •

Name	Company
Bethany King	Empire District
Michael Massery	AECC
Meena Thomas	Texas PUC
Ed Pfeiffer	Quanta Technology
Sam Loudenslager	SPP

Company	Last Name	First Name
Clean Line Energy	Abebe	Jonathan
Southwest Power Pool	Allen	Kelsey
Southwest Power Pool	Barker	Tamika
Southwest Power Pool	Bell	Adam
City Utilities of Springfield	Boshears	John
City Utilities of Springfield	Bradshaw	Jerry
Southwestern Public Service Company	Buffington	Brian
Ameren	Burkey	Eric
OCC	Chaplin	Jason
City Utilities of Springfield	Collier	Randy
Xcel Energy/SPS	Cude	Bruce
SPP	Davis	Jason
Westar	Dietz	Paul
Basin Electric Power Cooperative	Erhardt	Blaine
SPP	Freitas	Juliano
Basin Electric Power Cooperative	Frisk-Thompson	Lori
Grand River Dam Authority	Fultz	Joe
Wind Coalition	Gaw	Steve
Southwest Power Pool	Gephardt	Liz
MO PSC	Ghomsi	Noumvi
Tri County Electric	Giles	Chris
Xcel/SPS	Grant	Bill
Southwest Power Pool	Greb	Amber
SPP	Green	Tony
SPP	Hall	Kirk
GSEC	Henderson	Natasha
SPP	Hooton	Brett
OGE Energy Corp	Howell	Leon
Omaha Public Power District	Iverson	Jon
SPP	Jamieson	Chris
Empire District Electric	King	Bethany
East River Electric Power Cooperative	Knofczynski	John
City Utilities of Springfield	Knottek	Jeff
American Electric Power	Lao	Hongmou
Nebraska Power Review Board	Leung	Bill (William)
SPP	Loudenslager	Sam
SPP	Lucas	Antoine
AECC	Massery	Michael
AEP	Mathes	Chris
Southwest Power Pool	Maxey	Sherri
SPP	Mayfield	Clayton
KCPL	McCool	Pat
MO PSC	McKinnie	Adam

Southwest Power Pool	Mital	Rosemary
ITC	Myers	Alan
NPPD	Owens	Tim
Quanta - Technology	Pfeiffer	Ed
Xcel Energy	Quillian	Lauren
Southwest Power Pool	Roberts	Nikki
Southwest Power Pool	Ross	Joshua
Basin Electric Power Cooperative	Schiling	Garrett
Xcel Energy/SPS	Schmick	Jordan
Basin Electric Power Cooperative	Severson	Jeremy
AEP Oklahoma Transmission Company, Inc.	Sharma	Anita
Omaha Public Power District	Shipman	Jon
GDS Associates	Shook	Jason
Invenergy	Simpson	Carrie
AEP	Smith	Wayman
Occidental Energy Ventures Corp	Soles	Tim
Omaha Public Power District	Spargo	David
Southwest Power Pool	Speer	Jason
Missouri Joint Municipal EUC	Starnes	Heather
LES	Stradley	Kurt
Duke-American Transmission Company, LLC	Tadych	Todd
SEPC	Tamimi	Al
Texac PUC	Thomas	Meena
ABB	Toplyn	Bret
	Tschosik	Kevin
Tenaska Power Services Co	Varnell	John
Oklahoma Municipal Power Authority	Watt	Michael
ITC	Wegner	Michael
South Central MCN	Williams	Noman
Southwest Power Pool	Wingfield	Derek
SEPC	Yokley	Ryan

Email	Attendance
	In Person
	In Person
tbarker@spp.org	Net Conference
abell@spp.org	Net Conference
john.boshears@cityutilities.net	Net Conference
jerry.bradshaw@cityutilities.net	Net Conference
Brian.G.Buffington@xcelenergy.com	Net Conference
	In Person
	In Person
randy.collier@cityutilities.net	Net Conference
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	In Person
	In Person
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	In Person
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jfultz@grda.com	Net Conference
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jeff.knottek@cityutilities.net	Net Conference
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bleung@bjleung.com	In Person
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Lauren.p.quillian@xcelenergy.com	In Person
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asharma@aep.com	Net Conference
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tim_soles@oxy.com	Net Conference
dspargo@oppd.com	Net Conference
jspeer@spp.org	Net Conference
hstarnes1969@gmail.com	Net Conference
	In Person
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	In Person
	In Person
bret.toplyn@us.abb.com	Net Conference
	Net Conference
jvarnell@tnsk.com	Net Conference
mwatt@ompa.com	Net Conference
	In Person
	In Person
dwingfield@spp.org	Net Conference
Yokley-ryokley@sunflower.net	Net Conference

1. **Al Tamimi Proxy to Ryan Yokely (8/20)**

From: Tamimi, Al [mailto:atamimi@sunflower.net]
Sent: Wednesday, August 19, 2015 3:32 PM
To: Myers, Alan
Cc: Kelsey Allen
Subject: ESWG Proxy

Alan,
As I mentioned to you earlier, Ryan Yokley will have my proxy for tomorrow's meeting.
Thanks,
Al

Al Tamimi, Ph.D., P.E.
Sunflower Electric Power Corporation
V.P., Transmission Planning, Policy & Corporate Compliance
P.O.BOX 1020
Hays, Kansas 67601
Office: 785-623-3336
Cell: 785-656-0435
atamimi@sunflower.net

2. **Bennie Weeks proxy to Bill Grant**

From: Weeks, Bennie F [mailto:Bennie.Weeks@XCELENERGY.COM]
Sent: Wednesday, August 12, 2015 10:01 AM
To: Kelsey Allen; amyers@itcgreatplains.com
Cc: Grant, William
Subject: ESWG Meeting in Denver - Aug. 19-20

Hello Kelsey and Allen,
I will not be able to attend the ESWG meeting on Aug. 19-20. I am designating Bill Grant as my proxy for this meeting.

Bennie Weeks
Xcel Energy | Responsible By Nature
Mgr., Resource Planning
600 S. Tyler, Suite 29C01 Amarillo, Texas 79101
P: 806.378.2508 C: 806.316.6313
E: Bennie.Weeks@xcelenergy.com

3. **Don Le proxy to Noman Williams**

From: Le, Don [mailto:Don.Le@nexteraenergy.com]
Sent: Friday, August 14, 2015 9:58 AM
To: Williams, Noman; Kelsey Allen; amyers@itcgreatplains.com
Subject: ESWG 8/19-20 Proxy

Kelsey/Allen,

I'm unable to attend the upcoming ESWG Meeting in Denver and I'd like Noman Williams to be my proxy.

Don Le
System Planning Manager
Lone Star Transmission, LLC
NextEra Energy Transmission, LLC
(M) 713-366-6105
(O) 512-236-3144
Don.Le@NextEraEnergy.com

4. **Kip Fox proxy to Wayman Smith**

From: Kip M Fox [mailto:kmfox@aep.com]
Sent: Monday, June 01, 2015 9:19 AM
To: Myers, Alan; Juliano Freitas; Kelsey Allen
Cc: Smith, Wayman
Subject: Proxy for Wayman Smith on August 19-20 ESWG meeting

Please let this email serve as my notification to have Wayman Smith be my proxy for the ESWG meeting in Denver on August 19-20, 2015. If you have any questions, please advise.

Thank you, Kip

Kip Fox
Director, Transmission Asset Strategy and Grid Development
American Electric Power
Transource Energy, LLC
1201 Elm Street
Suite 800
Dallas, Texas 75250
kmfox@aep.com
office: 214-777-1063
cell: 972-400-1384

5. **Noman Williams proxy to Al Tamimi**

From: Noman Williams [mailto:Nwilliams@gridliance.com]
Sent: Wednesday, August 19, 2015 2:13 PM
To: Myers, Alan; Kelsey Allen
Cc: Tamimi, Al
Subject: SPP ESWG Proxy

Alan and Kelsey,

I need to leave about 3:30 this afternoon so I will provide my proxy to Al Tamimi when I leave.

Noman Williams
Senior Vice President Engineering & Operations, COO
South Central MCN, LLC
Midcontinent MCN, LLC
Phone: 816-492-2014
Cell: 785-259-5110
Nwilliams@gridliance.com

GRIDLIANCE

A Blackstone Company

6. **Bill Grant proxy to Jordan Schmick (8/20, 10:30 am)**

[Verbal]

ECONOMIC STUDIES WORKING GROUP

August 19th – 20th, 2015

Magnolia Hotel, Denver, CO

• A G E N D A •

Wednesday 1:00pm – 5:00pm

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 Meetings Minutes – May 20th, 2015
    b. Approval of Meetings Minutes – June 3rd, 2015
    c. Approval of Meetings Minutes – June 18th, 2015
    d. Approval of Meetings Minutes – July 1st, 2015
4. Transmission Planning Improvement Task Force (TPITF) Update.....Alan Myers (10 minutes)
5. Study Schedules[1] ..... Juliano Freitas (15 minutes)
    a. 2017 ITP10
6. RR56[1,2] (Approval Item).....Tony Green (30 minutes)
7. 2015 Regional Review..... Clayton Mayfield (60 minutes)
    a. Regional Review Model[3] (Approval Item)
    b. Regional Review Preliminary Results
8. SPP.org Sneak Peak[1]..... Derek Wingfield (15 minutes)
9. EPA Clean Power Plan Discussion .....All (60 minutes)
    a. SPP Goal Computation (Kelsey Allen)
    b. Final Rule Impacts

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[1] Background Material Included
[2] Upgrade Determination & Short-Term Reliability Project Process
[3] Posted on SPPs TrueShare

10. 2017 ITP10 Scope ..... SPP Staff (30 minutes)
    a. Data Inputs and Methodology
    b. Portfolio Consolidation Methodology[1]

Thursday 8:00am – 12:00pm

10. 2017 ITP10 Scope (Continued) ..... SPP Staff (60 minutes)
    c. Futures Assumptions
11. Non-Designated Resources[1] (Approval Item) ..... Chris Jamieson (30 minutes)
12. RCAR II Modeling Discussion[1] ..... Josh Ross (60 minutes)
13. Non-Transmission Solution (NTS) Evaluation in the ITP[1] .....Kirk Hall (30 minutes)
14. Non-Standard Project (NSP) Evaluation in the ITP .....Kirk Hall (15 minutes)
15. MOPC Action Item 255[4] ..... SPP Staff (30 minutes)
16. Closing Items ..... All (5 minutes)
    a. Summary of Action Items (Kelsey Allen)
    b. Future Meetings
        i. September 23rd, 2015: 8th Floor AEP Offices, Dallas, TX
        ii. October 22nd, 2015: NextEra HQ, Juno Beach, FL
        iii. November 18th-19th, 2015: SPP Corporate Offices, Little Rock, AR
        iv. December 10th, 2015: 8th Floor AEP Offices, Dallas, TX

[1] Background Material Included
[4] "Review the method to determine the Cost of Congestion as it relates to Outages for Rebuilds approved"

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

August 19th, 2015

ID	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 23, 2012	In Progress Staff	A draft straw man will be provided to the group at the end of April for review.
127	SPP Staff will develop a process to address interaction between SPP departments (Generation Interconnection, Aggregate Studies, Economic Planning, Steady State and Modeling) to detect basic errors in our models.	August 7, 2014	In Progress Staff	
128	SPP Staff will explain to ESWG Members the process to submit data to model on demand.	August 7, 2014	In Progress Staff	
147	ESWG to re-evaluate the modeling issues related to load pockets and wind in the RCAR II.	March 31st, 2015	In Progress ESWG	June 18th: Continue discussion for both a near term (2017 ITP10) and longer term solution.
148	Staff to develop a formal member review procedure for review of data and results related to economic studies.	March 31st, 2015	In Progress Staff	
149	ESWG to discuss how staff will request generation and load data in future studies.	May 1st, 2015	In Progress ESWG	
150	ESWG to develop criteria for including non-firm generation in the ITP 10 and 20 models, within 60 days.	May 1st, 2015	Complete ESWG	
151	Staff to look into optional software tools for use in ITP studies	May 20th, 2015	In Progress Staff	
152	Continue review resource siting methodology with utilities and develop a recommendation for the 2017 ITP10	May 20th, 2015	In Progress Staff	
153	MOPC action item 255: Review the method to determine the cost of congestion, as it relates to outages for rebuilds approved.	July 9, 2015	In Progress ESWG	SPP Staff to compile comments from the group and develop a “straw man” proposal for discussion

154	SPP staff to work with ESWG members to create a data request to gather the energy efficiency amount included in the model	July 30, 2015	In Progress Staff	

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

May 20th - 21st, 2015

Sheraton Downtown, Oklahoma City, OK

• SUMMARY OF ACTIONS TAKEN •

1. Approved the March 31st - April 1st, and May 1st, 2015 meeting minutes
2. Adopted the changes to the representation and voting structure section of the ESWG charter.
3. Approved a motion to maintain the reserve margin at 13.6% for resource planning in the 2017 ITP10 study
4. Approved the use of actual wind accreditation values for wind farms with 3 years of historical data, and to follow SPP criteria for wind farms with less than 3 years of historical data
5. Approved a motion to follow SPP criteria for accreditation of solar resources
6. Voted to utilize the status quo methodology for modeling of fuel, wind, and emissions prices (Ventyx reference case, NYMEX futures, DOE growth rates)
7. Approved removing the must run flag for all base load units, except nuclear, for all three futures

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

May 20th - 21st, 2015

Sheraton Downtown, Oklahoma City, OK

• 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 26 in person attendees and 41 web conference participants representing 12 of 12 ESWG members. (Attachment 1 – May 20-21st, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Bennie Weeks (SPS) named Jason Schmidt (Xcel Energy) 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 – May 20-21st, 2015 Agenda)

Kurt Stradley (LES) made a motion; seconded by Leon Howell (OGE) to adopt the agenda. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the past action items. Item 076, to analyze the aggregate studies impact on the 2015 ITP10, was marked complete. The process of incorporating NTC projects issued after approval of the ITP powerflow models will be documented in the ITP Scope. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following items:

Approval of Meetings Minutes – March 31st - April 1st, 2015 (Attachment 5 – ESWG 03.31.15 Minutes)
Approval of Meetings Minutes – May 1st, 2015 (Attachment 6 – ESWG 05.01.15 Minutes)

The consent agenda was approved unanimously.

Agenda Item 4 – Study Schedules

Agenda Item 4a – SPP-MISO CSP & Regional Review

Juliano Freitas (SPP Staff) updated the group on the SPP-MISO CSP Schedule. Staff is currently working on solution refinement, report development, and interregional cost allocation. Sensitivities will begin in June. The regional review is set to start on May 28th. (Attachment 7 – SPP-MISO CSP & Regional Review Schedule)

Agenda Item 4b – 2017 ITP10 Schedule

Juliano Freitas (SPP Staff) updated the group on the 2017 ITP10 Schedule. Staff has posted the Load and Generation, as well as the renewable survey for stakeholders to review. He reminded the group of the deadlines for feedback and the anticipated approval dates. Upcoming milestones are the resource

plan and the economic model development. With more focus on deadlines, the group discussed the efficiency of the current tools utilized by SPP and requested Staff to investigate software optionality for future ITP studies. The group also asked about the coordination of the Wind Integration Study currently being performed by SPP Operations Staff and the ITP process. There was concern expressed about potential differences in the results coming out of the WIS and what might be proposed through the ITP process. (Attachment 8 – 2017 ITP10 Schedule)

ACTION ITEM: Staff to look into optional software tools for use in ITP studies.

Agenda Item 5 – Transmission Planning Improvement Task Force (TPITF) Update

Alan Myers (ITC Great Plains) gave an update to the ESWG. The MOPC approved the TPITF charter, the main focus of this task force will be policy level decisions. The group would like to keep the TPITF as a standing update.

Agenda Item 6 – SPP-MISO CSP Regional Review Process

Brett Hooton (SPP Staff) explained that the purpose of the regional review study is to have a regional evaluation of the recommended interregional projects from the SPP-MISO Coordinated System Planning (CSP) Study. Projects must have an SPP B/C ratio of at least 1.0, based on a selection of ITP10 benefit metrics. Brett presented the potential interregional projects to be reviewed. The group discussed that if a project from the CSP replaces an ITP10 project, it must be evaluated by the same benefit metrics as the ITP project. Brett informed the group that the model has been posted and stakeholders have until June 10th to submit comments. Members requested that Staff update the Regional Review model with data submitted through the 2017 ITP10 Generation and Load Review. A draft scope will be posted on May 27th, soliciting feedback through June 4th. (Attachment 9 – SPP-MISO CSP Regional Review Process)

Agenda Item 7 – ESWG Charter Review

Kelsey Allen (SPP Staff) summarized the proposed change to the charter. The change increases the membership limit from 14 members to 18. Increasing each of the voting categories by one member. There will be 17 voting members and one non-voting regulatory liaison member. (Attachment 10 – ESWG Draft Charter)

> **Paul Dietz (Westar) made a motion; seconded by Leon Howell (OGE) to adopt the changes to the representation and voting structure section of the ESWG charter. The motion was approved unanimously.**

Agenda Item 8 – 2017 ITP10 Load and Generation Review Update

Kelsey Allen (SPP Staff) gave an update to the group on the status of the load and generation review. He asked for feedback or any questions of the current process. He reminded everyone that changes to the economic model are due back to staff by June 2nd.

Agenda Item 9 – 2017 ITP10 Scope

Agenda Item 9a – Data Inputs and Methodology

Kelsey Allen (SPP Staff) presented to the group the current assumptions for the 2017 ITP10 study and the decision points that need to be addressed. The discussion began with prototypes, the group could not reach a decision on how to utilize the two data sources, EIA and Lazard. The ESWG asked staff to research and come back with a proposal. Discussion then moved onto the zonal reserve margin; the Capacity Margin Task Force (CMTF) is in the process of re-evaluating the SPP reserve margin, but the ITP process waiting on their decision would present a timing issue. Pat McCool (KCPL), as a member of the CMTF, felt that the 2017 ITP10 should utilize current approved criteria.

> **Pat McCool (KCPL) made a motion; seconded by Kip Fox (AEP-Transource) to maintain the reserve margin at 13.6% for the 2017 ITP10 study. The motion was approved unanimously.**

The ESWG revisited the renewable accreditation used in the most recent ITP study. The Generation Working Group (GWG) recently approved criteria to increase the capacity accreditation for both wind and solar. The group felt comfortable with the decisions made by the GWG.

Kip Fox (AEP-Transource) made a motion; seconded by Paul Dietz (Westar) to use actual wind accreditation values for wind farms with 3 years of historical data, and to follow SPP criteria, for wind farms with less than 3 years of historical data. The motion was approved unanimously.

Leon Howell (OGE) made a motion; seconded by Paul Dietz (Westar) to follow SPP criteria for accreditation of solar resources. The motion was approved unanimously.

In the 2017 ITP10, the 2005 NREL wind profile data was used to determine existing wind capacity factors, with a 15% increase being applied to new wind farms. Kelsey Allen (SPP) informed the group that there is a newer NREL dataset available that could be utilized. The group directed staff to gather more information and compare the 2012 NREL data to the currently used 2005 data.

When the conversation moved on to system topology, the consensus among the group was to use the 2025 ITP powerflow model developed in preparation for the 2016 ITPNT, with any necessary modifications. DC tie modeling was briefly discussed and Staff was directed to continue modeling the status quo of utilizing historical tie flows capped at long-term firm transmission service amounts.

Modeling parameters for the 2015 ITP10 utilized the Ventyx reference case for coal, oil, uranium, and emissions prices. NYMEX futures and DOE growth rates were used for natural gas prices. Wind was modeled with a cost $8/MWhr for variable O&M and curtailment. The group was comfortable moving forward with these assumptions. (Attachment 11 – 2017 ITP10 Data Inputs and Study Methodology)

Kip Fox (AEP-Transource) made a motion; seconded by Kurt Stradley (LES) to utilize the status quo methodology for modeling of fuel, wind, and emissions prices. The motion was approved unanimously.

Agenda Item 9b – Futures Assumptions

Kelsey Allen (SPP Staff) recapped the three futures approved by the board and began discussion that focused on how data inputs would be impacted in a CPP future. Discussion began with must run units and other unit operation. The group touched on a process to fairly evaluate operating directives against transmission solutions, operating minimums for based load units under the CPP futures, and other unit parameters.

Leon Howell (OGE) made a motion; seconded by Paul Dietz (Westar) to remove the must run flag for all base load units, except nuclear, for all three futures. Bary Warren (Empire) took exception to the motion because neither Empire nor SPP can control the operation of units outside the SPP BA, such as Plum Point. Paul Dietz (Westar) supported this concern. The motion was approved unanimously.

The group discussed the EPA goal calculation and timeline and came to the agreement to plan for the 2030 goal in the 2025 study year. Kelsey then presented a few different emissions limiting options to consider in order to reach emissions goals in the CPP futures. The discussion covered energy efficiency as a tool and the implications that may have on current load forecasts as well as leveraging unit retirements on an age, size, or technology basis. The ESWG directed staff to do more research and bring options and recommendations back to the group. (Attachment 12 – 2017 ITP10 Futures Assumptions)

Agenda Item 10 – Resource Expansion Methodology

Kelsey Allen (SPP Staff) gave a presentation on the resource expansion methodology. He offered potential solutions to improve the current methodology for inclusion of resources in the 2017 ITP10 study. The goal of the resource inclusion methodology is to better project the future mix of resources expected by the membership as well as to put bounds around the resources that can be included in the base models prior to the resource planning effort. The ESWG asked staff to refine the guidelines for these

processes and bring them to the next face to face meeting. (Attachment 13 – ITP Resource Expansion Methodology)

Agenda Item 11 – ITP Resource Siting Methodology

Chris Jamieson (SPP Staff) updated the group on the development of an SPP independent siting process. Chris gave a high level overview of the research Staff has completed which included general concepts that could be leveraged and employed as well as the siting processes of other RTOs. Staff's intent with the independent siting methodology is both to develop a regional process that attempts to mimic the siting methodologies of individual stakeholders as well as minimize the generator outlet facilities needed to interconnect the future resources. The ESWG directed staff to continue researching and come back with a recommendation. (Attachment 14 – ITP Resource Siting Methodology)

ACTION ITEM: Staff to continue reviewing the resource siting methodology with utilities and to develop a recommendation for the 2017 TIP10.

Closing Items

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

List of action items from the meeting:

1. Staff to look into optional software tools for use in ITP studies.
2. Staff to continue reviewing the resource siting methodology with utilities and to develop a recommendation for the 2017 TIP10.

The meeting was adjourned at 11:59 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 3rd, 2015

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. Approved the use of new "Other GI Firm" resources [not designated to a utility] to meet any potential renewable Mandate or Goal shortfalls.
2. Approved the resource inclusion methodology for the ITP studies, including the process of sending a request to the ESWG for resources that do not meet the criteria.
3. Approved the use of prototypes from Lazard's 2014 Levelized Cost of Energy Study (Version 8).
4. Approved the use of 2012 hourly wind profiles from the NREL 2012 WIND toolkit dataset.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 3rd, 2015

Net Conference

• 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 8:30 AM, welcomed those in attendance, and asked for introductions.

There were 45 web conference participants and 1 telephone participant representing 11 of 12 ESWG members. (Attachment 1 – June 3rd, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Don Le (NextEra) named Brian Gedrich (NextEra) as his proxy. (Attachment 2 – Proxies)

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 – June 3rd, 2015 Agenda)

> **Kip Fox (AEP-Transource) made a motion; seconded by Kurt Stradley (LES) to adopt the agenda. The motion was approved unanimously.**

Agenda Item 2 – 2017 ITP10 Generation and Load Review Update

Kelsey Allen (SPP Staff) gave an update to the group. He reminded them that June 2nd was the deadline for feedback on the Economic Model data and that staff is currently reviewing all of the updates for inclusion in the model.

Agenda Item 3 – ITP Resource Expansion Methodology

Kelsey Allen (SPP Staff) gave a presentation of the ITP resource expansion methodology. The response window for the renewable survey has closed and for companies who did not submit a response, staff will calculate values based on available state Mandates/Goals and the information in the Generation and/or Load review. These calculations will be provided to the Stakeholder for review. Staff recommended using non designated "Other GI Firm" resources to meet any potential renewable Mandate or Goal shortfalls.

> **Kip Fox (AEP-Transource) made a motion; seconded by Brian Gedrich (NextEra) to approve the use of new "Other GI Firm" resources [not designated to a utility] to meet any potential renewable Mandate or Goal shortfalls. The motion was approved unanimously.**

Kelsey reviewed the proposed ITP10/20 resource inclusion criteria:

Resources are to be included in the model if they have an executed Interconnection Agreement that is not on suspension and has minimal network upgrade costs. Otherwise, the facility will be included if it has a high probability of going into service and;

- a Resource Addition Request (RAR) has been sent to SPP requesting the generation capacity be included into the ITP**;**
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA; and
- The generating resource will have firm contract for delivery in one or more forms:

  - a) The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts; or
  - b) The utility to be designated will own and operate the resource or has procured a Purchase Power Agreement (PPA) from the generation owner.
- If a generating resource does not meet all the above requirements, a RAR for generation capacity to be included in a long-term ITP assessment can be made to ESWG on a case by case basis. ESWG will take into account the following, but not limited to, additional points:
  - i) a Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable;
  - ii) an RFP for the generating resource has been awarded, if applicable. All other resource expansion needs will be determined through the SPP resource planning process.

(Attachment 4 – ITP Resource Expansion Methodology)

Kip Fox (AEP-Transource) made a motion; seconded by Paul Dietz (Westar) to approve the proposed resource inclusion methodology for the ITP studies, including the process of sending a request to the ESWG for resources that do not meet the criteria. The motion was approved unanimously.

Agenda Item 4 – 2017 ITP10 Scope

Kelsey Allen (SPP Staff) presented prototype data source option to the group. In past ITP studies, the EIA Annual Energy Outlook report has been leveraged. Staff recommended utilizing the Lazard levelized cost of energy analysis data. The group agreed with this recommendation and requested that staff come back with details of how we will utilize the available data. (Attachment 5 – 2017 ITP10 Scope) (Attachment 6 - 2014 Lazard-Levelized Cost of Energy-Version 8.0)

Paul Dietz (Westar) made a motion; seconded by Leon Howell (OG&E) to approve using the Lazard data set for generation prototypes. The motion was approved unanimously.

Discussion moved on to the wind capacity factors, Kelsey reminded the group that in the last study, we used the 2005 NREL EWITS profiles, and increased the capacity factors of new wind farms by 15%. For the 2017 ITP10, staff is recommending to utilize the 2012 NREL toolkit dataset. This dataset was not available during the 2015 ITP10, it has higher capacity factors that reflect technological advances and it is also more comprehensive.

Leon Howell (OG&E) made a motion; seconded by Paul Dietz (Westar) to approve using the 2012 hourly wind profiles from the NREL 2012 WIND toolkit dataset. The motion was approved unanimously.

The group briefly discussed benchmarking and determined that they would like to continue looking at the same data as we have in previous studies; capacity factor by unit type, generation by unit type, production cost, LMP's, etc. The group also agreed to use the same process for the constraint assessment, beginning with the IDC Book of Flowgates and adding additional constraints using PAT.

When the topic of solution development was brought up, the main topic of conversation was the seams project cost sharing methodology. The 80/20 cost sharing may be the best option with some of our neighbors, but stakeholders would like to re-evaluate the cost sharing with MISO. Staff was also asked to investigate the 1-year B/C threshold by pulling data from past studies and looking at the addition of all metrics, the addition of the 40-year benefits, and the change in costs between Study and Conceptual estimates. The ESWG asked for more time to think about project selection and project grouping, but there was some concern about the 70% congestion relief threshold Staff used to filter potential economic projects.

Closing Items

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

There were no official action items from the meeting. SPP Staff and ESWG members will continue to refine methodology and ideas for the 2017 ITP10 scope and study.

The meeting was adjourned at 11:30 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 18th, 2015

AEP Offices 8th Floor, Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. Approved the revised ESWG Charter
2. Approved the Regional Review Scope as presented by staff
3. Approved the BEPC request for inclusion of the 3 generation facilities which include GI-1406 (Pioneer Recips), GI-1410 Lindahl Wind), and GI-1414 (Heart River Wind) in the 2017 ITP10 models
4. Approved the Load and Generation Review for the 2017 ITP10
5. Approved the Renewable survey as amended by SPS for the 2017 ITP10

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 18th, 2015

AEP Offices 8th Floor, 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 20 in-person participants, 37 web conference participants, and 1 phone participant representing 11 of 12 ESWG members. (Attachment 1 – June 18, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Paul Dietz (Westar) named Kip Fox (AEP-Transource) as his 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 – June 18, 2015 Agenda)

> **Kip Fox (AEP-Transource) made a motion; seconded by Bennie Weeks (SPS) to adopt the agenda. The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items. A number of the items will be discussed in today's meeting. Update to item 142, the PROMOD User group meeting is tentatively scheduled for August 4th-5th in Little Rock, AR. Item 150, criteria for non-firm generation was marked complete. (Attachment 4 – Past Action Items)

Agenda Item 3 – Transmission Planning Improvement Task Force (TPITF) Update

Alan Myers (ITC Great Plains) gave an update on the status of the TPITF. The major item from the last TPITF meeting was that many members want to eliminate the ITP20 study. There has also been discussion about combining the ITP Near-Term and ITP10 assessments. A less favored approach is to combine the ITPNT and TPL assessments. Staff is investigating the feasibility of these options.

Agenda Item 4 – Study Schedules

Agenda Item 4a – 2017 ITP10

Juliano Freitas (SPP Staff) gave an update on the status of the 2017 ITP10 Study. Staff is requesting approval of the load and generation review today. The milestones that staff is beginning to work on are the Resource Plan, Powerflow Model Development, Economic Model Development, and Benchmarking. The Scope was scheduled to go to MOPC in July; due to the remaining decisions to be made, the ESWG will need to finish the Scope in September in order to take to MOPC for approval in October. (Attachment 5 – 2017 ITP10 Schedule)

Agenda Item 4b – SPP-MISO CSP

Brett Hooton (SPP Staff) gave an update on the status of the SPP-MISO CSP Study. The Regional Review Study will begin in July. Staff has been incorporating the feedback received from Stakeholders into the Regional Review model. (Attachment 6 - SPP-MISO CSP Schedule)

Agenda Item 5 – ESWG Charter Review

Kelsey Allen (SPP Staff) gave an overview of the Charter and the changes that were made. The major changes were to the Scope of Activities and adding additional members. Details were added outlining the specific studies that the ESWG is involved in and what input they provide. Representation was changed to add four additional voting members, and one non-voting Regulatory Liaison member.

Kip Fox (AEP-Transource) made a motion; seconded by Don Le (NextEra Energy Transmission) to approve the revised ESWG Charter. The motion passed unanimously.

Agenda Item 6 – 2015 Regional Review Scope

Brett Hooton (SPP Staff) presented on the Regional Review Scope. The regional review analysis evaluates the approved interregional projects in a regional model; it does not consider new alternatives. Existing planned projects will be reviewed for redundancy and evaluated following the regional review methodology. For the 2015 Regional Review, projects must have a 40 year B/C ratio of 1.0, and be more cost effective than a regional solution to be considered beneficial. There were questions among the group on cost allocation. Brett explained that the Interregional cost allocation has already been determined based on the benefit split between SPP and MISO. The regional cost allocation will follow the current regional funding process. The ESWG requested that Staff provide the benefits on a zonal level. (Attachment 7 – 2015 Regional Review Scope)

Kip Fox (AEP-Transource) made a motion; seconded by Bennie Weeks (SPS) and Tim Owens (NPPD) to approve the 2015 Regional Review Scope as presented by staff. The motion passed unanimously.

Agenda Item 7 – 2017 ITP10 Resource Additions

Kelsey Allen (SPP Staff) presented on the resource additions for the 2017 ITP10. The presentation included the criteria for resources to be included in the study. The majority of additions met the criteria for inclusion and are included in the generation review that staff will present later in the meeting. Basin Electric Power Cooperative has one resource that did not meet the criteria. (Attachment 8 – 2017 ITP10 Resource Additions) Jeremy Severson (BEPC) presented a resource addition request to the group. Basin is requesting inclusion and ownership designation of three generating resources: Pioneer, Heart River Wind, and Lindahl Wind. (Attachment 9 – BEPC Waiver Request)

Kip Fox (AEP-Transource) made a motion; seconded by Kurt Stradley (LES) to approve inclusion of the 3 generation facilities which include GI-1406 (Pioneer Recips), GI-1410 Lindahl Wind), and GI-1414 (Heart River Wind) in the 2017 ITP10 models. The motion passed unanimously.

Kelsey Allen (SPP Staff) presented a list of non-designated resources to be included in the model. These resources meet the criteria for inclusion: Interconnection agreement, minimal network costs, and a high likelihood of going into service. There was a large amount of discussion on these units. The group was concerned that some of these units would not end up going into service. Many members felt that this list should not go into the model, but should be used for siting considerations instead. Staff will continue review of the resources and criteria with stakeholders to discuss these units. The ESWG also directed Staff to gather a list of resources for the Integrated System. (Attachment 10 – 2017 ITP10 NDR Additions)

Agenda Item 8 – 2017 ITP10 Load and Generation Review

Kelsey Allen (SPP Staff) opened the discussion by asking for any feedback or questions on the posted Load and Generation review workbooks. The group wanted it noted that all units other than nuclear should not be labeled as must run units. There was discussion on updating units that have received no member feedback with the ABB Nodal Simulation Ready Data. (Attachment 11 – 2017 ITP10 Load and Generation Data Submittals)

Kip Fox (AEP-Transource) made a motion; seconded by Don Le (NextEra Energy Transmission) to approve the Load and Generation Review for the 2017 ITP10 as posted. The motion passed with one abstention, Alan Myers (ITC Great Plains).

Agenda Item 9 – 2017 ITP10 Renewable Survey

Liz Gephardt (SPP Staff) presented the 2017 ITP10 Renewable Survey to the group. She opened the floor for discussion. Bennie Weeks (SPS) requested that their siting requirements be updated to New Mexico. This was the only change to the spreadsheet. (Attachment 12 – 2017 ITP10 Renewable Energy Survey)

Kip Fox (AEP-Transource) made a motion; seconded by Kurt Stradley (LES) to approve the Renewable Survey for the 2017 ITP10 as modified by SPS. The motion passed with one no vote, Leon Howell (OGE). Leon was concerned that by showing OGE's renewable requirement while Oklahoma has already met its state goal, resources could be added through the ITP process that should not be.

Agenda Item 10 – RCAR II Modeling Discussion

Josh Ross (SPP Staff) reminded the group of the previous discussion regarding the RCAR II modeling issues. The ESWG had directed staff to solve Issue #1, Trapped Generation Pockets, using a Hybrid Approach. Staff was also directed to bring back more information on another solution method, an Incremental Approach. This approach and results are detailed in the presentation. Josh also presented the results of Solutions to Issue #2, Load Pockets. For both of these issues, the suggested solutions do not address the problems. The group discussed other options, and wants to explore other alternatives. Staff was directed to continue working on these issue with a long term solution in mind. (Attachment 13 – RCAR Modeling Discussion)

ACTION ITEM: ESWG to re-evaluate the modeling issues related to load pockets and wind in the RCAR II, with a long term solution in mind.

Agenda Item 11 – 2017 ITP10 Scope

Agenda Item 11a – Data Inputs and Methodology

Kelsey Allen (SPP Staff) reviewed the assumptions that have already been approved for the 2017 ITP10. Discussion then moved on to the prototypes for the study: the ESWG approved the use of Lazard LCOE Analysis for prototype parameters at the June 3rd meeting. There was a lot of confusion on how the Lazard data was correlated and should be utilized for modeling. Staff was directed to gather more information and bring back a recommendation at a future meeting. (Attachment 14 – Data Inputs and Methodology)

Agenda Item 11b – Portfolio Consolidation Methodology

Kelsey Allen (SPP Staff) reviewed the consolidation methodologies used the in past ITP studies, from the 2010 ITP20 up to the 2015 ITP10. He then opened the floor for discussion and ideas on how to consolidate projects in the 2017 ITP10. Many options were discussed. Some liked the idea of a 'no-regrets' set of projects, and only choosing projects that show benefit in all three futures for consolidation. Another set of projects could be developed as a 'value' set which have value within the context of the ITP10 study but may be less certain than those selected as 'no regrets'. Consolidation methodology used by MISO was discussed; assign a weighting to each future, and each project is tested in all futures and a weighted sum of APC is calculated to compare against cost. The group agreed to continue the discussion at the July 9th meeting. (Attachment 15 – Consolidation Methodology)

Closing Items

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

List of action items from the meeting:

1. ESWG to re-evaluate the modeling issues related to load pockets and wind in the RCAR II, with a long term solution in mind.

The meeting was adjourned at 1:59 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

July 1st, 2015

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. Approved inclusion of Westar's Ninnescah Wind Project in the 2017 ITP10 models
2. Approved Staff's recommendation for defining economic needs
    a. Up to 25 constraints per future based on ranking of flowgate congestion cost will be identified as economic needs
    b. Constraints with less than $50,000 in annual congestion cost will be excluded as needs
3. Approved the Staff's recommendation for identifying policy needs (status quo)
    a. A shortfall of renewable mandates or goals by utility, by state will be identified as policy needs
    b. This only applies to mandates or goals based upon energy or capacity required to be deliverable

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

July 1st, 2015

Net Conference

• 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 8:30 AM, welcomed those in attendance, and asked for introductions.

There were 46 web conference participants and 1 telephone participant representing 10 of 12 ESWG members. (Attachment 1 – July 1st, 2015 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. Two proxies were identified; Al Tamimi (Sunflower) named Tom Hesterman (Sunflower) as his proxy. (Attachment 2 – Proxies)

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 – July 1st, 2015 Agenda)

> **Kurt Stradley (LES) made a motion; seconded by Kip Fox (AEP-Transource) to adopt the agenda. The motion was approved unanimously.**

Agenda Item 2 – 2017 ITP10 Resource Additions

Paul Dietz (WERE) presented a resource addition request to the group for the Ninnescah Wind Project. Westar has signed a PPA for 200 MW with the owner of this wind farm. There is a network transmission request being studied, and NextEra has a Generation Interconnection request at the Thistle substation. The first MW of power is expected to flow by December 2016. Paul made a recommendation that the ITP10 Model be updated to reflect this wind project. (Attachment 4 – Ninnescah Wind Project Westar)

> **Paul Dietz (WERE) made a motion; seconded by Kurt Stradley (LES) that for the sake of accuracy in the models, the Ninnescah wind project will be included in the 2017 ITP10. The motion was approved unanimously.**

Agenda Item 3 – ITP Resource Plan

Kelsey Allen (SPP Staff) gave an update on the ITP resource plan. Staff will send out a PPA data review later in the week requesting fleet PPA's needed for the 2017 ITP10 Resource Plan Phase 2 capacity margin calculations. SPP Staff will also be sending out a data request for plant specific data for the renewable capacity accreditation;, SPP Staff has leveraged information from the 2015 Long Term Reliability Assessment (LTRA) and plans to send the request out in early July. (Attachment 5 – 2017 ITP10 Resource Plan)

Agenda Item 4 – 2017 ITP10 Scope

Agenda Item 4a – Data Inputs and Methodologies

Kelsey Allen (SPP Staff) gave a recap of the assumptions that have been approved by the ESWG. Discussion began with the conventional machine minimum capacity, this is not surveyed as a part of the generation review. There were concerns about how the market monitor will view differences between what is being offered in market bids versus what is modeled in the ITP studies. SPP Staff recommended

reducing the minimum base load capacity for base load units to 25% to reflect potential operational minimums. Members requested more time to think about this topic. The group moved on to the needs assessments. For the economic needs assessment, SPP Staff recommends ranking the constraints based on flowgate congestion cost, and identifying up to 25 constraints, with over $50,000 in annual congestion cost. The group expressed some concern over the $50,000 congestion cost threshold, SPP Staff explained that there were a number of needs in the previous study with no economic benefit.

> **Paul Dietz (WERE) made a motion; seconded by Kip Fox (AEP-Transource) to accept SPP Staff's recommendation for determining the economic needs. The motion was approved with one opposed, Alan Myers (ITC Great Plains) voted no for the following reason; he would have preferred to stick with the previous process for one more study.**

SPP Staff sent out a renewable survey to request renewable mandates and goals based on current regulations. The information gained from the survey feeds into the policy needs assessment, where the data is needed to calculate shortfall in the achievement of the renewable requirements of each future due to curtailment. In the 2015 ITP10 Study, SPP Staff assessed the curtailment of all renewable units. If all renewable units within a utility experienced less than 3% curtailment, then the utility had less than 3% renewable curtailment and no further assessment was necessary. Renewable units with greater than 3% curtailment were assessed in further detail. (Attachment 6 – 2017 ITP10 Data Inputs and Methodology)

> **Kip Fox (AEP-Transource) made a motion; seconded by Paul Dietz (WERE) to keep the status quo for the Policy Needs Assessment Methodology. The motion was approved unanimously.**

Kip Fox (AEP–Transource) named Wayman Smith (AEP) as his proxy beginning at 10:00 AM.

Agenda Item 4b – Futures

Kelsey Allen (SPP Staff) began discussion on data inputs and how they would be impacted in a CPP future. The group was shown a variety of potential scenarios to consider, and how the key drivers would be implemented in each of those scenarios. SPP Staff asked the group to think about how certain variables, such as renewable energy, energy efficiency, and unit retirements would change depending on whether the CPP ruling is implemented on a state-by-state or a regional basis.

Discussion began with retirements. Because the inputs to the ITP studies are publically available, members of the ESWG advised against stakeholders providing actual retirements for the study. Also, it was brought up that not every company is involved in the process, and they may not take the opportunity to review the retirement's lists for reasonableness. A threshold could be set so that if a unit provides a large percentage of a company's total generation, then it will not be retired. SPP Staff will continue investigating retiring units based on age or size and bring back to the group.

Energy efficiency has already been included by many companies in their load forecasts. Based on this, some members feel that we could use the current forecast for Futures 1 and 2, and reduce the energy efficiency in Future 3. It was brought up that we need to be able to point out the energy efficiency amounts to be able to take credit for them in the emissions goal computation. Stakeholders were asked to investigate the current energy efficiency included in the current load forecast projections.

Staff is looking also into solar assumptions and is working to develop criteria around solar penetration for different areas.

Closing Items

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

Kelsey Allen (SPP Staff) updated the group on upcoming meetings and locations:

July 9th, 2015: 8th Floor AEP Offices, Dallas, TX

August 19th – 20th, 2015: Magnolia Hotel, Denver, CO

September 23rd, 2015: 8th Floor AEP Offices, Dallas, TX

Kelsey Allen (SPP Staff) reminded stakeholders to look at how energy efficiency was modeled in their area.

There were no official action items from the meeting.

The meeting was adjourned at 11:30 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

SPP Southwest Power Pool

Revision Request Recommendation Report

RR #: 56	**Date:** 8/10/2015
RR Title: Upgrade Determination and Short-Term Reliability Project Process	

SUBMITTER INFORMATION

Submitter Name: Tony Green	**Company:** Southwest Power Pool
Email: tgreen@spp.org	**Phone:** (501)688-1789

EXECUTIVE SUMMARY OF ACTION AND RECOMMENDATION

OBJECTIVE OF REVISION

Describe the problem/issue this revision request will resolve:

Attachment Y of the Tariff describes the categories that determine if a transmission project may be issued to an incumbent Transmission Owner or through the Transmission Owner Selection Process. In order to comply with FERC Order 1000 and Attachment Y of the Tariff, procedures need to be developed to insure that the proper section of the Tariff is used to issue Notifications to Construct.

Describe the benefits that will be realized from this revision.

Compliance with FERC Order 1000 and the SPP Tariff, as well as providing clear communication to stakeholders participating in the process.

IMPACT ANALYSIS REQUIRED: ☐ **Yes** ☐ **No**

Estimated Cost: $ *Cost is a **rough order of magnitude** estimate, approx. +/-50%*	**Estimated Duration:** months *Duration is a **rough order of magnitude** estimate, approx. +/-50%*

Priority Rank for System Change: ☐ **1 – Critical** ☐ **2 – High** ☐ **3 – Medium** ☐ **4 – Low**

SPP DOCUMENTS IMPACTED

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

WORKING GROUP REVIEWS AND RECOMMENDATIONS
List Primary and any Secondary/Impacted WG Recommendations as appropriate

Primary Working Group: BPWG	**Date:** 5/27/2015, 7/29/2015, 8/21/2015 **Action Taken: 5/27/15:** Initial review only. **7/29/15:** 2nd Review. Minor grammatical change. **8/21/15:** Seeking approval. **Abstained:** **Opposed:**

Reason for Opposition:

Secondary Working Group: CTPTF (Primary Secondary)	**Date:** 5/7/2015, 7/30/2015 **Action Taken: 5/7/2015:** Initial review only. **7/30/15**: Review and changes made; motion to approve with changes contingent on no significant changes by other working groups/task forces. Vote: Unanimously approved. **Abstained:** 0 **Opposed:** 0
Reasons for Opposition:	
Secondary Working Group: PCWG	**Date:** 6/3/2015, 8/5/2015 **Action Taken: 6/3/15:** Initial review only; requested changes applied. **8/5/15:** Review and changes made; motion to approve with changes. Vote: Unanimously approved. **Abstained:** 0 **Opposed:** 0
Reasons for Opposition:	
Secondary Working Group: ORWG	**Date:** 8/6/2015 **Action Taken:** Reviewed; no changes. Vote: Unanimously approved. **Abstained:** 0 **Opposed:** 0
Reasons for Opposition:	
Secondary Working Group: ESWG	**Date:** 7/9/2015, 8/19/2015 **Action Taken: 7/9/15:** Initial review only; change made to specify that economic and public policy changes not in STR Project Process. **8/19/15:** Seeking approval. **Abstained:** **Opposed:**
Reasons for Opposition:	
Secondary Working Group: TWG	**Date:** 7/22/2015, 8/19/2015 **Action Taken: 7/22/15:** Initial review only. **8/19/15:** Seeking approval. **Abstained:** **Opposed:**
Reasons for Opposition:	

Secondary Working Group: RTWG	**Date:** 7/23/2015, 8/27/2015 **Action Taken: 7/23/15:** Initial review only. Minor changes suggested and applied for posting for BPWG on 7/29 and CTPTF on 7/30. **8/27/15:** Seeking approval. **Abstained:** **Opposed:**
Reasons for Opposition:	
MOPC	**Date:** October 2015 **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
BOD/Member Committee	**Date:** October 2015 **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	

COMMENTS

Comment Author: David Kayes, OG&E

Description of Comments:

This revision request does not describe "what the problem is or what needs fixing". In the "Objective" section the author immediately describes what the new solution and makes no mention of what the problem is. This request should either be revised to describe the problem (as directed) or rejected as incomplete.

Status: Objective corrected in separate comment form.

Comment Author: Sherri Maxey, SPP staff

Description of Comments: Minor grammatical changes for RR56.

Changes to the "Objectives of Revision Request:" section, as follows:

Describe the problem/issue this revision request will resolve:

Attachment Y of the Tariff describes the categories that determine if a transmission project may be issued to an incumbent Transmission Owner or through the Transmission Owner Selection Process. In order to comply with FERC Order 1000 and Attachment Y of the Tariff, procedures need to be developed to insure that the proper section of the Tariff is used to issue Notifications to Construct.

Describe the benefits that will be realized from this revision.

Compliance with FERC Order 1000 and the SPP Tariff, as well as providing clear communication to stakeholders participating in the process.

Status: Changes applied.
Comment Author: Sherri Maxey, SPP staff
Description of Comments (1) Updates to process flowcharts per PCWG feedback and added process flow for Short-Term Reliability Project Process; and (2) Internal SPP staff changes after legal review.
Status: Changes applied.
Comment Author: Dennis Reed and SPP staff
Description of Comments The RR as written does not accurately reflect the Tariff. A project is assigned to a DTO either through the ITO or the TOSP process. The qualification of a project as an STR only switches the process of determining the DTO from TOSP to ITO. In addition there is no reason to take an upgrade through the STR process if it already qualifies to have the DTO determined through the ITO process. I will also note the STR process was intermixing the approval and posting of the STR report with the approval of an upgrade to be designated as a STR. If the STR report has more than one upgrade described in it, then the process required the Board to approve all the upgrades as STRs or none of them. My edits are to make the process clearer and conform to the approved Tariff language. **SPP Comment** Internal SPP staff made minor changes and would like to clarify comments in (3) above: A project is either assigned to the ITO or selected through the Transmission Owner Selection Process (TOSP). The qualification of a project as a STR Project only switches the process of assigning the project to the ITO, rather than through the TOSP. In addition, only a project that would qualify for the TOSP could be subject to the STR Project process. Changes per ESWG to STR Project Process to specify that economic and public policy projects are not considered in the STR Project process.
Status: Changes applied with modifications.
Comment Author: CTPTF 7/30/15 Teleconference

Description of Changes:

- In first paragraph, added ("ITO") in the second sentence, prior to "; or (2)"
- Under "Upgrade Determination" section, replace verbiage in bullet 6 with Tariff language from Attachment Y, Section I(2) of the SPP Tariff, modified as follows:

  "For transmission projects involving both a Rebuild of existing facilities and the construction of new transmission facilities, SPP shall determine which Tariff process is used to select TO(s), as follows:

  - If 80% or more of the total cost of a project consists of the Rebuild of existing facilities, the upgrade will be designated to the ITO in accordance with Section IV of this Attachment Y;
  - Otherwise, the project will be divided into two or more segments or upgrades, based upon whether that portion of the project is a Rebuild of existing facilities or new facilities. For those segments that are Rebuilds of existing facilities, the upgrade will be designated to the ITO in accordance with Section IV of this Attachment Y. For those segments that are new facilities and determined to be a Competitive Upgrade, those upgrades will be designated pursuant to the TOSP in accordance with Section III of this Attachment Y.
  - Figure 2 below illustrates upgrade determination for projects with new and Rebuild portions.

- In the paragraph following the last bullet under the "Upgrade Determination" section, changed first sentence to: "For transmission facilities that meet the above requirements to be a Competitive Upgrade, but are required to be in service within three (3) years or less to address an identified reliability violation, may be exempted from the TOSP if approved by the Board."
- Modify title of Figure 2 graphic to "Upgrade Determination for Projects with New and Rebuild portions" and keep "Figure 2" graphic.
- In the first bullet under the STR Project Process section, delete "through the Integrated Transmission Planning ("ITP") or high priority study processes by the Board." In that same bullet, add "or less based on the RTO Determined Need Date" prior to the last sentence.
- Modify Figure 3 graphic to show last decision diamond have the text of "Did the SPP Board approve the STR Project?" Also, have "No" going to TOSP process and "Yes" continuing on to the actions in the light blue box.

Status: Changes applied and unanimously approved.

Comment Author: PCWG 8/5/15 Teleconference

Description of Changes:

- 4th bullet under Upgrade Determination section: note added "Approved by FERC 8/3/15"
- In the paragraph following the last bullet under the "Upgrade Determination" section, changed to delete the first word of first sentence, "For" and replace last word in paragraph "below" with the word "section." The paragraph now reads: "Transmission facilities that meet the requirements to be a Competitive Upgrade, but are required to be in service within three (3) years or less to address an identified reliability violation, may be exempted from the TOSP if approved by the Board. Details of this process are described in the STR Project Process section."
- Figures 1, 2 and 3: The blue color was lightened in the decision diamonds for readability.
- RTO Determined Need Date is not a Tariff-defined term, so capitalization removed.
- In the 4th bullet under STR Project Process section, added an "s" to the word "Market."

Status: Changes applied and unanimously approved.

PROPOSED REVISION(S) TO SPP DOCUMENTS
SPP Business Practices

Upgrade Determination and Short-Term Reliability Project Process

Business Practice

This business practice outlines the procedures SPP utilizes to determine which Tariff process is used to select a Transmission Owner ("TO") for upgrades approved by the SPP Board of Directors ("Board") for construction. The two (2) processes utilized include whether an upgrade is: (1) assigned to the incumbent TO, as described in Attachment Y, Section IV ("ITO"); or (2) assigned to a Designated Transmission Owner as a Competitive Upgrade using the Transmission Owner Selection Process ("TOSP"), as described in Attachment Y, Section III of the SPP Tariff. In addition, if a Competitive Upgrade meets the qualification as a Short-Term Reliability ("STR") Project, the project may be assigned to an incumbent TO by the Board. The criteria for determining if a transmission upgrade is assigned to an incumbent TO or through the TOSP process is described in Attachment Y, Section I.3 of the SPP Tariff.

Commented [SM1]: Updated per CTPTF 7/30/15.

Upgrade Determination

SPP will use the following checklist to determine what process is used in selection of a TO for upgrades, as outlined in Attachment Y, Section I of the SPP Tariff. A transmission upgrade must satisfy all of the following requirements in order to be a Competitive Upgrade:

- Transmission facilities that are an Integrated Transmission Plan ("ITP") upgrade, high priority upgrade, or Interregional Project.
- Transmission facilities that have a nominal operating voltage greater than 100 kV.
- Transmission facilities that are not a Rebuild of an existing facility. Rebuild is defined in Attachment Y, Section I.2 of the SPP Tariff.
- Transmission facilities that do not alter a TO's use and control of its existing rights-of-way under relevant law or regulations.
- Transmission facilities located where selecting the TO using the TOSP does not violate relevant law.
- For transmission projects involving both a Rebuild of existing facilities and the construction of new transmission facilities, SPP shall determine which Tariff process is used to select TO(s), as follows:
    - If 80% or more of the total cost of a project consists of the Rebuild of existing facilities, the upgrade will be designated to the ITO in accordance with Section IV of this Attachment Y;
    - Otherwise, the project will be divided into two or more segments or upgrades, based upon whether that portion of the project is a Rebuild of existing facilities or new facilities. For those segments that are Rebuilds of existing facilities, the upgrade will be designated to the ITO in accordance with Section IV of this Attachment Y. For those segments that are new facilities and determined to be a Competitive Upgrade, those upgrades will be designated pursuant to the TOSP in accordance with Section III of this Attachment Y.
    - Figure 2 below illustrates upgrade determination for projects with new and Rebuild portions.
- Transmission facilities that are not a Local Transmission Facility.

Commented [SM2]: Pending FERC language; Docket No. ER13-1939

Commented [TCK3]: FERC language in Docket No. ER13-366

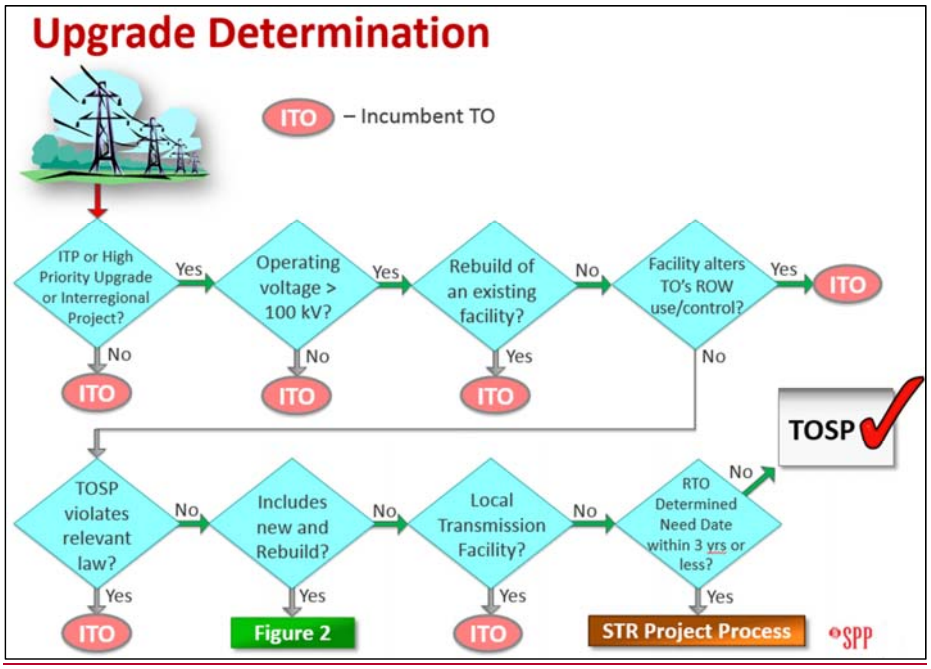
Commented [SM4]: Approved by FERC 8/3/15

Commented [SM5]: New language per CTPTF 7/30/15; slight rewording of Tariff language to fit BP.

Transmission facilities that meet the above requirements to be a Competitive Upgrade, but are required to be in service within three (3) years or less to address an identified reliability violation, may be exempted from the TOSP if approved by the Board. Details of this process are described in the STR Project Process section ~~below~~.

Figures 1 and 2 below illustrate the decision points used in determining which of the two (2) processes itemized above will be utilized in determining whether an upgrade is a Competitive Upgrade subject to the TOSP or designated to the incumbent TO.

Figure 1:



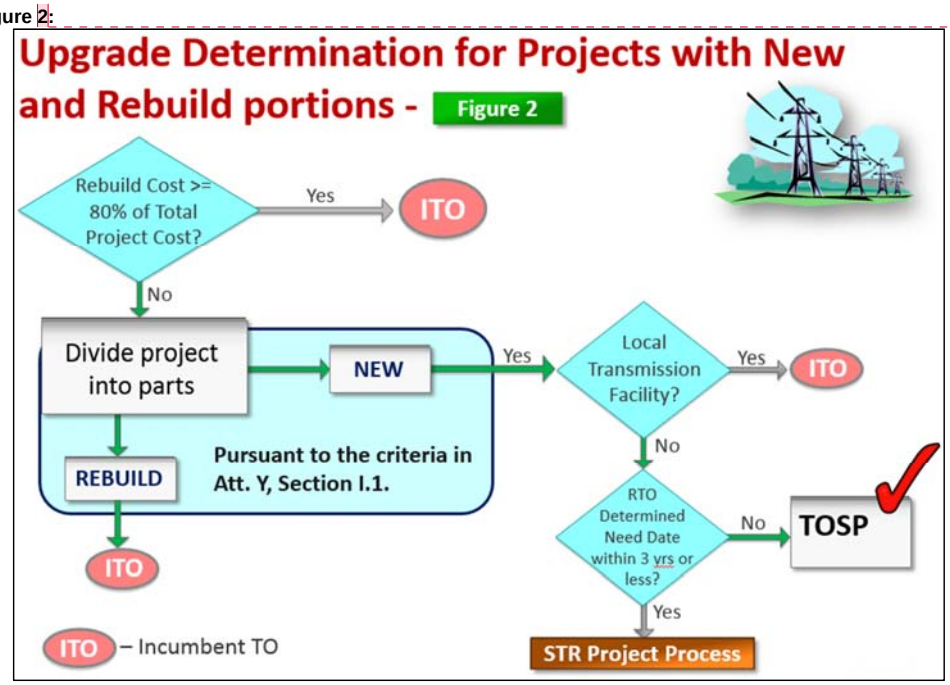
Commented [SM6]: Updated per PCWG 8/5/15

Commented [SM7]: Updated per CTPTF 7/30/15

Commented [SM8]: Change per PCWG 8/5/15

Commented [SM9]: Figures 1, 2 and 3 lightened the colors used with the graphics for readability.

Figure 2:



Designation to Incumbent TO

If an upgrade does not satisfy the requirements to be a Competitive Upgrade, the upgrade will be designated to the incumbent TO as described in Attachment Y, Section IV of the SPP Tariff, and SPP Business Practice 7060.

Designation Pursuant to TOSP

If an upgrade is determined to be a Competitive Upgrade, the Competitive Upgrade will be designated pursuant to the TOSP as described in Attachment Y, Section III of the SPP Tariff, and SPP Business Practice 7700.

STR Project Process

For any reliability upgrade that would otherwise have the TO assigned through the TOSP be considered a STR Project, as defined in Attachment Y, Section I of the SPP Tariff, SPP staff will:

- Identify the time-sensitive needs and post an explanation (the "STR Project Report") on the SPP website pursuant to Attachment Y, Section I of the SPP Tariff, once an upgrade is approved for construction ~~through the Integrated Transmission Planning ("ITP") or high priority study~~ processes ~~by the Board~~. To qualify as a STR Project, the upgrade must have (1) qualified to have the TO assigned through the TOSP process, (2) be required to be constructed to solve a reliability issue, and (3) be required to be in service within three (3) years or less based on the RTO determined need date. Economic and public policy projects are not considered in the STR Project Process.

Commented [SM10]: Updated Figure title per CTPTF 7/30/15

Commented [SM11]: Do both Boards have to approve for interregional projects? **Yes.** Pending FERC language; Docket No. ER13-1939.

Commented [SM12]: Updated per CTPTF 7/30/15
Also, PCWG 8/5/15 – RTO determined need date not a Tariff term so capitalization removed.

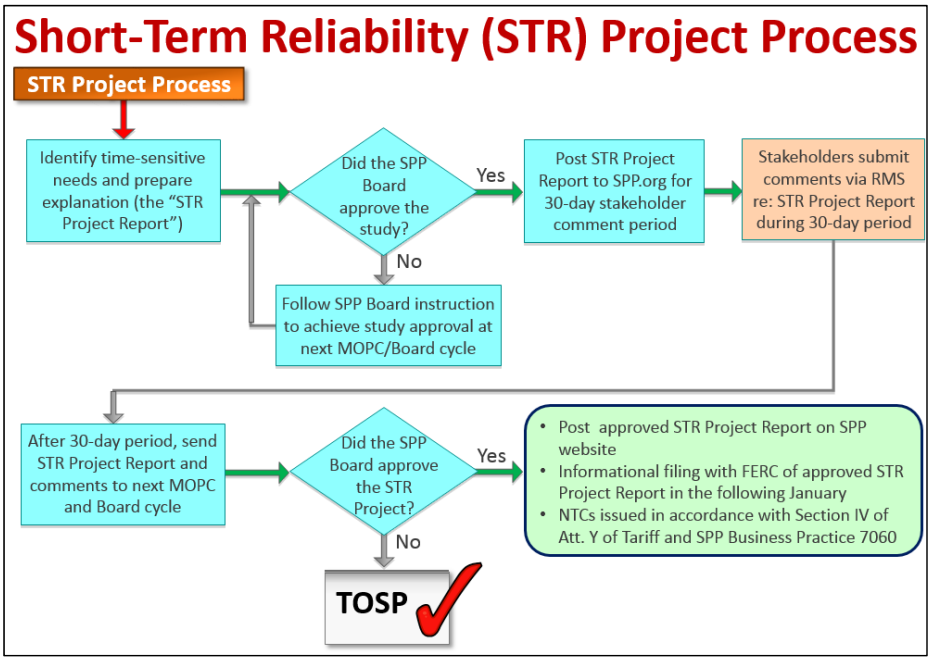
- The STR Project Report will contain at least the following information for each upgrade contained in the report: (1) a description of each upgrade, (2) demonstrate why each upgrade is needed within the three (3) year reliability window and (3) why the upgrade was not identified earlier. Notification of when the report is posted will be sent via email exploder.
- Once the STR Project Report is posted and notification sent out, stakeholders will have a 30 day period in which to provide comments regarding whether or not the project(s) described in the report should be classified as a STR Project. Those comments will be received via the SPP Request Management System ("RMS"), with the instructions provided in the notice posting.
- After the 30-day period, the STR Project Report and comments will be sent to the Markets and Operations Policy Committee ("MOPC") and Board for their review and approval at the next quarterly meeting. The Board may approve one or more upgrades from the report as a STR Project.
- The approved STR Project Report and comments will be stored on the SPP website including those upgrades that were approved as a STR Project.
- The approved STR Project Report, and list of upgrades designated as a STR Project will be filed with FERC as an informational filing in the following January.
- If the Board approves an upgrade as a STR Project, a Notification to Construct ("NTC") will be issued in accordance with Attachment Y, Section IV of the SPP Tariff, and SPP Business Practice 7060.
- If the Board does not approve an upgrade as a STR Project, then SPP shall initiate the TOSP process in accordance with Attachment Y, Section III of the SPP Tariff and SPP Business Practice 7700.

Figure 3 below illustrates the STR Project Process.

Commented [SM13]: Added "s" per PCWG 8/5/15.

Figure 3:

Commented [SM14]: Updated per CTPTF on 7/30/15



Competitive Upgrade Transmission Report

The Competitive Upgrade Transmission Report is a report issued by SPP no later than seven (7) calendar days following the approval of one (1) or more Competitive Upgrade by the Board, which shall provide general information regarding the approved Competitive Upgrades.

This report will include the following items (See Figure 4 – Draft Competitive Upgrade Transmission Report):

- Competitive Upgrade description;
- State(s) in which project is to be built;
- Study Name from which Competitive Upgrade was issued;
- Need date(s) from Board-approved study;
- Anticipated financial expenditure date;
- Expected Request for Proposal ("RFP") issue date;
- Expected RFP Response Window; and
- Indication if Competitive Upgrade(s) have an associated Detailed Project Proposal ("DPP").

Figure 4:

Competitive Upgrade Transmission Report - January 2015

Upgrade Description	State	Study	Study Need Date	Anticipated Financial Expenditure Date	Latest RFP Issue Date	RFP Response Window	Eligible DPPs?
Sample project #1	KS	2015 ITP10	7/1/2019	7/1/2016	1/1/2015	180 Days	Y

ITP - Integrated Transmission Planning
RFP - Request for Proposal
DPP - Detailed Project Proposal

This report will be posted on the SPP website.

Market Protocols

Tariff (OATT)

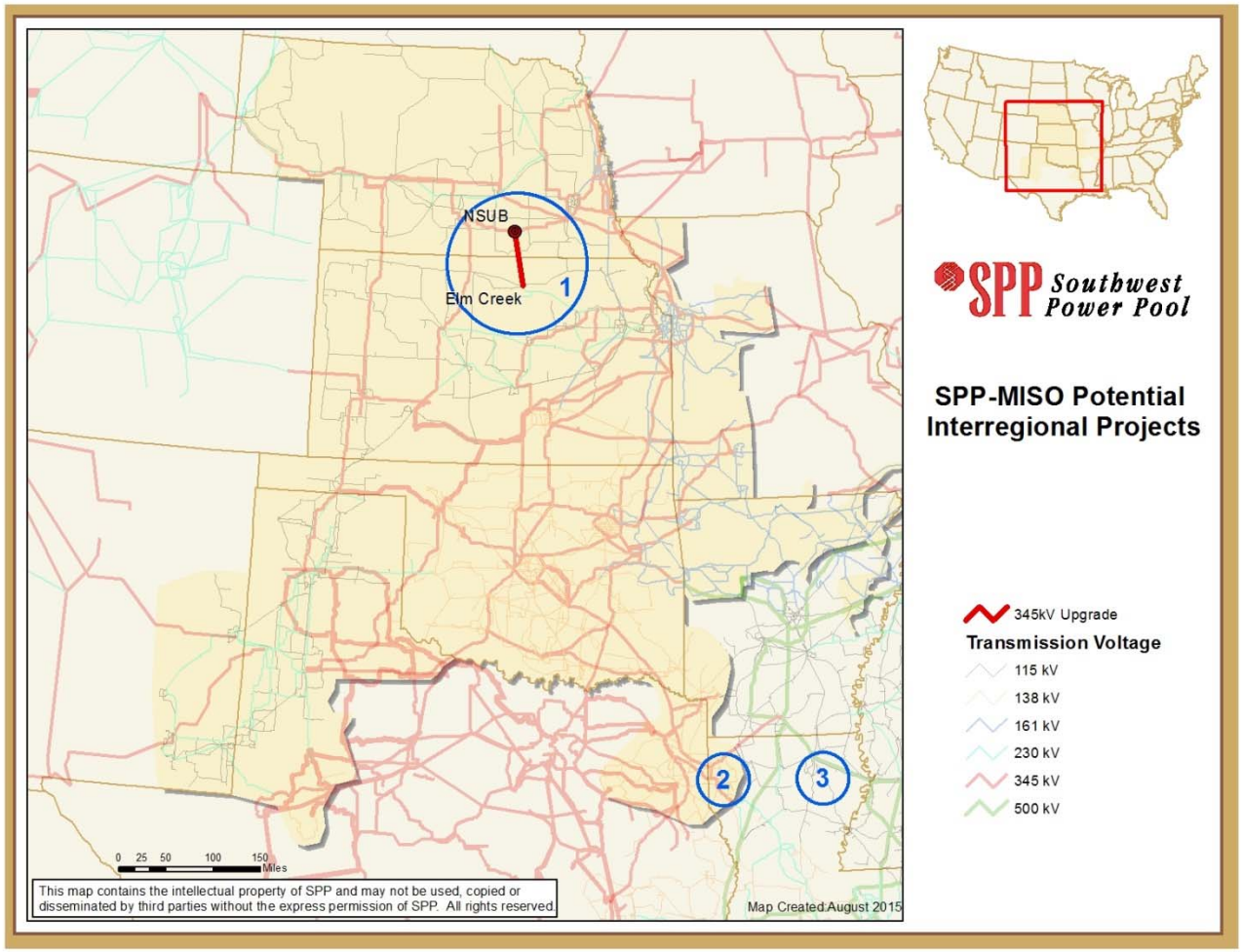
SPP Criteria

Regional Review Preliminary Results

Clayton Mayfield

August 19, 2015

CSP Recommended Economic Projects



1. New 78 mile 345kV from Elm Creek – NSUB (New Substation on the Pauline – Mark Moore 345kV line)
2. Rebuild existing 11 mile South Shreveport to Wallace Lake 138kV line
3. Addition of a series reactor on the Swartz-Alto 115kV line a the Alto 115kV Substation

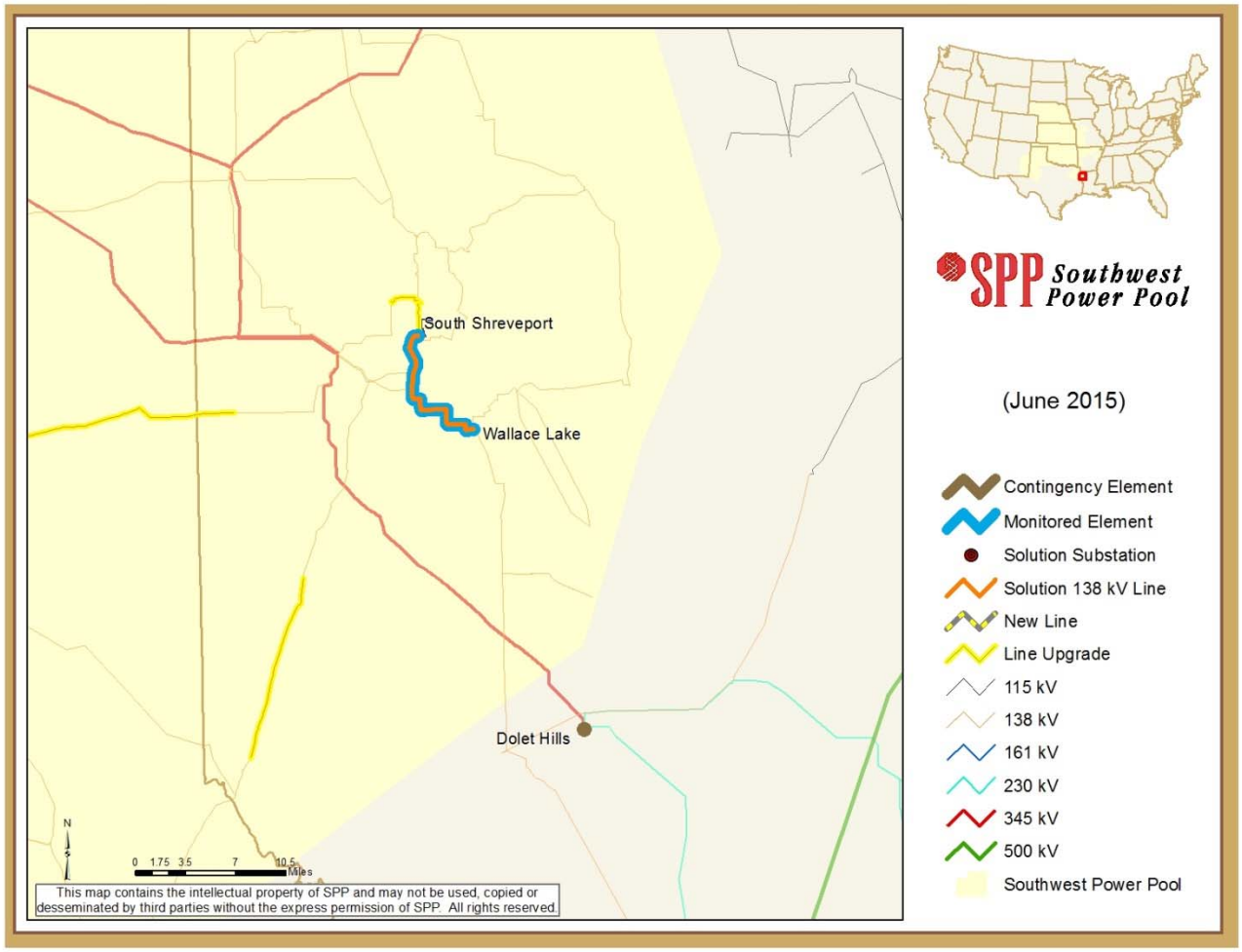
2015 ITP10 Re-evaluated NTCs

- Voltage conversion of Iatan-Stranger Creek 161kV line to 345kV
  - E&C cost (2015$): $37.51M
  - E&C cost increase (2015$): $21.39M
- Rebuild existing 11 mile South Shreveport to Wallace Lake 138kV line
  - E&C cost (2015$): $18.55M
  - E&C cost increase (2015$): $8.23M

Major CSP Model Changes (RR Model)

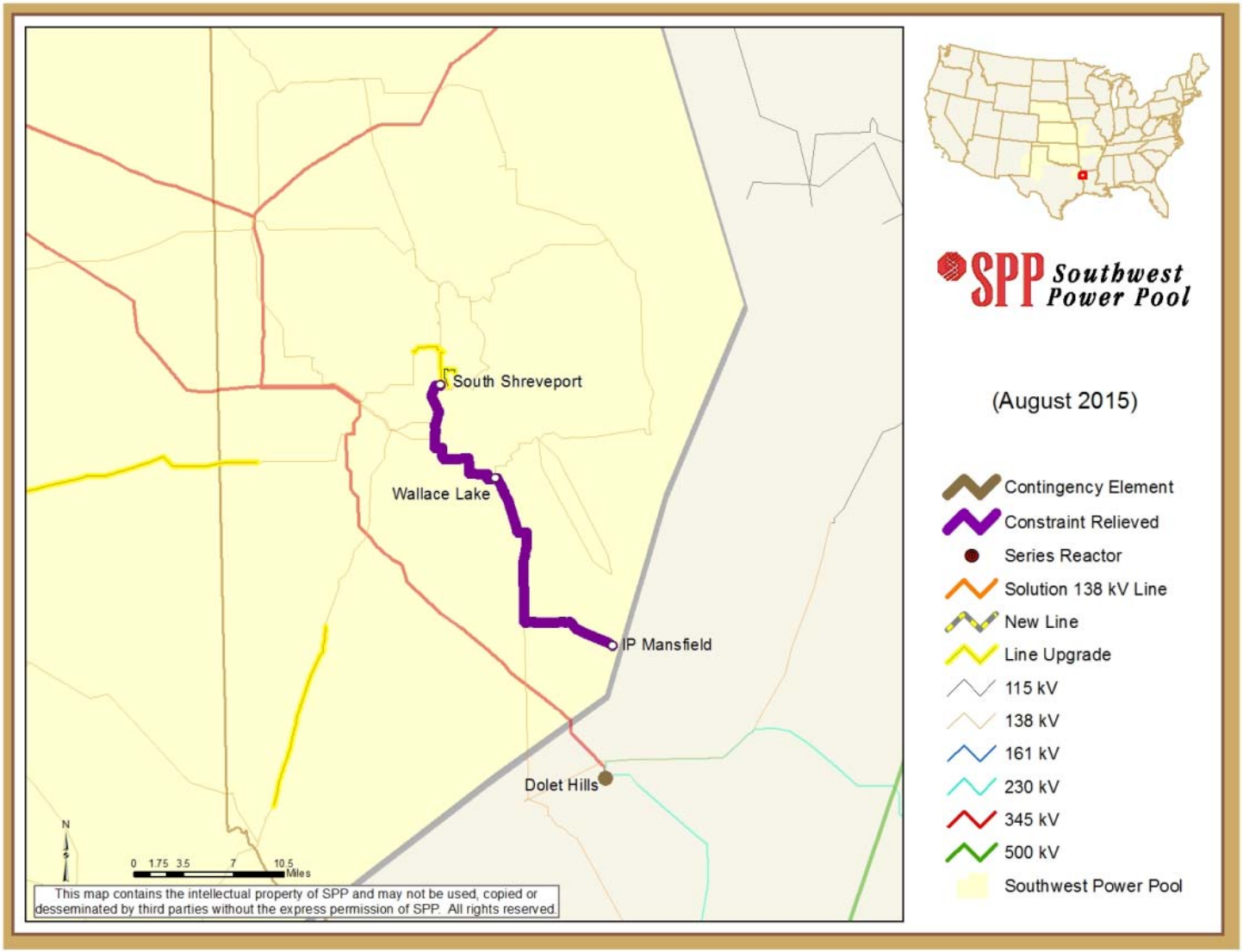
- Included 2017 ITP10 MDWG Updates
  - Retirements, max cap changes, ownership changes, etc.
- Included 2015 ITP10 NTCs in 2019 & 2024 power flow
  - Reliability and economic
  - Included MISOs out of cycle 500kV South Louisiana project
    - Included new 500kV lines plus an additional 571MW of load
- New constraints added from constraint assessment
- Northwestern Energy (NWPS) included in IS pricing zone

S Shreveport – Wallace Lake 138 kV Rebuild



- 20% SPP Funded
- E&C SPP Cost (2024$): $4.63M
- 1 Year SPP Cost (2024$): $0.78M
- 2019 SPP Benefit: $-0.23M
- 2024 SPP Benefit: $1.33M
- 40 Year SPP Benefit: $46.47M
- 1 Year SPP B/C (2024): 1.69
- 40-Year SPP B/C Ratio: 7.28

S Shrev.–Wallace Lake Reb. Relived Constraints



S Shreveport – Wallace Lake Zonal Benefits

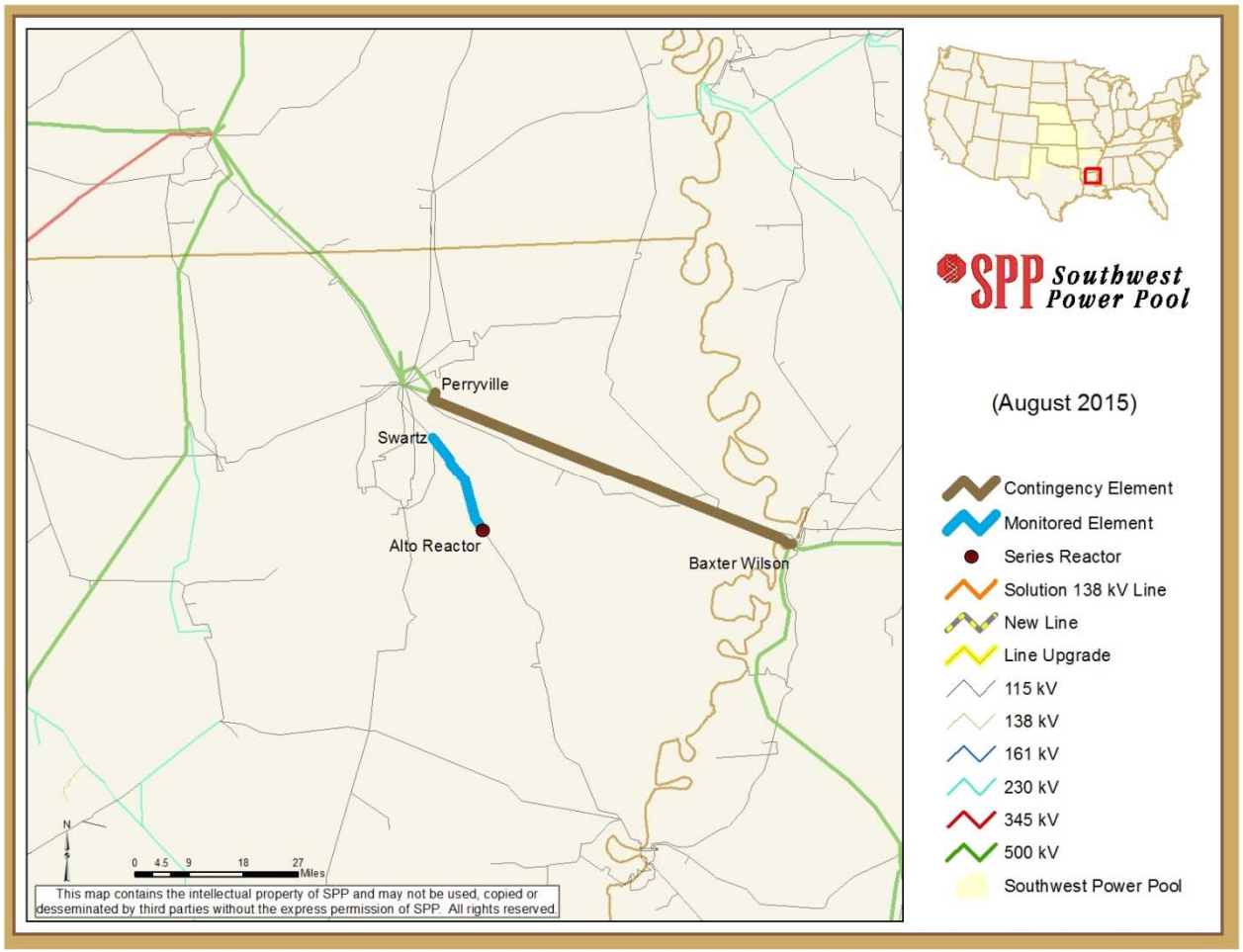
Zone	2019 Benefit ($M)	2024 Benefit ($M)	40 Year NPV Benefit (2015$)	40 Year NPV Cost (2015$)	40-Year B/C
AEPW	($0.0)	$0.6	$17.8	$1.3	13.45
SPCIUT	($0.0)	$0.0	$2.3	$0.1	24.68
EMDE	($0.0)	$0.1	$2.1	$0.2	13.99
GMO	$0.0	$0.2	$5.2	$0.2	21.44
GRDA	($0.0)	$0.1	$3.3	$0.1	27.64
KCPL	$0.0	$0.0	$0.7	$0.5	1.57
LES	$0.0	$0.0	$0.1	$0.1	0.63
MIDW	($0.0)	$0.0	$1.6	$0.0	31.84
MKEC	($0.0)	$0.0	$1.7	$0.1	20.50
NPPD	($0.0)	$0.0	$1.1	$0.4	2.82
OKGE	($0.0)	$0.2	$8.6	$0.8	10.28
OPPD	($0.0)	($0.0)	($0.6)	$0.3	(2.03)
SUNC	$0.0	$0.1	$1.9	$0.1	32.09
SWPS	($0.2)	($0.1)	$1.1	$0.7	1.53
WFEC	$0.0	$0.1	$1.6	$0.2	7.42
WRI	$0.0	($0.1)	($3.5)	$0.7	(5.26)
IS	$0.0	$0.1	$1.6	$0.6	2.84
Total	($0.2)	$1.3	$46.5	$6.4	7.28

S Shreveport – Wallace Lake Rebuild Benefit Across Studies

Study	1-Year B/C (2024)	1-Year Benefit (2024$M)	1-Year Project Cost (2024$M)
2015 ITP10	0.03	$3.93	$1.30
2014 CSP	0.85	$0.45	$0.78
2015 Regional Review	1.69	$1.35	$0.78

- **Leading factors for benefit differences from CSP to Regional Review:**
  - **Out of cycle South Louisiana 500kV Project**
    - **Positively impacts APC benefit attributed to S Shreveport**
  - **Montrose 1, 2, & 3 Retired (510MW)**
    - **Positively impacts APC benefit attributed to S Shreveport**

Series Reactor on Swartz-Alto 115kV



- 14% SPP Funded
- E&C SPP Cost (2024$): $0.92M
- 1 Year SPP Cost (2024$): $0.15M
- 2019 SPP Benefit: $-0.29M
- 2024 SPP Benefit: $-0.46M
- 40 Year SPP Benefit: $-8.33M
- 1 Year SPP B/C (2024): -2.92
- 40-Year SPP B/C Ratio: -6.55

Series Reactor on Alto – Swartz Zonal Benefits

Zone	2019 Benefit ($M)	2024 Benefit ($M)	40 Year NPV Benefit (2015$)	40 Year NPV Cost (2015$)	40-Year B/C
AEPW	$0.1	($0.5)	($17.7)	$0.3	(67.06)
SPCIUT	($0.0)	($0.1)	($1.3)	$0.0	(69.22)
EMDE	$0.0	($0.0)	($0.9)	$0.0	(29.71)
GMO	$0.0	($0.1)	($3.2)	$0.0	(66.79)
GRDA	($0.0)	$0.1	$2.7	$0.0	111.74
KCPL	($0.1)	($0.1)	($0.2)	$0.1	(2.27)
LES	($0.0)	$0.0	$1.2	$0.0	49.31
MIDW	$0.0	($0.0)	($1.0)	$0.0	(98.17)
MKEC	$0.0	($0.0)	($1.7)	$0.0	(101.83)
NPPD	($0.1)	$0.0	$3.8	$0.1	49.34
OKGE	($0.2)	($0.3)	($3.9)	$0.2	(23.64)
OPPD	$0.0	($0.2)	($6.1)	$0.1	(98.72)
SUNC	$0.0	($0.0)	($0.6)	$0.0	(47.17)
SWPS	$0.3	$0.1	($3.4)	$0.1	(23.59)
WFEC	$0.0	$0.1	$2.3	$0.0	52.32
WRI	($0.3)	$0.4	$17.7	$0.1	133.28
IS	($0.1)	$0.1	$4.0	$0.1	36.57
Total	($0.3)	($0.5)	($8.3)	$1.3	(6.55)

Series Reactor on Alto – Swartz

Study	1-Year B/C (2024)	1-Year Benefit (2024$M)	1-Year Project Cost (2024$M)
2014 CSP	1.15	$0.18	$0.15
2015 Regional Review	(2.92)	($0.45)	$0.15

- **Leading factors for benefit differences from CSP to Regional Review:**
  - **Out of cycle South Louisiana 500kV Project**
    - **Negatively impacts APC benefit attributed to series reactor**
  - **Montrose 1, 2, & 3 Retired (510MW)**
    - **Negatively impacts APC benefit attributed to series reactor**

Alto Series Reactor Alternative Evaluation

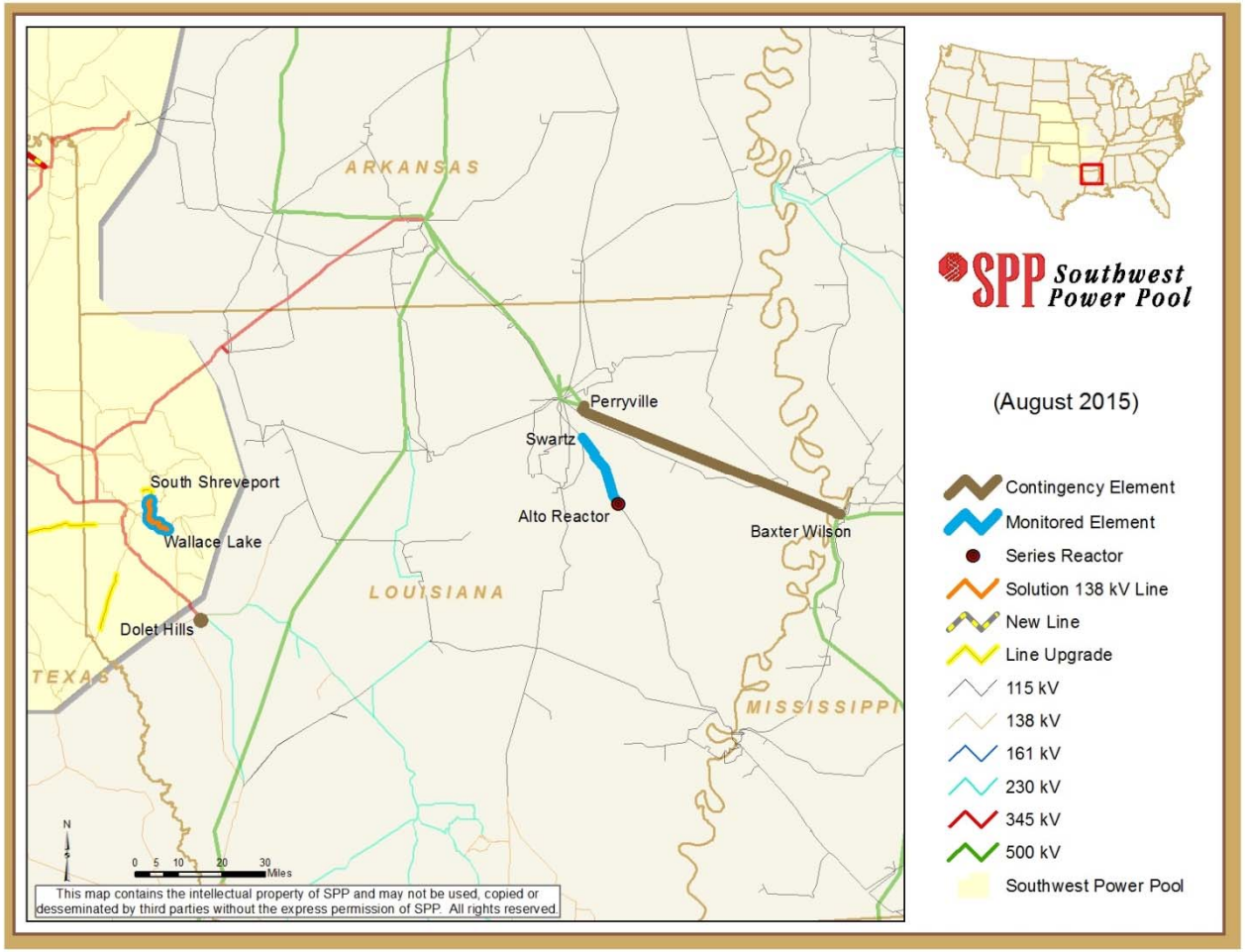
- CSP & RR study the reactor was modeled as fixed
  - During periods Swartz – Alto (161kV) line was not binding/overloaded reactor was in use
  - Molded by tapping the Swartz – Alto (161kV) line and adding the reactors impedance
- Alternative evaluation of reactor as switchable
  - An additional Swartz – Alto (161kV) branch was placed in the model without the series reactor
    - Branch was outaged during binding hours (115MVA and above)
    - Series Reactor branch was outaged during non-binding hours (115MVA and Less)

Alto Series Reactor Alternative Evaluation

Project Description	E&C Cost (2015$)	Nominal ATRR Cost (2015$)	1 Year (2019)	1 Year (2024)		40 Year	
			Benefit (2019$)	Benefit (2024$)	B/C	PV Benefit (2015$)	B/C
Alto Series Reactor	$4,450,914	$7,652,614	-$291,000	-$458,000	-2.92	-$8,334,042	-6.55
Alto Serires Reactor **With** Outage Schedule	$4,450,914	$7,652,614	-$487,000	-$512,000	-3.33	-$6,006,909	-4.72

- Results show that operating the Alto series reactor as fixed instead of switchable results in less benefits
- Benefit for SPP is still negative

Combined S Shreveport – Wallace Lake and Alto Series Reactor

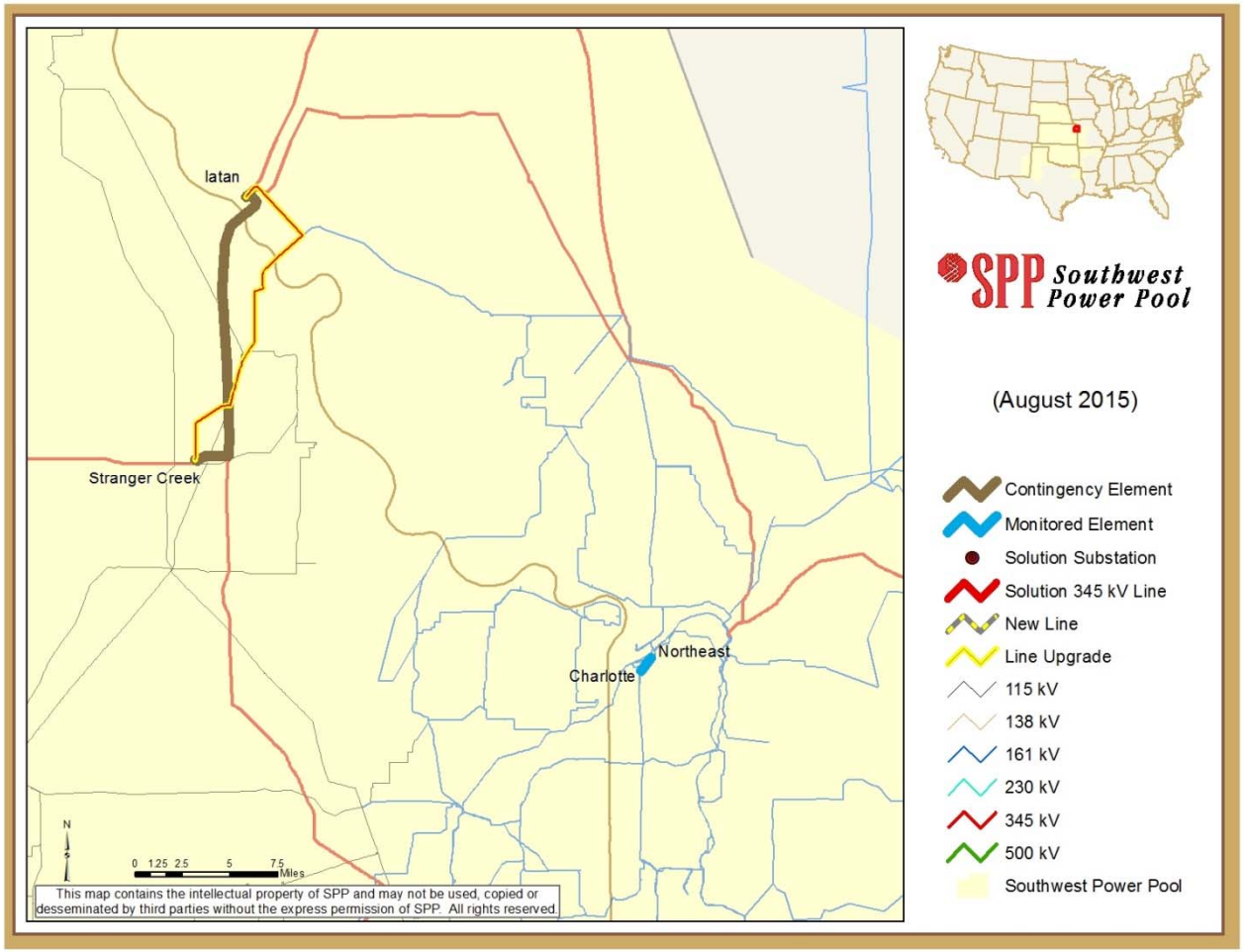


- Alto 14% SPP Funded
- S Shreveport 20% SPP Funded
- E&C SPP Cost (2024$): $5.55M
- 1 Year SPP Cost (2024$): $0.94M
- 2019 SPP Benefit: $-0.52M
- 2024 SPP Benefit: $0.87M
- 40 Year SPP Benefit: $38.14M
- 1 Year SPP B/C (2024): 0.93
- 40-Year SPP B/C Ratio: 4.98

S Shreveport – Wallace Lake with Alto Series Reactor Zonal Benefits

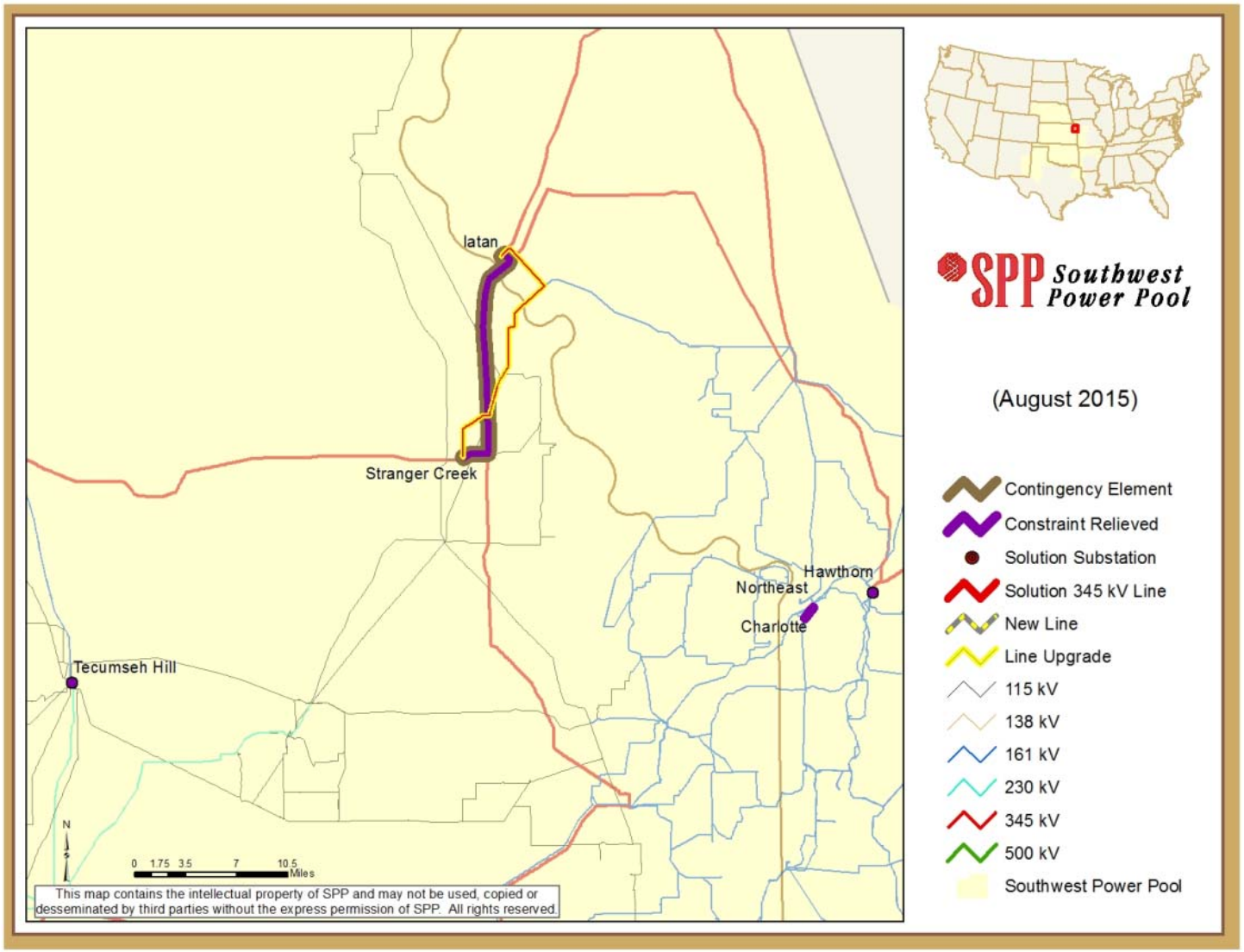
Zone	2019 Benefit ($M)	2024 Benefit ($M)	40 Year NPV Benefit (2015$)	40 Year NPV Cost (2015$)	40-Year B/C
AEPW	$0.1	$0.1	$0.1	$1.6	0.06
SPCIUT	($0.1)	($0.0)	$1.0	$0.1	9.06
EMDE	$0.0	$0.0	$1.2	$0.2	6.72
GMO	$0.1	$0.1	$2.0	$0.3	6.76
GRDA	($0.0)	$0.2	$6.0	$0.1	41.63
KCPL	($0.1)	($0.0)	$0.5	$0.5	0.93
LES	($0.0)	$0.0	$1.3	$0.1	8.73
MIDW	$0.0	$0.0	$0.6	$0.1	10.22
MKEC	$0.0	$0.0	$0.0	$0.1	0.16
NPPD	($0.1)	$0.1	$4.8	$0.5	10.56
OKGE	($0.3)	($0.0)	$4.6	$1.0	4.64
OPPD	($0.0)	($0.2)	($6.7)	$0.4	(18.11)
SUNC	$0.0	$0.1	$1.3	$0.1	18.90
SWPS	$0.1	$0.0	($2.3)	$0.9	(2.65)
WFEC	$0.0	$0.1	$3.9	$0.3	14.89
WRI	($0.3)	$0.3	$14.2	$0.8	17.79
IS	($0.0)	$0.2	$5.6	$0.7	8.45
Total	($0.5)	$0.9	$38.1	$7.7	4.98

Iatan – Stranger Voltage Conversion



- 100% SPP Funded
- E&C SPP Cost (2024$): $46.84M
- 1 Year SPP Cost (2024$): $7.96M
- 2019 SPP Benefit: $12.0M
- 2024 SPP Benefit: $43.9M
- 40 Year SPP Benefit: $1.12B
- 1 Year SPP B/C (2024): 5.51
- 40-Year SPP B/C Ratio: 17.43

Iatan–Stranger Volt Conv. Relived Constraints



Iatan – Stranger Zonal Benefits

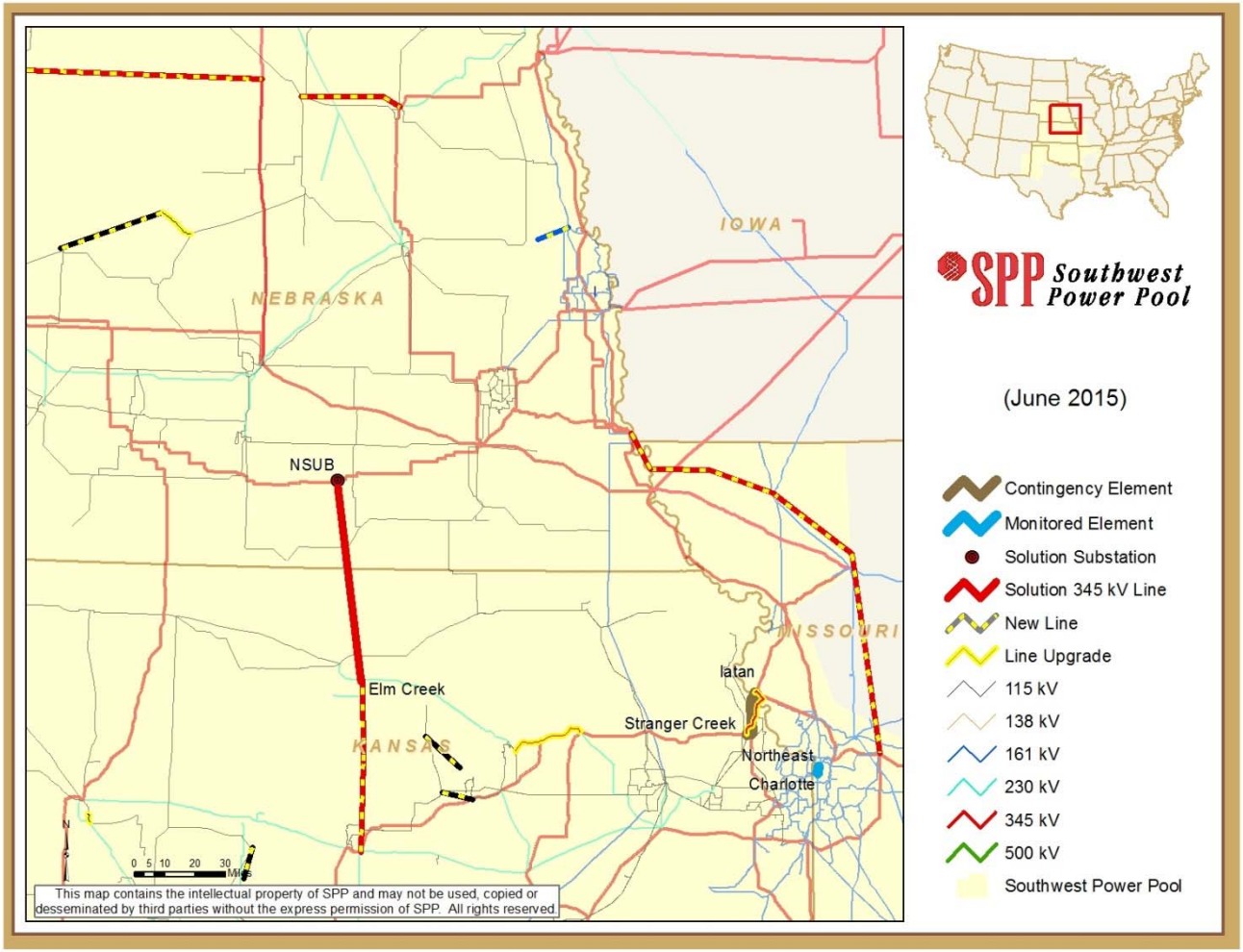
Zone	2019 Benefit ($M)	2024 Benefit ($M)	40 Year NPV Benefit (2015$)	40 Year NPV Cost (2015$)	40-Year B/C
AEPW	$0.6	$3.7	$101.7	$13.3	7.63
SPCIUT	($0.1)	($0.2)	($5.7)	$0.9	(6.14)
EMDE	$0.2	$1.2	$31.0	$1.5	20.29
GMO	($0.5)	($1.8)	($45.0)	$2.5	(18.27)
GRDA	($0.8)	($1.3)	($21.9)	$1.2	(17.95)
KCPL	$4.8	$17.6	$451.6	$4.6	98.97
LES	($0.3)	($1.1)	($27.0)	$1.2	(22.24)
MIDW	$0.2	$0.7	$18.4	$0.5	36.59
MKEC	$0.9	$3.3	$85.4	$0.8	100.71
NPPD	$0.6	$0.7	$10.9	$3.9	2.83
OKGE	$3.0	$5.6	$113.3	$8.4	13.44
OPPD	$0.8	$1.1	$18.3	$3.1	5.86
SUNC	($0.1)	$0.0	$2.2	$0.6	3.67
SWPS	$0.1	$1.2	$35.7	$7.4	4.82
WFEC	$0.3	($1.2)	($45.2)	$2.2	(20.70)
WRI	$2.2	$15.1	$427.2	$6.7	63.42
IS	($0.0)	($0.9)	($26.7)	$5.6	(4.79)
Total	$12.0	$43.9	$1,124.2	$64.5	17.43

Iatan – Stranger Benefit Across Studies

Study	1-Year B/C (2024)	1-Year Benefit (2024$M)	1-Year Project Cost (2024$M)
2015 ITP10	3.66	$29.14	$7.96
2014 CSP	2.48	$19.71	$7.96
2015 Regional Review	5.51	$43.91	$7.96

- **Leading factors for benefit differences from CSP to Regional Review:**
  - **Montrose 1, 2, & 3 Retired (510MW)**
    - **Positively impacts APC benefit attributed to Iatan - Stranger**

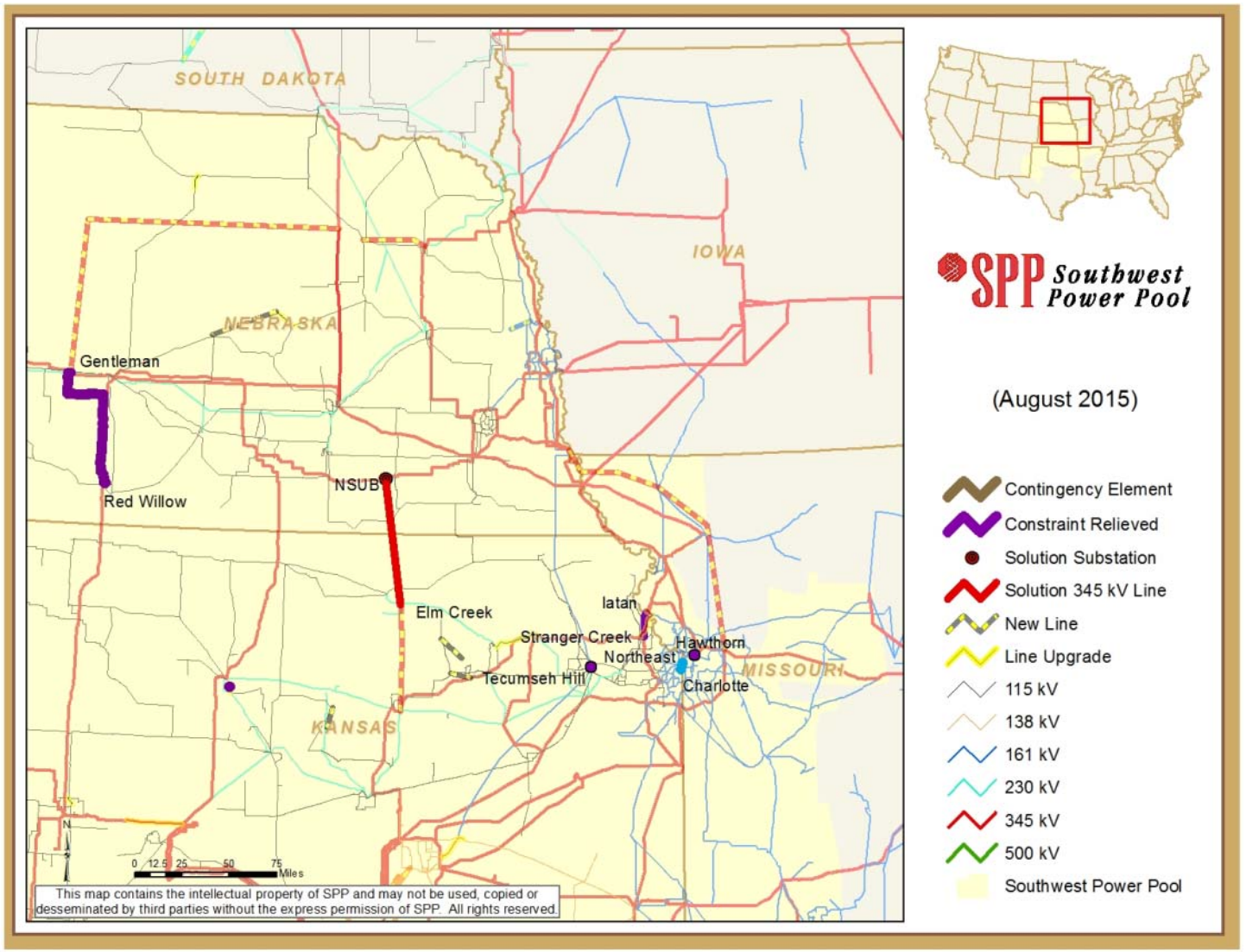
Elm Creek – NSUB



- 80% SPP Funded
- E&C SPP Cost (2024$): $140.5M
- 1 Year SPP Cost (2024$): $23.8M
- 2019 SPP Benefit: $11.2M
- 2024 SPP Benefit: $20.8M
- 40 SPP Year Benefit: $421.8M
- 1 Year SPP B/C (2024): 0.87
- 40-Year SPP B/C Ratio: 2.18

This analysis assumes replacing the Iatan – Stranger project

Elm Creek – NSUB Relived Constraints



Elm Creek – NSUB Zonal Benefits

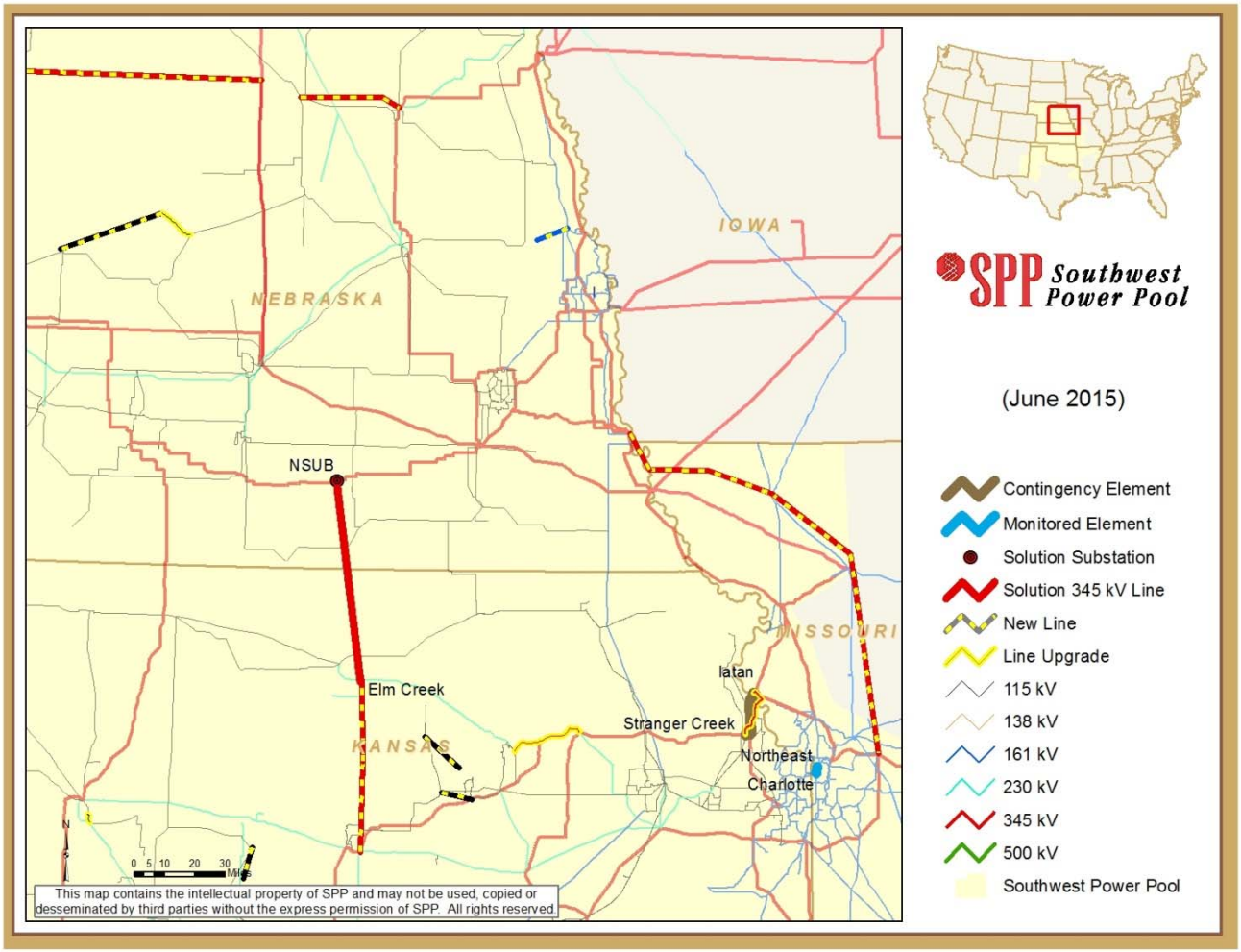
Zone	2019 Benefit ($M)	2024 Benefit ($M)	40 Year NPV Benefit (2015$)	40 Year NPV Cost (2015$)	40-Year B/C
AEPW	$0.3	$1.2	$29.4	$40.0	0.74
SPCIUT	($0.0)	($0.1)	($2.8)	$2.8	(1.01)
EMDE	($0.2)	($0.1)	$0.3	$4.6	0.07
GMO	$0.2	$0.1	($0.4)	$7.4	(0.05)
GRDA	($0.2)	($0.4)	($7.1)	$3.7	(1.95)
KCPL	$0.0	$2.5	$78.4	$13.7	5.73
LES	$0.1	($0.3)	($11.1)	$3.6	(3.05)
MIDW	$0.3	$0.6	$10.0	$1.5	6.63
MKEC	$1.4	$2.6	$50.5	$2.5	19.85
NPPD	$3.8	$5.5	$92.8	$11.6	8.02
OKGE	$2.0	$2.5	$35.5	$25.3	1.40
OPPD	$1.9	$2.3	$32.2	$9.4	3.44
SUNC	$0.2	$0.4	$6.5	$1.8	3.66
SWPS	$0.4	$1.0	$23.1	$22.2	1.04
WFEC	$0.4	($0.3)	($18.0)	$6.6	(2.75)
WRI	($0.0)	$3.7	$116.9	$20.2	5.79
IS	$0.4	($0.2)	($14.4)	$16.7	(0.86)
Total	$11.2	$20.9	$421.8	$193.5	2.18

This analysis assumes replacing the Iatan – Stranger project

Elm Creek – NSUB Benefit Across Studies

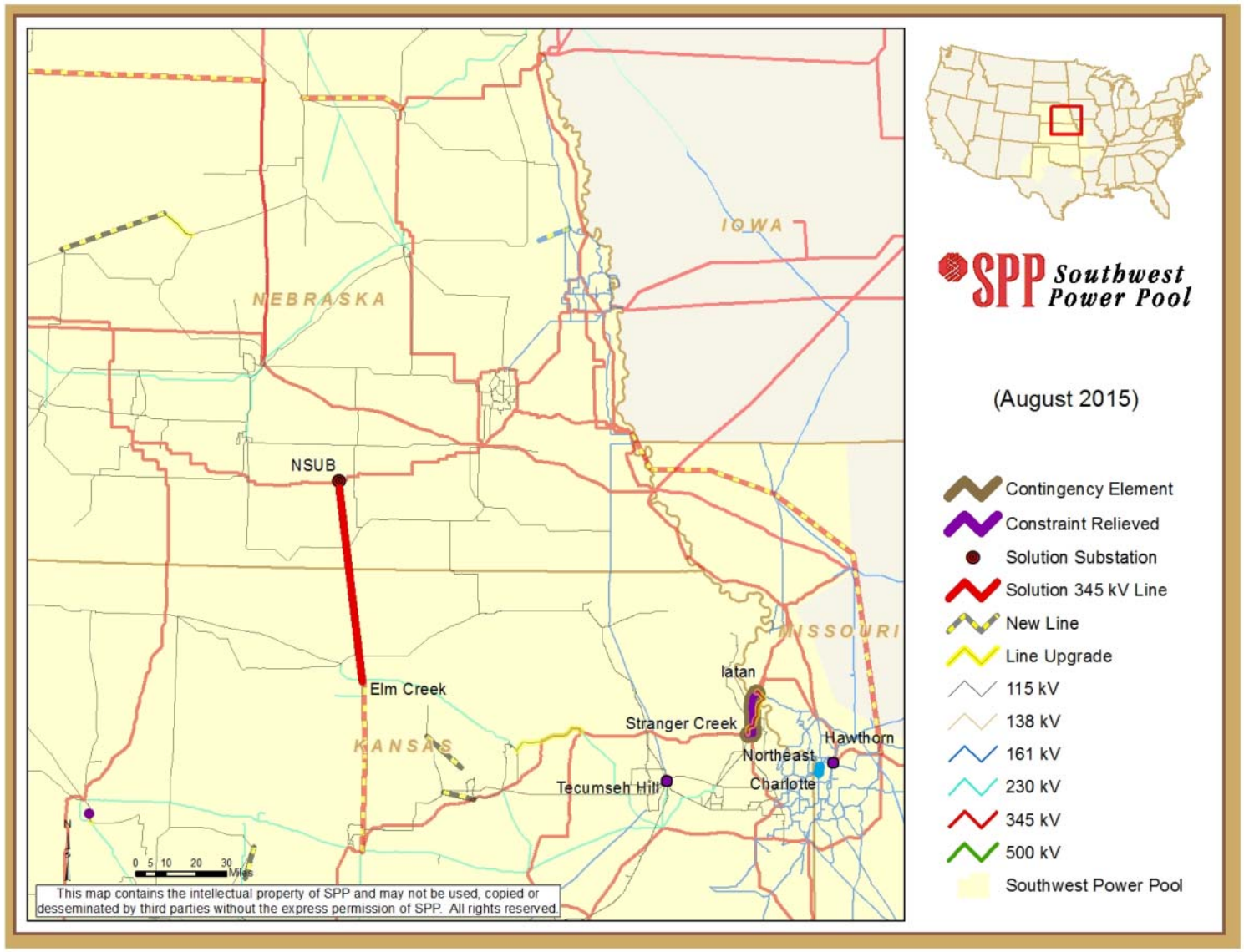
Study	1-Year B/C (2024)	1-Year Benefit (2024$M)	1-Year Project Cost (2024$M)
2015 ITP10	0.67	$20.13	$29.86
2014 CSP	0.79	$18.77	$23.89
2015 Regional Review	0.87	$20.88	$23.89

Elm Creek – NSUB & Iatan – Stranger



- NSUB-Elm Creek 80% SPP Funded
- Iatan-Stranger 100% SPP Funded
- E&C SPP Cost (2024$): $187.3M
- 1 Year SPP Cost (2024$): $31.8M
- 2019 SPP Benefit: $48.8M
- 2024 SPP Benefit: $54.5M
- 40 Year SPP Benefit: $699.9M
- 1 Year SPP B/C (2024): 1.44
- 40-Year SPP B/C Ratio: 2.71

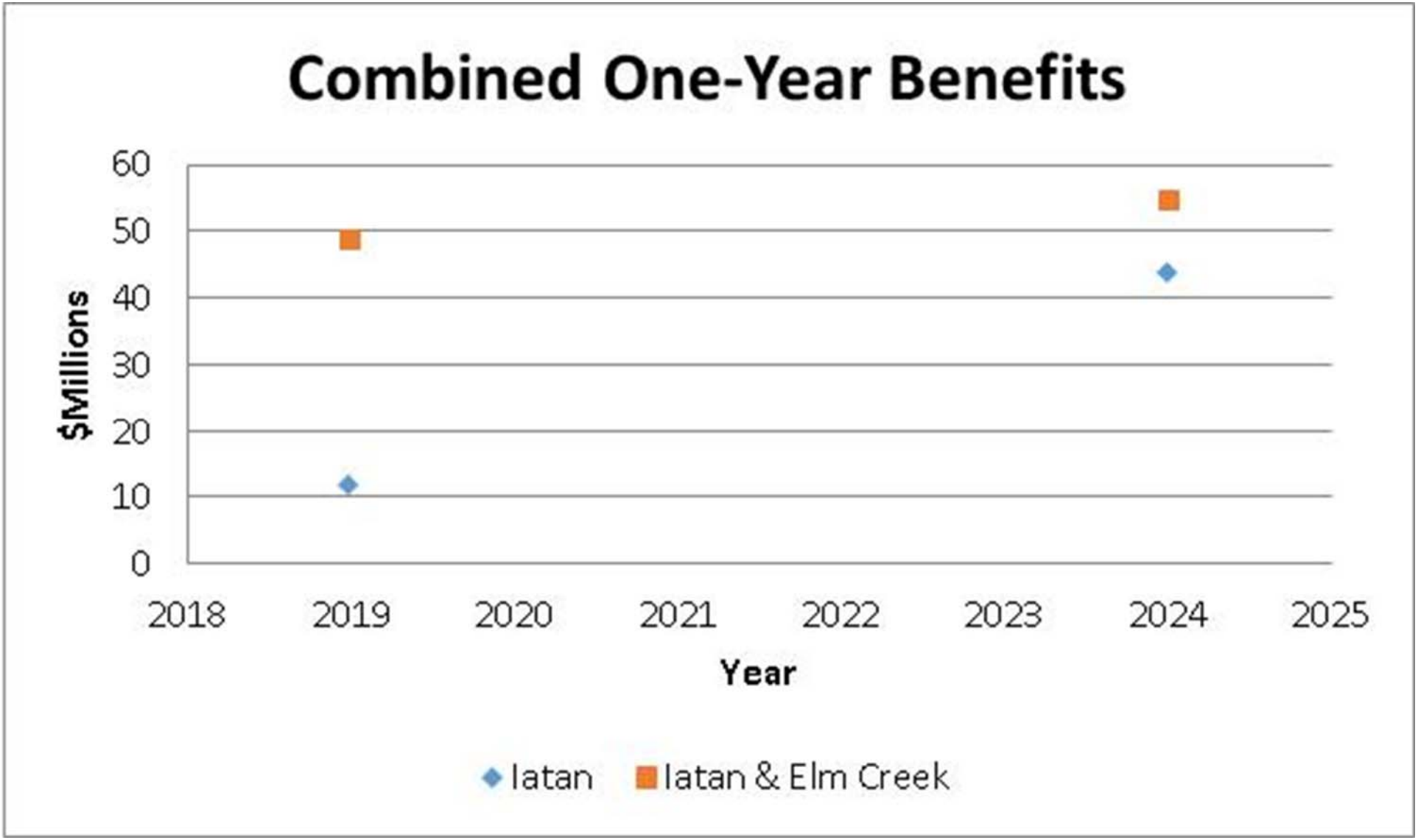
Iatan & Elm Creek Relived Constraints

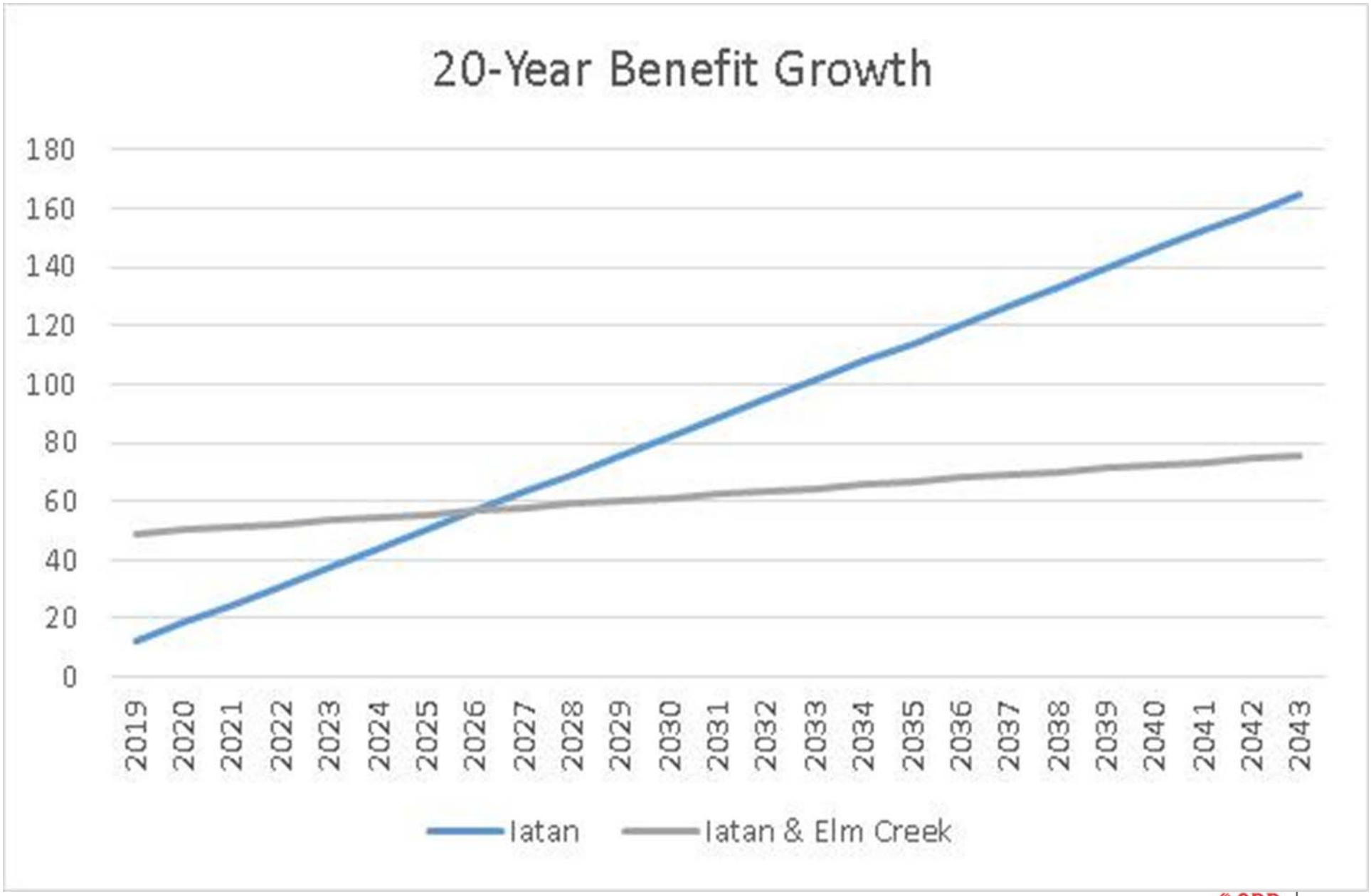


Elm Creek – NSUB & Iatan – Stranger Together

Project	1-Year B/C (2024)	1-Year Benefit (2024$M)	1-Year Project Cost (2024$M)
NSUB-Elm Creek 345kV	0.87	$20.88	$23.89
Iatan-Stranger Volt Conversion	5.51	$43.91	$7.96
NSUB-Elm Creek 345kV & Iatan-Stranger Volt Conversion	1.44	$54.51	$37.82

- **Leading factors for benefit differences:**
  - **Benefit Curve (explained next slides)**


Combined One-Year Benefits
$Millions
60
50
40
30
20
10
0
2018
2019
2020
2021
2022
2023
2024
2025
Year
Iatan
Iatan & Elm Creek


20-Year Benefit Growth
180
160
140
120
100
80
60
40
20
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
Iatan
Iatan & Elm Creek

2019 Value Impact

Concept	Projects	2019 Benefit	2024 Benefit	40-Year Benefit
SCUD/SCED Analysis	Iatan – Stranger	$12 Mil	$44 Mil	$1.1 Bil
SCUD/SCED Analysis	Iatan and Elm Creek	$49 Mil	$55 Mil	$700 Mil
Reduce 2019 Benefit	Iatan & Elm Creek	$15 Mil*	$55 Mil	$1.4 Bil
Increase 2019 Benefit	Iatan – Stranger	$39 Mil^	$44 Mil	$574 Mil

All values are in 2015 dollars

*** Value calculated by reducing the 2019 value by the percentage difference of the 2024 values.**

^ Value calculated by increasing the 2019 value by the percentage difference of the 2024 values

APC Benefits Summary

Project Description	E&C Cost (2015$M)	40 Year NPV Cost (2015$M)	1 Year (2019)	1 Year (2024)		40 Year		
			Benefit (2019$M)	Benefit (2024$M)	B/C	PV Benefit (2015$M)	B/C	Net Benefit (2015$M)
Stranger to Iatan line 161 kV voltage conversion to 345kV	$46.84	$64.49	$12.02	$43.91	5.51	$1,124.20	17.43	$1,059.70
Rebuild the existing 11.18 mile South Shreveport to Wallace Lake 138 kV line	$3.71	$6.37	-$0.23	$1.33	1.69	$46.47	7.28	$40.09
Alto Series Reactor	$0.74	$1.27	-$0.29	-$0.45	-2.92	-$8.33	-6.55	-$9.60
New 78 mile 345kV line from new 345kV sub statoion NSUB to existing Elm Creek sub station	$112.53	$193.47	$11.22	$20.88	0.87	$421.82	2.18	$228.34
New 78 mile 345kV line from new 345kV sub statoion NSUB to existing Elm Creek sub station **AND IATAN**	$159.37	$257.97	$48.89	$54.51	1.44	$700.00	2.71	$441.94
Alto + S Shreveport + Iatan	$4.45	$7.65	-$0.52	$0.87	0.93	$38.14	4.98	$30.48

Wheeling Through and Out Metric Results

- Concept: Increased ATC from transmission projects increases export opportunities for the SPP footprint
- Calculated the increased ATC after adding each interregional project to the Base Case
- ATC Results
  - Elm Creek – NSUB project increased SPP export capabilities by 15.9 MW.
  - The other interregional projects did not increase SPP export capabilities

Wheeling Through and Out Metric Results

Wheeling Benefit$_{2024}$ ($/yr) =

$$\left[\frac{Incremental\ Wheeling\ Revenues\ Collected\ Thru\ 2014\ \left(\frac{2024\ \$}{yr}\right)}{Incremental\ Historical\ TSRs\ Sold\ Thru\ 2014\ (MW)}\right]$$ x Forecasted Additional Service Sold$_{2024}$ (MW)

- **Utilized the Historical Ratio data used in the 2015 ITP10 to forecast the additional service sold in 2024.**

- **Wheeling Benefit$_{2024}$ ($/yr) = $0.6M/yr**

No-Harm Evaluation Results

- Performed ACCC analysis to determine if any new reliability needs were created by the inclusion of any of the Interregional Projects
  - Compared needs list from an initial ACCC run with needs from an ACCC run including the potential interregional projects
  - No additional needs were identified

Iatan – Stranger Creek Re-evaluation

- Utilized the regional review model
  - Included the three potential interregional projects
  - Removed the Iatan – Stranger Creek NTC
- Charlotte – Northeast 161kV line overloaded at 101.7% (flo Crosstown – Grand Avenue West 161kV)

Avoided Reliability Metric

- Leveraged the ACCC Analysis performed for the No-Harm Evaluation to determine if any thermal needs were mitigated by the proposed interregional project(s)
  - South Shreveport to Wallace Lake 138kV – Interregional Project mitigates the need for the South Shreveport to Wallace Lake 138kV – ITP10 Project
  - No other avoided reliability benefit was determined

Summary of Results of Re-evaluation

- Iatan – Stranger voltage conversion still cost effective even with increased construction cost
- S Shreveport to Wallace lake still most cost effective reliability solution even with increased construction cost

Next Steps

- Thorough review of preliminary analysis results
- Incorporate stakeholder feedback
- Present finalized results at September ESWG and TWG along with SPP staff recommendation

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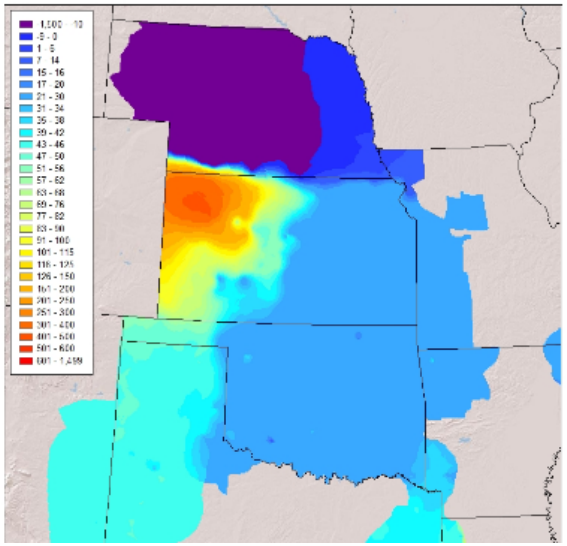
SPP Southwest Power Pool

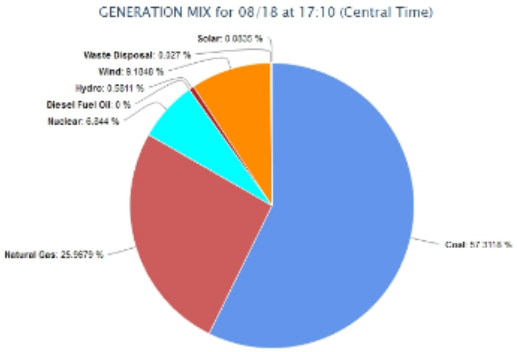
Stakeholder Center | Engineering | Markets & Operations | Regional Entity

Helping our members work together to keep the lights on... today and in the future.

Price Contour Map

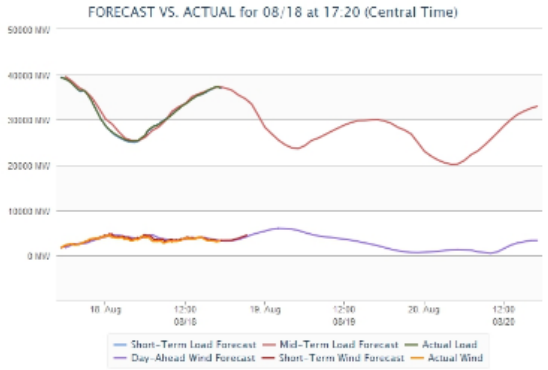


Generation Mix

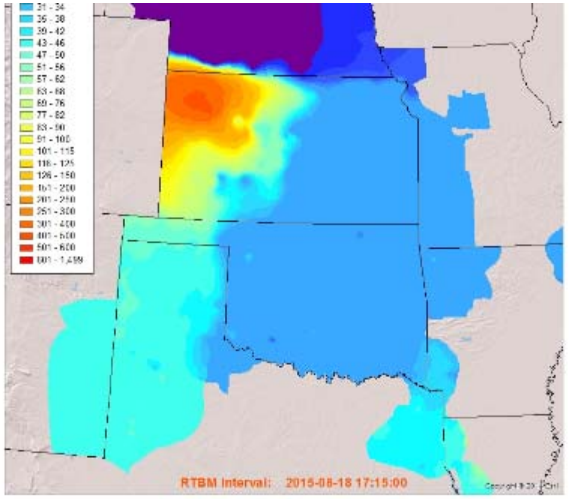


SEE MORE

Forecast vs. Actual



SEE MORE



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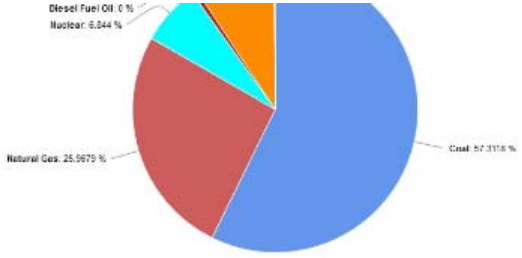

SEE MORE

SEE MORE

CALENDAR of EVENTS

Prev | August 2015 | Next

Sun	Mon	Tue	Wed	Thu	Fri	Sat
26	27	28	29	30	31	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	1	2	3	4	5

Title	Date	Location	
ESWG Meeting	August 19, 2015	Colorado	MORE
ESWG Meeting	August 20, 2015	Colorado	MORE
MWG Meeting	August 20, 2015	Texas	MORE
MWG Meeting	August 21, 2015	Texas	MORE
Made Up Event Display	August 25, 2015		MORE
Made Up Event Display	August 26, 2015		MORE
Made Up Event Display	August 27, 2015		MORE
CWG Meeting	August 25, 2015	Arkansas	MORE
CWG Teleconference	August 28, 2015		MORE

CWG Meeting	August 25, 2015	Arkansas	MORE
CWG Teleconference	August 28, 2015		MORE
PVO Display Title pvo's	August 29-30, 2015		MORE
RLT	September 1, 2015		MORE
RLT	September 1, 2015		MORE
PRC 005-6 FERC Order 803 WebEx	September 8, 2015		MORE

SEE ALL EVENTS

Organizational Groups

Meeting materials, member info, and more.

Documents

Filings, governing documents, and other resources.

News

SPP releases final analysis of draft Clean Power Plan

SPP Southwest Power Pool

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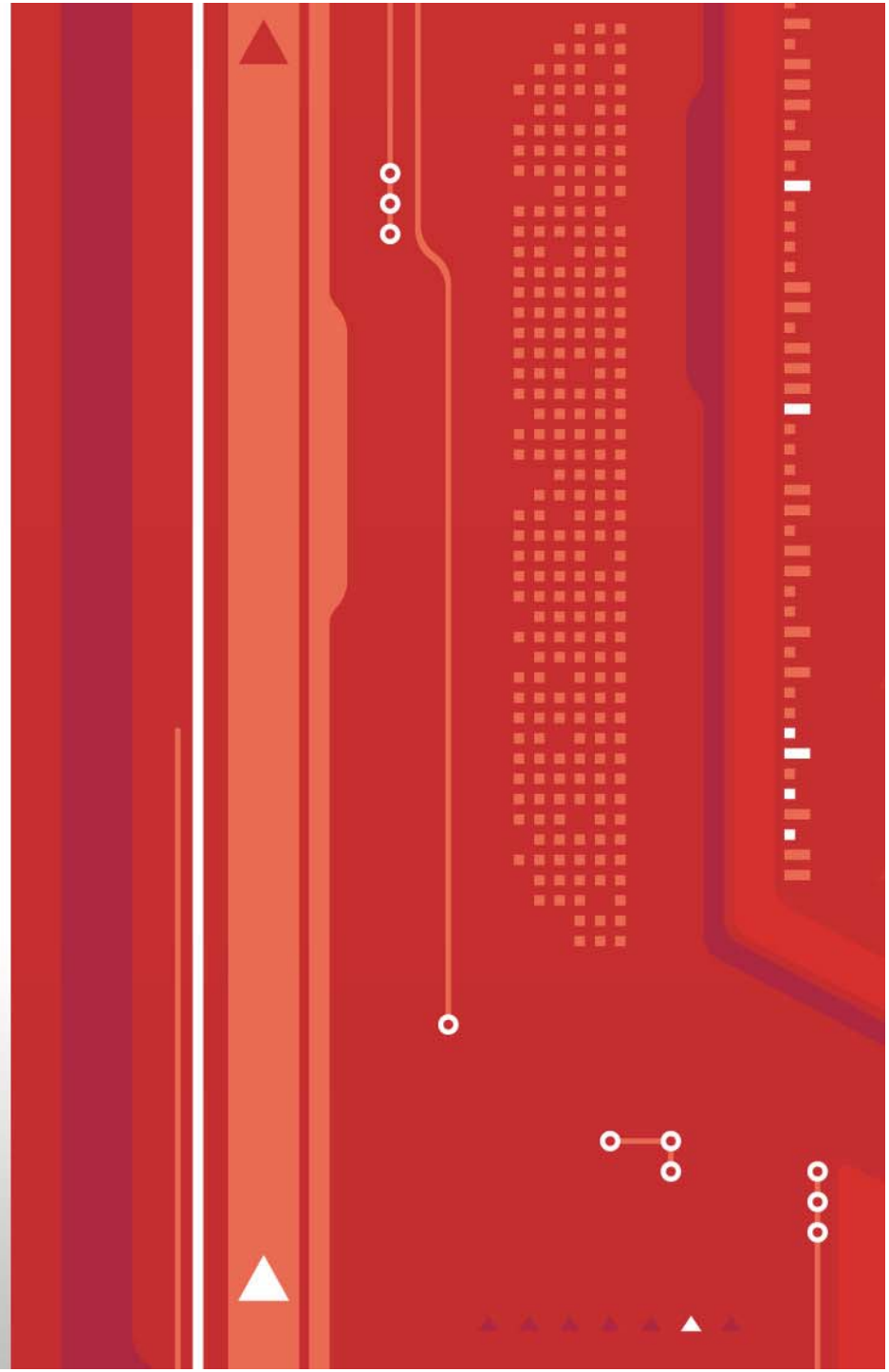
Southwest Power Pool
201 Worthen Drive • Little Rock, AR 72223-4936
(501) 614-3200 • questions@spp.org

Developed by ARISTOTLE

EPA Clean Power Plan – SPP Goal Computation

August 19th, 2015

ESWG



SPP Southwest Power Pool

DRAFT RULE

SPP Emission Goal Estimate

- Use EPA's technical support documents for Best System of Emissions Reduction (BSER)
- Identify SPP portion of each state:
  - Existing Generation Units (EGUs)
  - At-risk nuclear capacity
  - Renewable energy (existing and potential)
    - Excludes existing hydro
  - Energy efficiency
- Regional analysis: determine weighted average CO_2 emissions goal for the SPP region

BSER is Based on Four Building Blocks

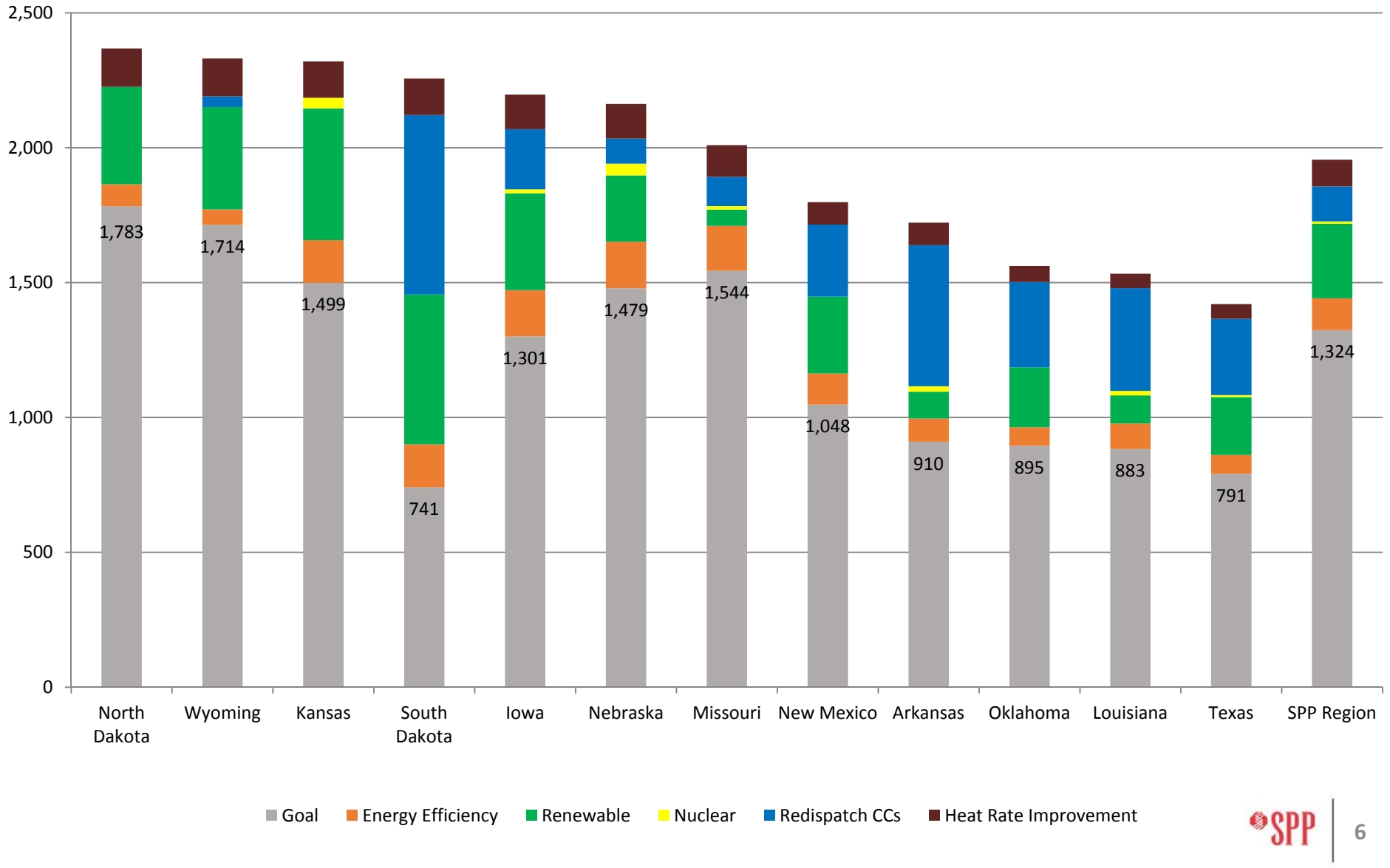
Block	Assumption
1. Improve efficiency of existing coal plants	6% efficiency improvement across fleet, assuming best practices and equipment upgrades
2. Increase reliance on CC gas units	Re-dispatch of Natural Gas CCs up to a capacity factor of 70%
3. Expand use of renewable resources and sustain nuclear power production	Meet regional non-hydro renewable target, prevent retirement of at-risk nuclear capacity and promote completion of nuclear capacity under construction
4. Expand use of demand-side energy efficiency	Scale to achieve 1.5% of prior year's annual savings rate

*Uses 2012 data for existing units and estimated data for units under construction.

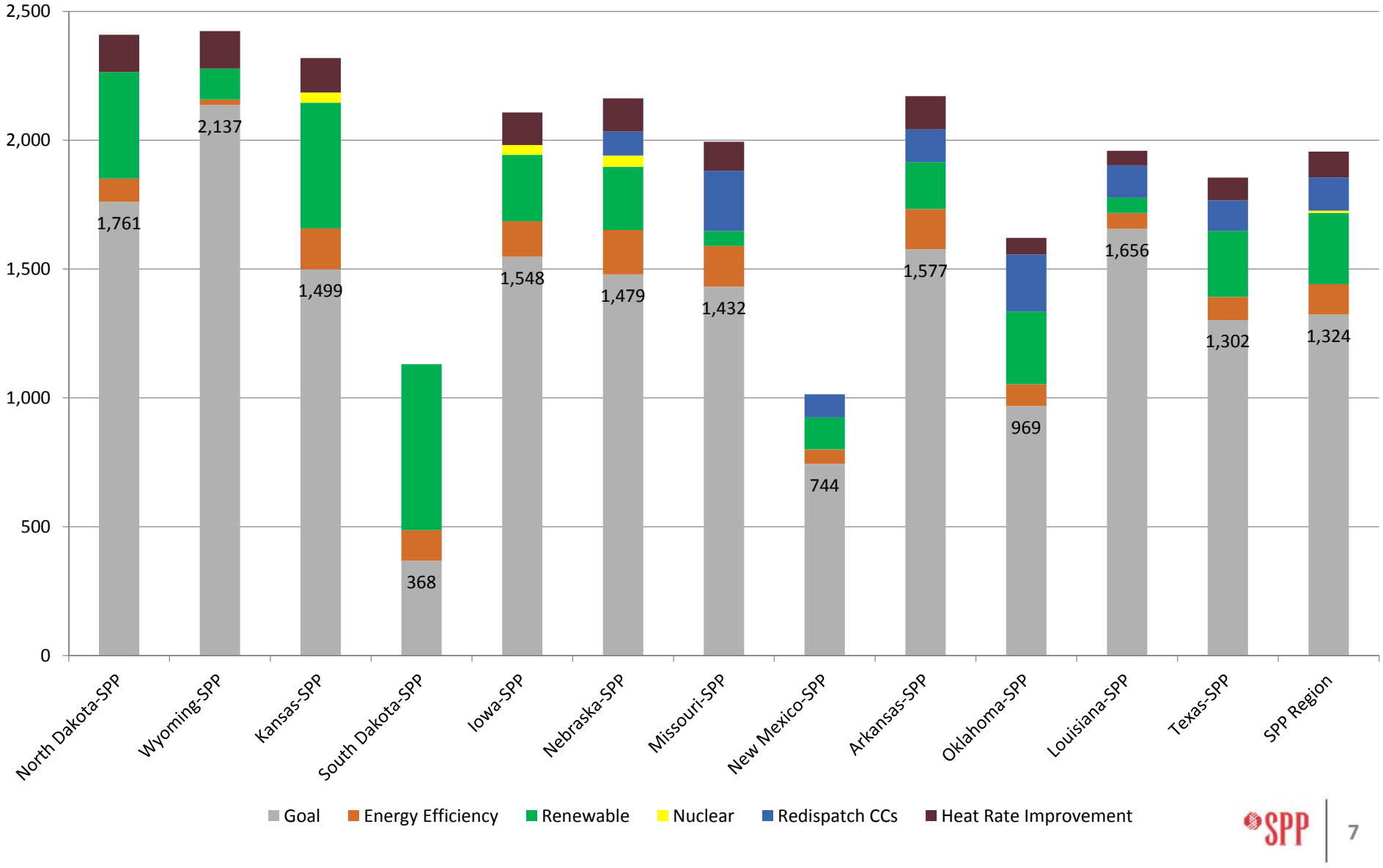
SPP Emission Goal Estimate

1. Improve efficiency of existing coal plants
   - Adjust coal CO_2 emission rate by 6%
2. Increase reliance on CC gas units
   - Adjust historical output of Coal, Oil and Gas steam based on increasing historical CC output to 70%
   - Weighted average adjustment of Coal, O/G
3. Expand use of renewable resources and sustain nuclear power production
   - Potential RE expansion (22%)
   - Adjusted EPA projection by % of SPP installed capacity by state
4. Expand use of demand-side energy efficiency
   - Projected % of avoided MWh sales
   - Adjusted EPA projection by % of SPP installed capacity by state

EPA Emission Goal Estimate (SPP States)



SPP Emission Goal Estimate



Emission Goal Estimates

State	EPA 2030 Target Rate (lbs/MWh)	SPP 2030 Target Rate (lbs/MWh)
Arkansas	910	1,577
Iowa	1,301	1,548
Kansas	1,499	1,499
Louisiana	883	1,656
Missouri	1,544	1,432
Nebraska	1,479	1,479
New Mexico	1,048	744
North Dakota	1,783	1,761
Oklahoma	895	969
South Dakota	741	368
Texas	791	1,302
SPP	N/A	1,324

FINAL RULE

Affected EGUs to be Addressed

- The EGUs that must be addressed by your plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commenced construction on or before January 8, 2014.
- (b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section...

Affected EGUs to be Addressed

- (1) Serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater (i.e., capable of selling greater than 25 MW of electricity);
- (2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and
- (3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine

BSER Building Block Changes

- **BSER BB1 Adjustments**
  - Reviewed historical efficiency improvements by interconnection
    - 4.3% East
    - 2.3% ERCOT
    - 2.1% West
- **BSER BB2 Adjustments**
  - Reviewed historical on peak CC operation
    - Redispatch to 75% capacity factor (of "net summer capability" rather than nameplate)
- **BSER BB3 Adjustments**
  - Renewable energy potential 28% of resource mix, up from 22%
- **BSER BB4 removed**

Goal Computation Overview

- Step 1
  - Compile 2012 unit-level data, aggregate to state-level, make baseline adjustments, and sum to regional baseline totals
- Step 2
  - Aggregate the adjusted historical emissions and generation to a regional level for coal steam, OG steam, and NGCC technology categories.
- Step 3
  - Identify category-specific baseline emission rates for fossil steam and NGCC

Goal Computation Overview

- Step 4
  - Calculate regional fossil steam emission rate resulting from building block 1 heat rate improvement (HRI)
- Step 5
  - Calculate regional fossil steam and NGCC generation levels resulting from building block 3 (incremental RE generation)
- Step 6
  - Calculate regional fossil steam and NGCC generation resulting from building block 2 (incremental NGCC generation)

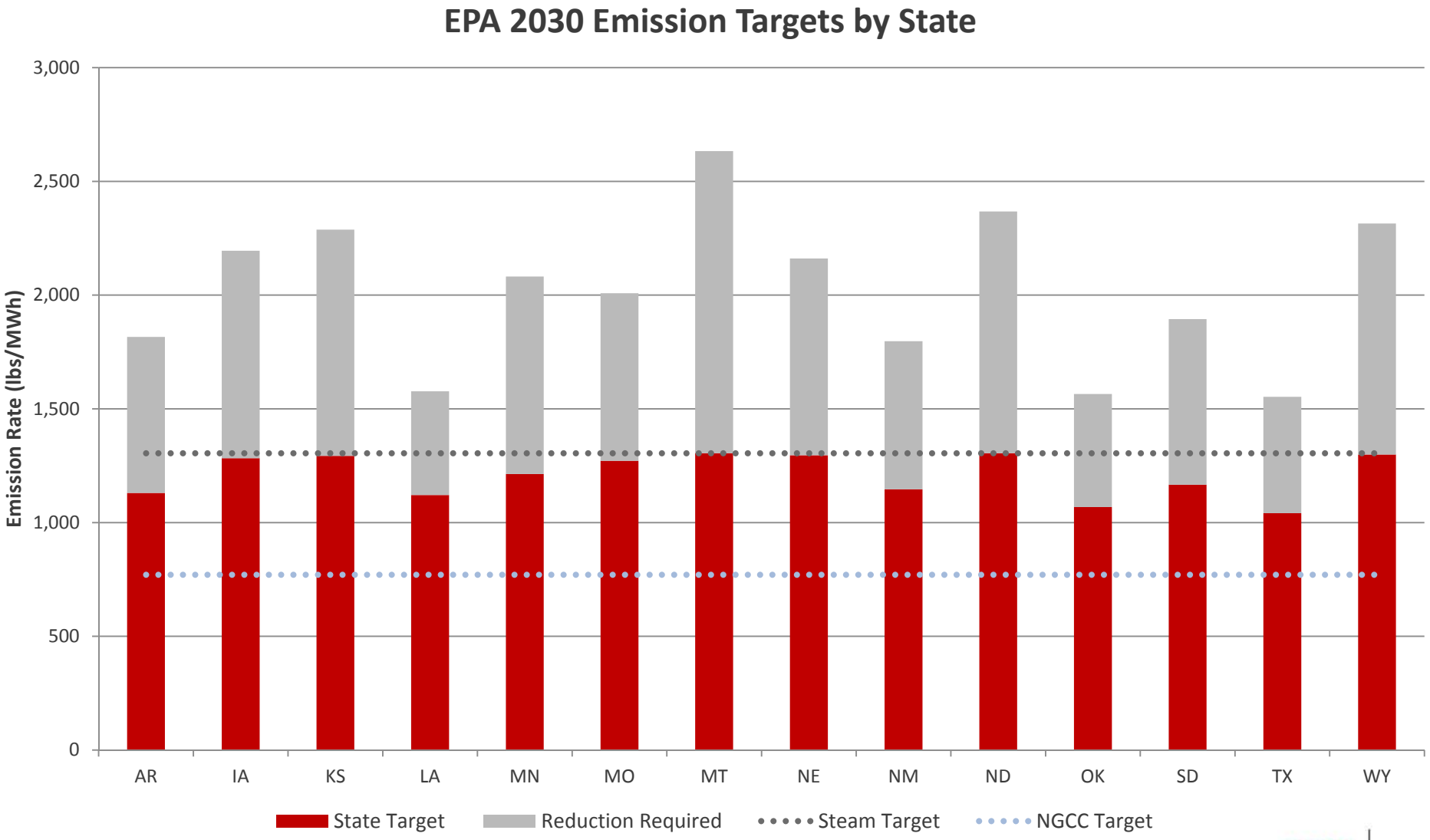
Goal Computation Overview

- Step 7
  - Determine the adjusted category-specific performance rates for each region reflecting the heat rate improvement and generation shifts
- Step 8
  - Identify the least stringent regional rate as the emission performance rate for the technology source category
- Step 9
  - Calculate weighted average of the source category rates based on each state's baseline generation mix

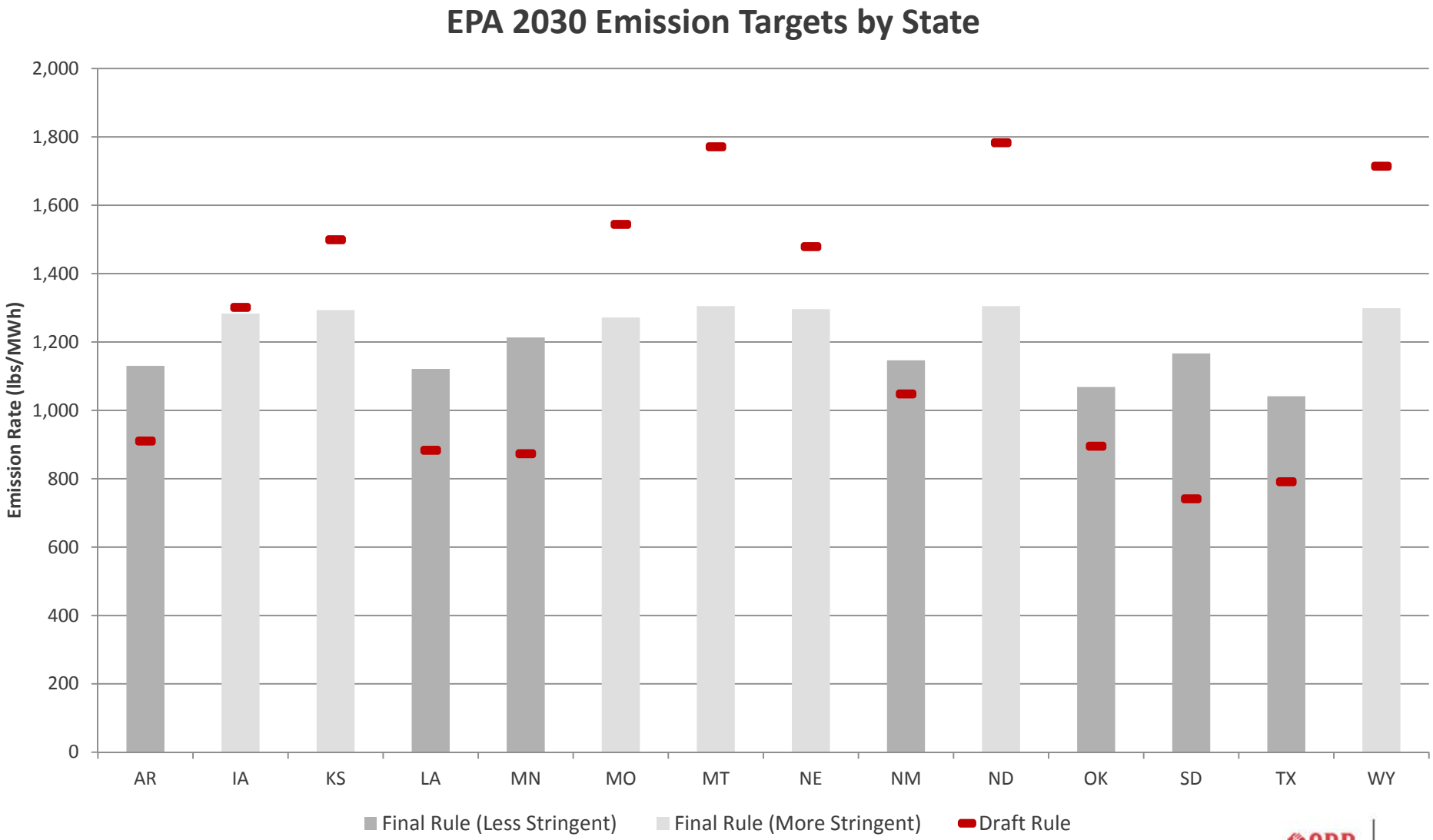
National Emission Goals by Generation Category

Affected EGU	Interim Rate (lbs/MWh)	Final Rate (lbs/MWh)
Steam generating unit or integrated gasification combined cycle (Coal/OG)	1,534	1,305
Stationary Combustion turbine (NGCC)	832	771

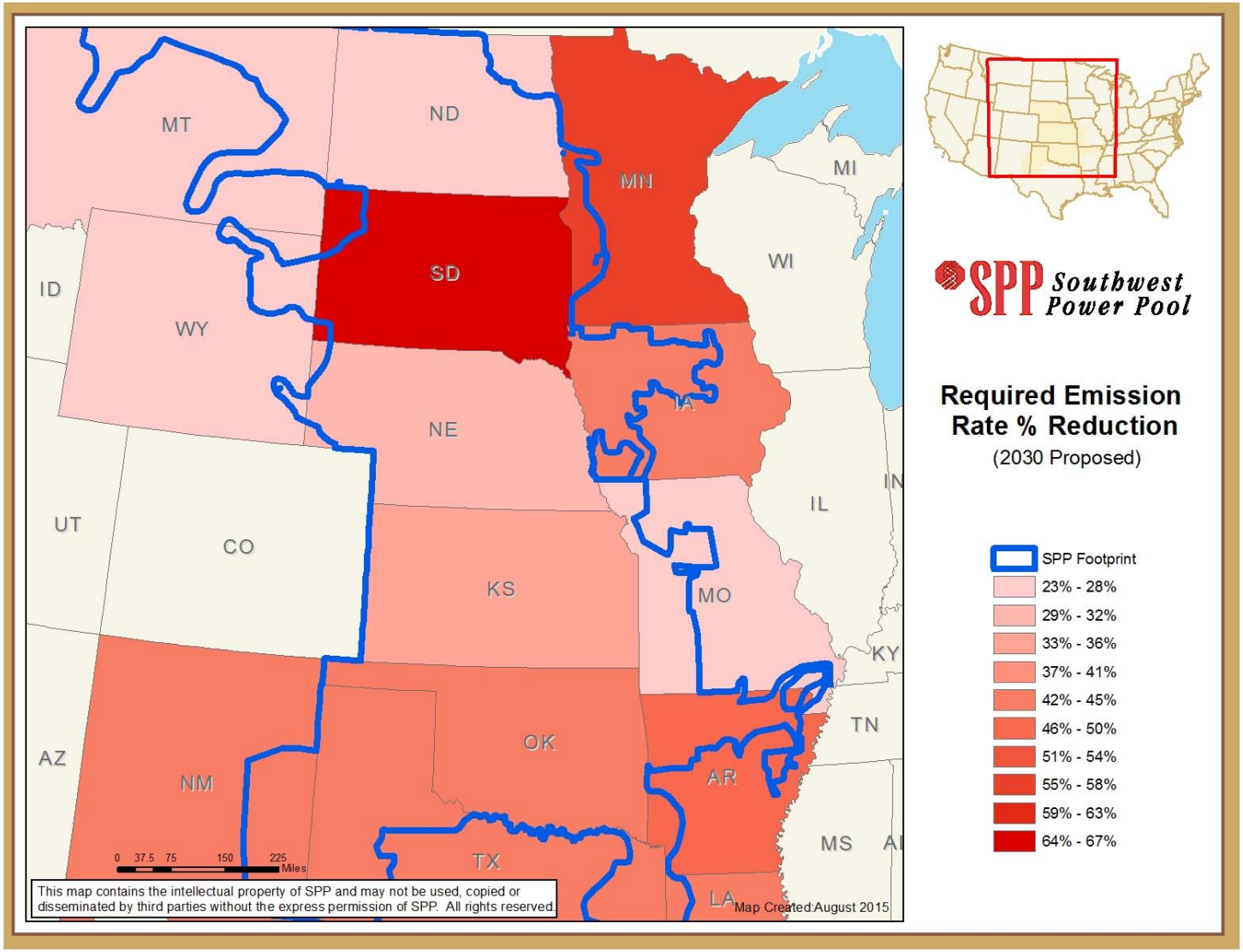
EPA 2030 Emission Targets – Final Rule



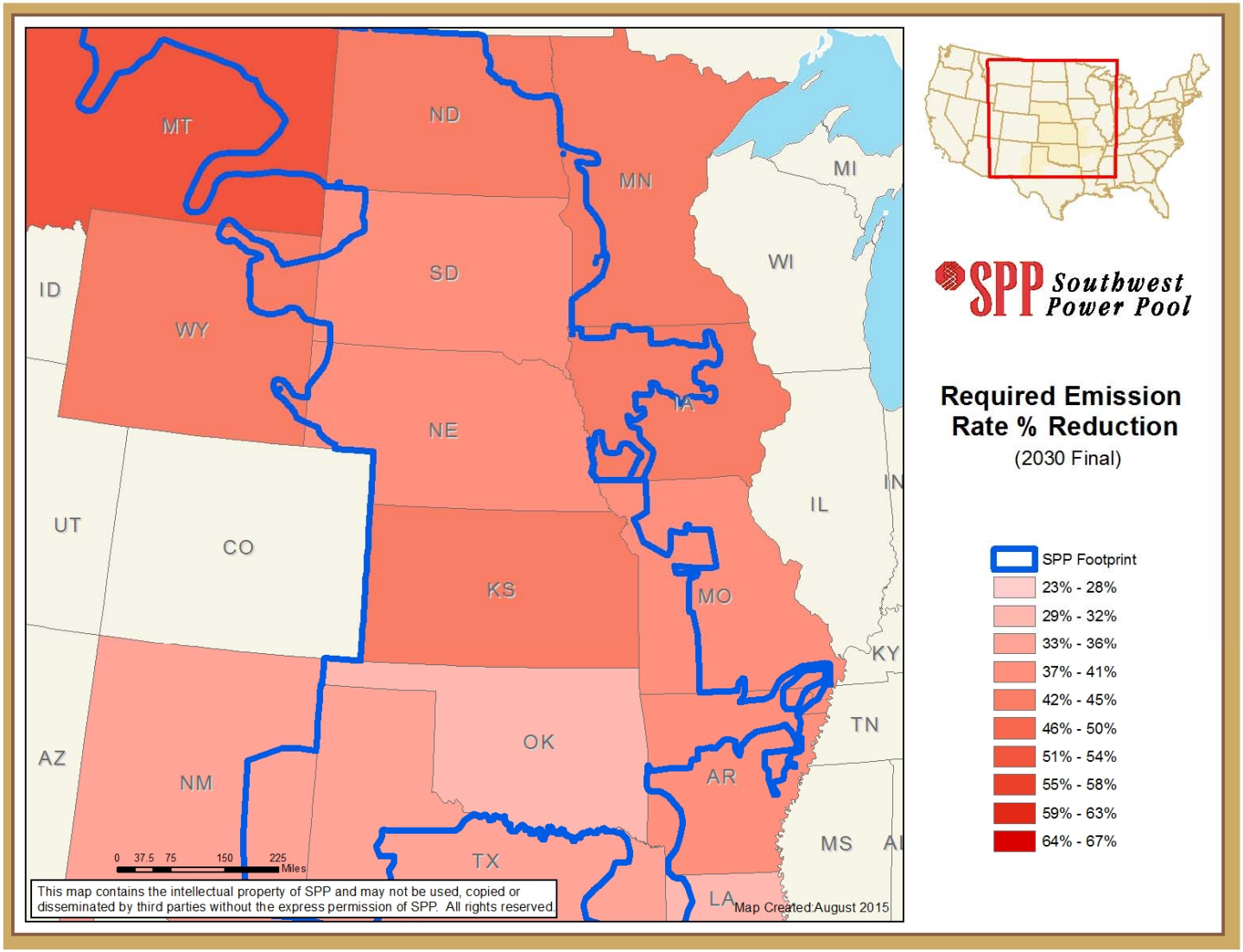
EPA 2030 Emission Targets – Rule Comparison



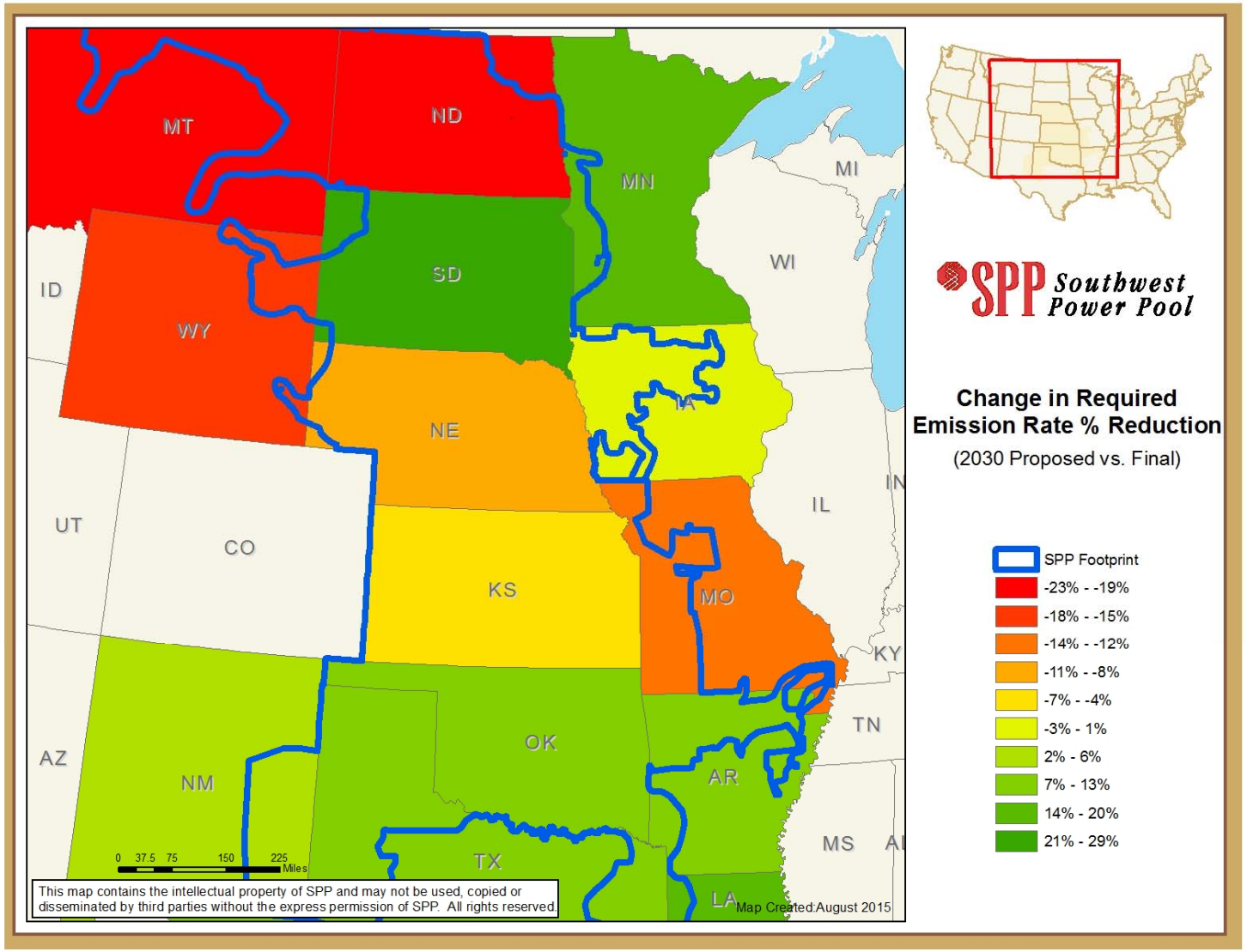
State Emission Rate Changes



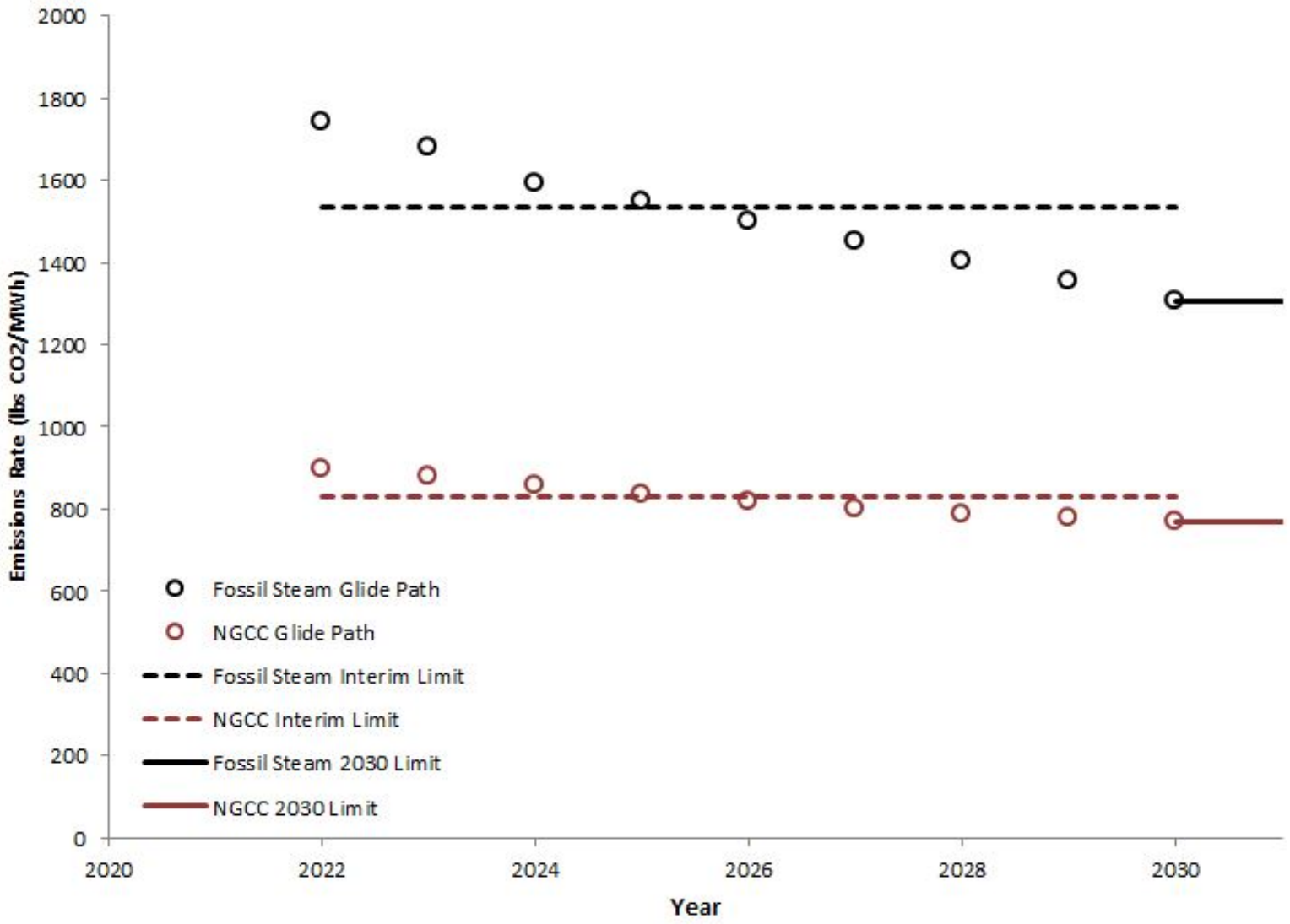
State Emission Rate Changes



State Emission Rate Changes



Affected EGU Glide Path



CO_2 Emission Goals

- New rate-based targets
  - Applied directly to EGUs by source category or,
  - State level weighted average of the source category rates based on each state's baseline generation mix
- EPA calculated mass-based targets
  - State level
  - Includes only existing EGUs or projected new generation

Clean Energy Incentive Program (CEIP)

- **Incentivize investment in certain Renewable Energy (RE) and demand-side Energy Efficiency (EE) projects**
  - Credit given to MWh generated (RE) and reduction of end-use energy demand (EE) during 2020 and or 2021
  - EPA will provide matching allowances or Emission Rate Credits (ERCs) to states that participate in the CEIP, up to an amount equal to the equivalent of 300 million short tons of CO_2 emissions
  - Wind or solar projects will receive 1 credit for 1 MWh of generation
  - Demand-side EE projects implemented in low-income communities will receive 2 credits for 1 MWh of avoided generation
- **Additional flexibility to facilitate achievement of CO_2 emission reductions required by final rule**

Clean Energy Incentive Program (CEIP)

- Additional flexibility to facilitate achievement of CO_2 emission reductions required by final rule
  - States that choose mass-based compliance may draw CO_2 emission allowances from their 2022-2029 mass-based goal and award them to eligible projects that achieve reductions in 2020 and/or 2021
  - States that choose rate-based compliance may "borrow" from the pool of ERCs they will issue during the 2022-2029 performance period and award them to eligible projects that achieve reductions in 2020 and/or 2021

IMPLEMENTATION OPTIONS

State Options

- Rate- vs Mass-based goals
- Emission Standards or “state measures”
  - Source specific standards vs. state weighted average
- Only existing EGUs vs. include new
- Emissions trading proposal
  - Cap & Trade vs. CO_2 tax

Two-Rate Approach

- *The "two-rate" approach.* First, states can choose to write plans that adopt the two national emission performance rates as *enforceable limits* on their coal and gas plants.
- Under this approach, each plant needs to meet the applicable enforceable emissions rate limit through a combination of reducing its own emissions rate and investing in emission reducing actions at other locations in the power system, either in the same state or elsewhere in the country.

One-Rate Approach

- As a second option, the Clean Power Plan establishes state-specific emission rate limits. These state-specific limits are a blend of the national emission rate limits for coal and gas plants, weighted to reflect the mix of electricity generated from the two types of plants in each state at the starting point in 2012.
- As in the two-rate approach, each power plant uses a combination of its own actions and emission rate credits to meet the applicable state-specific emission rate limit.

Mass Based Differences

- Under a mass-based approach, the state issues *emission allowances* equal to the number of tons of emissions allowed in the state. Each coal or gas plant needs one emission allowance for each ton of CO_2 that it emits. The cost of allowances then figures into decisions about which plants to operate and encourages a shift to lower- or zero-emitting power. States can decide whether to auction the allowances (using the proceeds for renewables and efficiency programs or customer rebates) or to distribute them by other means.

Federal Implementation Plan Options

- Draft federal plan out for comment
  - Rate-based federal plan for each state
  - Mass-based federal plan for each state
  - Rate-based model trading rule for potential use by any state
  - Mass-based model trading rule for potential use by any state
- Options for consideration or will the state be able to choose an option?

2017 ITP10 Futures Assumptions

SPP Staff

August 19-20th, 2015

2017 ITP10 Futures

CONVENTIONAL RESOURCE PLAN

Futures Drivers

Driver	Future 1	Future 2	Future 3
111D	Regional 111D	State 111D	No 111D
Competitive Wind	Yes	Yes	Yes
NG Supply - High Supply Due to Fracking	Yes	Yes	Yes
Severe Weather	Sensitivity	Sensitivity	Sensitivity
Long-Term Drought			
Winter impacts			
Load Growth	Normal	Normal	Normal
Cost of Capital Changes (Significant Increase)	Sensitivity	Sensitivity	Sensitivity
Limited ability to build			
8-12% interest payments			
Solar Development (Substantial)	Large Scale	Large Scale	Large Scale/Roof Top
Impact on Generation Due to Constraints	Modeling Issue	Modeling Issue	Modeling Issue

2017 ITP10 Solar Recommendation

- **2015 SWEPCO and TVA Integrated Resource Plans**
  - **Utility scale solar as percentage of peak demand**

IRP	2020	2025	2035
SWEPCO	1%	7%	16%
TVA	<1%	3%-5%	10%-12%

  - **Roof top solar as percentage of peak demand**

IRP	2020	2025	2035
SWEPCO	<1%	<1%	1%
TVA	<1%-2%	1%-4%	2%-7%

2017 ITP10 Solar Recommendation

- Utility-scale solar
  - F3 assume 1% peak demand in 2020, 6% in 2025, and 10% in 2035
  - F1 and F2 use output of carbon restricted strategist runs if not assume 6% in 2020/2024 and 10% in 2025/2027
  - Assign by demand group using utility scale solar prototype 10 MW capacity increments
  - Use 30% utility scale solar prototype capacity factor and centrally located hourly profile for each sub-region

2017 ITP10 Solar Recommendation (Approved)

- F3 Utility scale solar

Sub-Region	2020 Utility scale solar 1%	2025 Utility scale solar 3%	2035 Utility scale solar 6%
SPP-IS	40	170	340
SPP-Nebraska	70	225	450
SPP-KSMO	150	500	1000
SPP-South	300	940	1880
SPP Total	**560**	**1835**	**3670**

- F1 and F2 Utility scale solar

Sub-Region	2020 Utility scale solar 3%	2025 Utility scale solar 5%
SPP-IS	160	280
SPP-Nebraska	215	380
SPP-KSMO	490	820
SPP-South	895	1575
SPP Total	**1760**	**3055**

Excludes WAPA - Upper Great Plains East
Additional to existing and renewable resource plan solar 340 MW

2017 ITP10 Solar Recommendation

- Roof top – Residential, Commercial, and Industrial
  - F3 assume 1% peak demand in 2020, 2% in 2025, and 4% in 2035
  - Assign by demand group using roof top commercial and industrial solar prototype 1 MW capacity increments
  - Site at load buses on a pro rata basis either lesser of top 30 buses or greater than 90th percentile by demand group
  - Use 23% rooftop solar prototype capacity factor and centrally located hourly profile for each sub-region

2017 ITP10 Solar Recommendation (Approved)

- **F3 Roof top solar**

Sub-Region	2020 Roof top Solar 0.5%	2025 Roof top Solar 1%	2035 Roof top Solar 2%
SPP-IS	26.5	57.5	137
SPP-Nebraska	35	75	164.5
SPP-KSMO	80.5	166.5	356
SPP-South	148	315.5	716.5
SPP Total	**290**	**614.5**	**1374**

Excludes WAPA - Upper Great Plains East
Additional to current DG projections assumed in load forecasts

- **F3 Utility Scale Solar**

Sub-Region	2020 Utility scale solar 1%	2025 Utility scale solar 3%	2035 Utility scale solar 6%
SPP-IS	40	170	340
SPP-Nebraska	70	225	450
SPP-KSMO	150	500	1000
SPP-South	300	940	1880
SPP Total	**560**	**1835**	**3670**

2017 ITP10 Futures

MINIMUM CAPACITY & RETIREMENTS

Coal Retirements

- How would a 25% minimum capacity on SPP owned coal units effect coal retirements in SPP's CPP State-by-State analysis?
- Compared CPP State analysis coal retirements to a CPP State analysis with 25% min cap
- Utilized CPP State by State analysis PROMOD runs
  1. CPP State reference case + $45/ton CO2 tax
     - State Effluent Structure
     - Copper Sheet
     - No interchange with adjacent pools
  2. Previous run + 25% Coal unit minimum capacity

Coal Retirements Comparison

- **Less retirements are needed with the implementation of a 25% minimum capacity on coal units with SPP ownership**

Pool	CPP State Retirements (MW)	25% Min Cap Retirements (MW)	Delta (MW)	Consistent with State CPP?
SPP	4,599	4,025	574	No

2017 ITP10 Futures

CONVENTIONAL CYCLING

Cycling

- Definition: The combination of a shut-down and start-up is known as a ‘cycle’

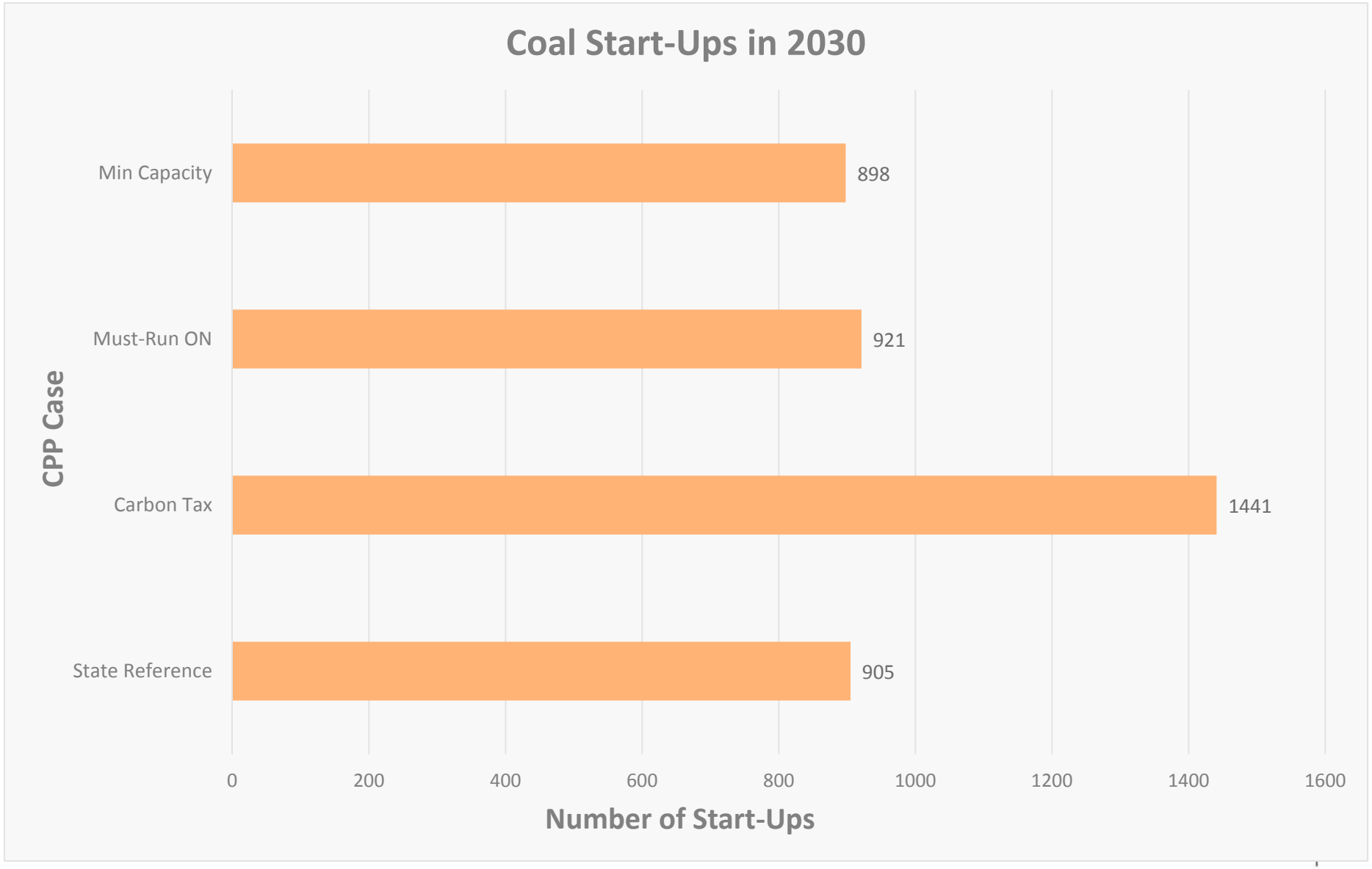
- Cycling can be evaluated in PROMOD by the number of unit start-ups in a given case.

- Utilized CPP State by State analysis PROMOD runs to compare the number of start-ups in the CPP State analysis to CPP State analysis with carbon tax adder, must-run flag, and 25% min cap.

Assumptions

- CPP State reference case
  - State Effluent Structure
  - Copper Sheet
  - No interchange with adjacent pools
- CPP State reference case + $45/ton CO2 tax
- CPP State reference case + 25% Coal unit minimum capacity
- CPP State reference case + Coal Unit Must-Run Status Flag ON

Results


Coal Start-Ups in 2030
Min Capacity
898
Must-Run ON
921
Carbon Tax
1441
State Reference
905
CPP Case
0
200
400
600
800
1000
1200
1400
1600
Number of Start-Ups

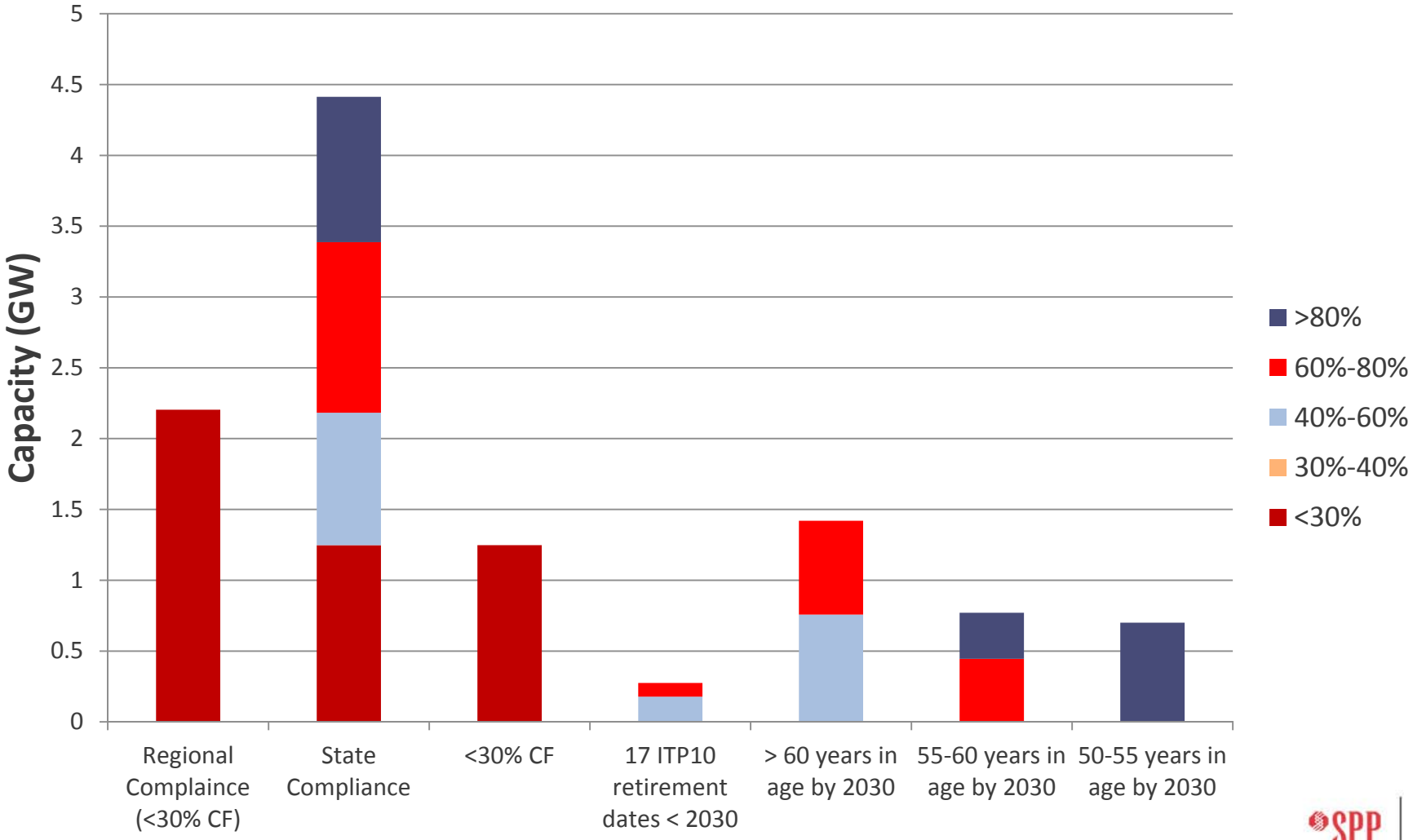
2017 ITP10 Futures

CPP IMPLEMENTATION

Incremental Coal Retirements Details from CPP State by State compliance analysis

- After coal retirements with < 30% CF ~1200 MW only targeting states not meeting goal
- Additional coal retirements assumed using tiered approach only targeting states not meeting goal
  - Tier 1: 2017 ITP10 retirement dates < 2030 ~300 MW
  - Tier 2: > 60 years in age by 2030 ~1400 MW
  - Tier 3: 55-60 years in age by 2030 ~800 MW
  - Tier 4: 50-55 years in age by 2030 ~700 MW
  - State Compliance Total ~4400 MW

Capacity by Capacity Factor @ $45/Ton Carbon Cost Adder of Assumed Coal Retirements



Unit Retirement Recommendation

- Leverage CPP results
  - Provides a ranking of SPP coal and gas steam units under a copper sheet, limited interchange, and $45 carbon adder
  - Rank Non-SPP coal and gas units
  - Coal steam use age and capacity factor
  - Gas steam use age and average cost/MWH
- Utility review for exceptions that might include units with completed retrofits, small generation portfolios, and repowering with natural gas
- Use to recommend coal and gas steam unit retirement levels where gen review retirements show retirement dates outside of study scope

Unit Retirement Recommendation

- Example tiered approach for coal steam (Age by 22/24 and by 25/27)
  - < 30% Capacity Factor and > 60 years in age then > 50 years then > 40 years
  - 40%-60% Capacity Factor and > 60 years in age then > 50 years then > 40 years
  - 60%-80% Capacity Factor and > 60 years in age then > 50 years then > 40 years
- Assumes newer coal units are more flexible to cycle
- Retirements for gas steam (by 22/24 by 25/27)
  - Retire gas steam units not running in CPP and > 60 years in age then > 50 years
  - Retire a % of High average cost/MWh and > 60 years in age then > 50 years
  - Retire a % of Medium average cost/MWh and > 60 years in age then > 50 years then > 40 years
- Send out data request for utilities review reasonableness and provide exceptions that might include units with completed retrofits, small generation portfolios, and repowering with natural gas

Unit Retirement Motion

- Accept staff's method to produce a list of potential retirements that will be reviewed for rejection by members and will include the assumed carbon price to produce that list.

Energy Efficiency Recommendation

- **Develop draft data request to determine existing and new energy efficiency in member submitted load forecasts with the purpose of meeting emissions targets and proposing additional levels of energy efficiency**
- **Question: What is the EPA definition of existing versus new energy efficiency? What is the bright line date?**
- **Blanket peak and/or energy reduction in CPP Futures**
  - **Utilize varying levels projected by EPA**
    - **For example, use up to 20% of EPA intensity for F1 and use up to 30% of EPA intensity for F2 including member submitted assumptions**
  - **Allow for exceptions?**

2017 ITP10 Futures

OTHER ASSUMPTIONS

EPA Goal Implementation

Staff Recommends

- 2020 Model
  - Implementation of the 2022-2024 EPA goals
    - EPA interim goals begin in 2022
    - 2020 model is needed for RCAR II
    - Improves staging
- 2025 Model
  - Implementation of the 2025-2027 EPA goals

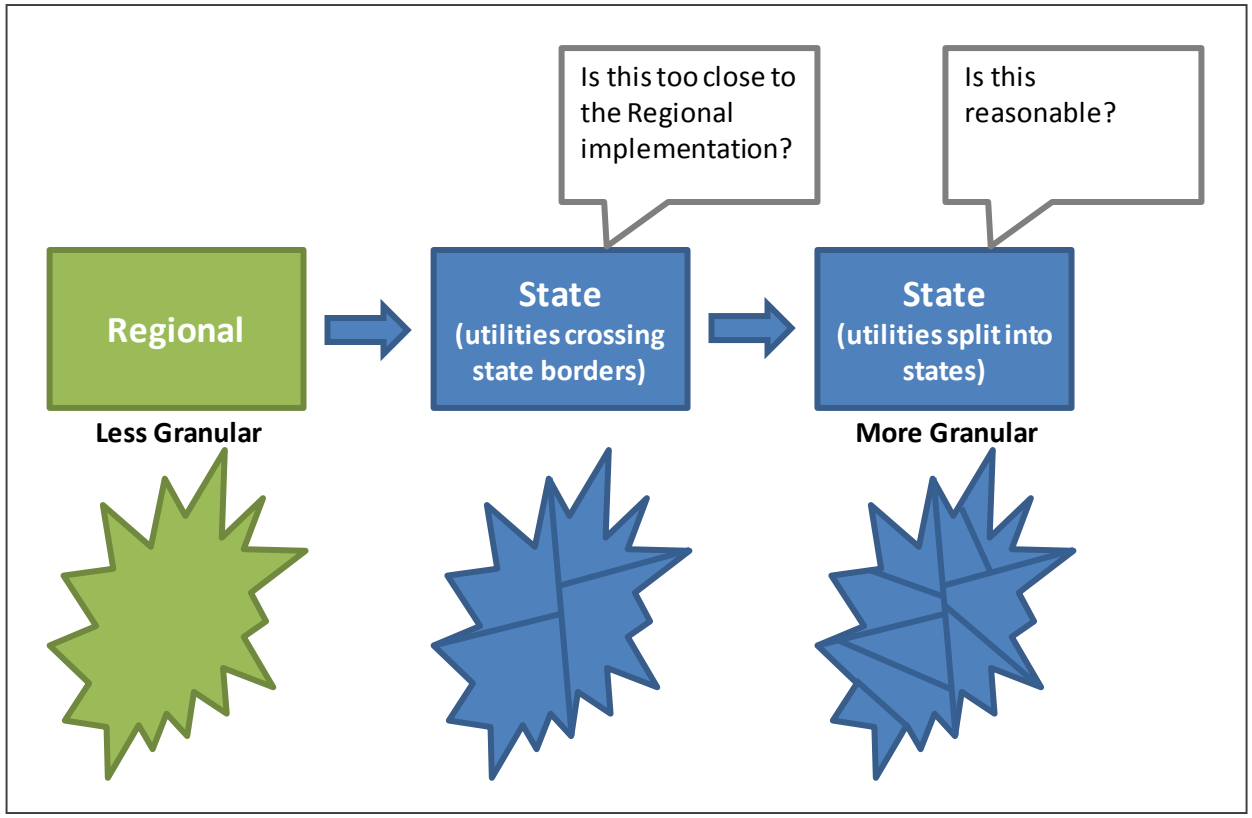
CPP Compliance Considerations

	Future 1 (Regional CPP) **Global**	Future 2 (State CPP) **Local**
Energy Efficiency	Less	More
Renewables	More Wind & site more globally	Less Wind & site more locally
	Site Solar globally	Site Solar locally
Conventionals	Less Retirements	More Retirements
	Higher Emissions Mass Target Higher Emission Rate Target	Lower Emissions Mass Target Lower Emission Rate Target
	$30 CO2 Tax for Dispatch	$45 CO2 Tax for Dispatch

- **What is coal to gas conversion philosophy?**

CPP Compliance Considerations

- On what level do we implement state compliance?



Annual GHI Map & Sample Sub-Regions for Siting

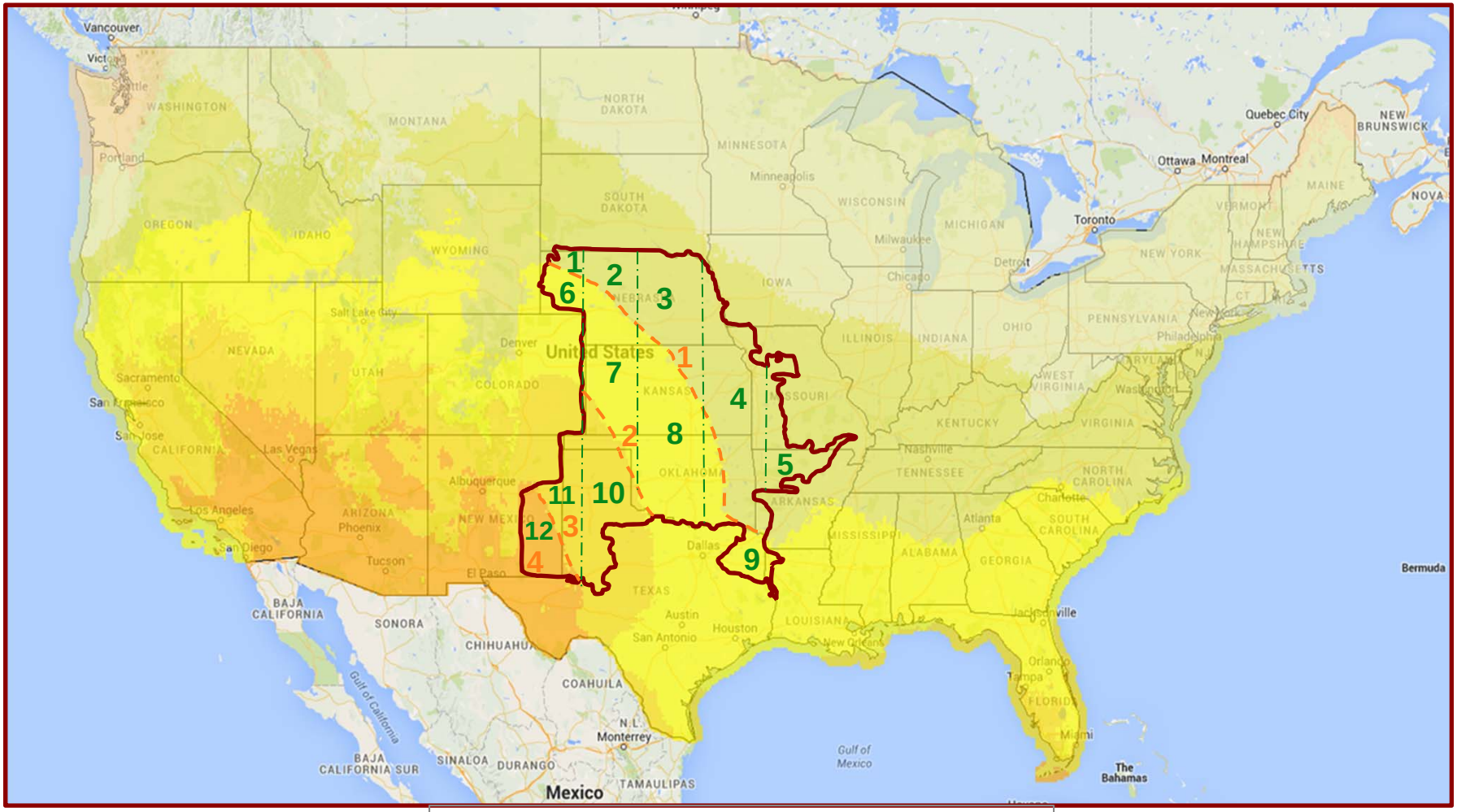


Figure 4.1 | *"NREL Solar Prospector: GHI"*

2017 ITP10 Futures

APPENDIX

Potential Scenario Analysis – Key Drivers

Scenario 1

Input	Low Range	Mid Range	High Range
Renewables	X		
Energy Efficiency		X	
Retirements			X
Dispatch (CO2 Cost)	Slider	Slider	Slider

Scenario 2

Input	Low Range	Mid Range	High Range
Renewables			X
Energy Efficiency	X		
Retirements	X		
Dispatch (CO2 Cost)	Slider	Slider	Slider

Potential Scenario Analysis – Key Drivers

Scenario 3

Input	Low Range	Mid Range	High Range
Renewables	X		
Energy Efficiency		X	
Retirements		X	
Dispatch (CO2 Cost)	Slider	Slider	Slider

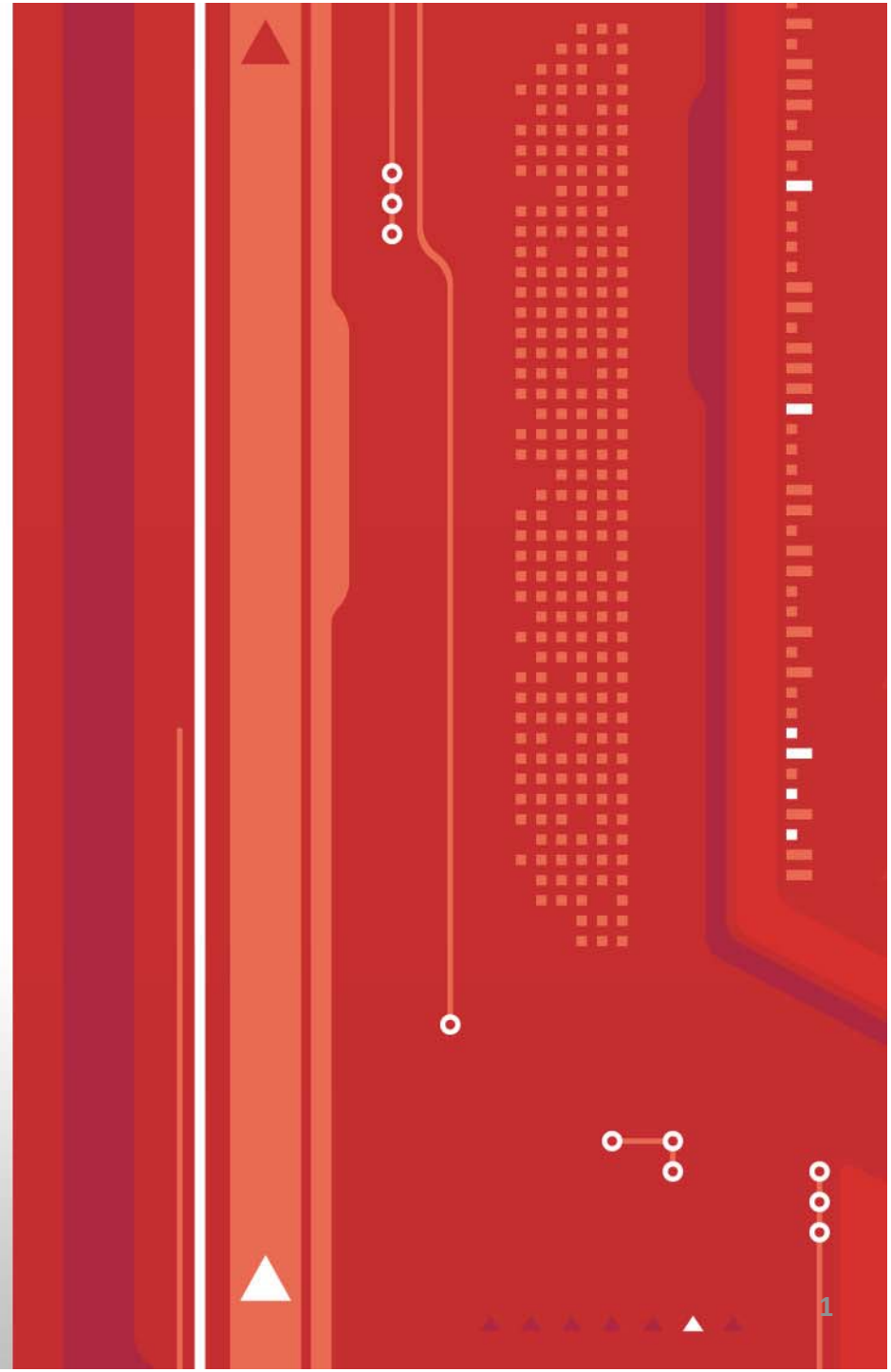
Scenario 4

Input	Low Range	Mid Range	High Range
Renewables		X	
Energy Efficiency		X	
Retirements		X	
Dispatch (CO2 Cost)	Slider	Slider	Slider

2017 ITP10 Portfolio Consolidation

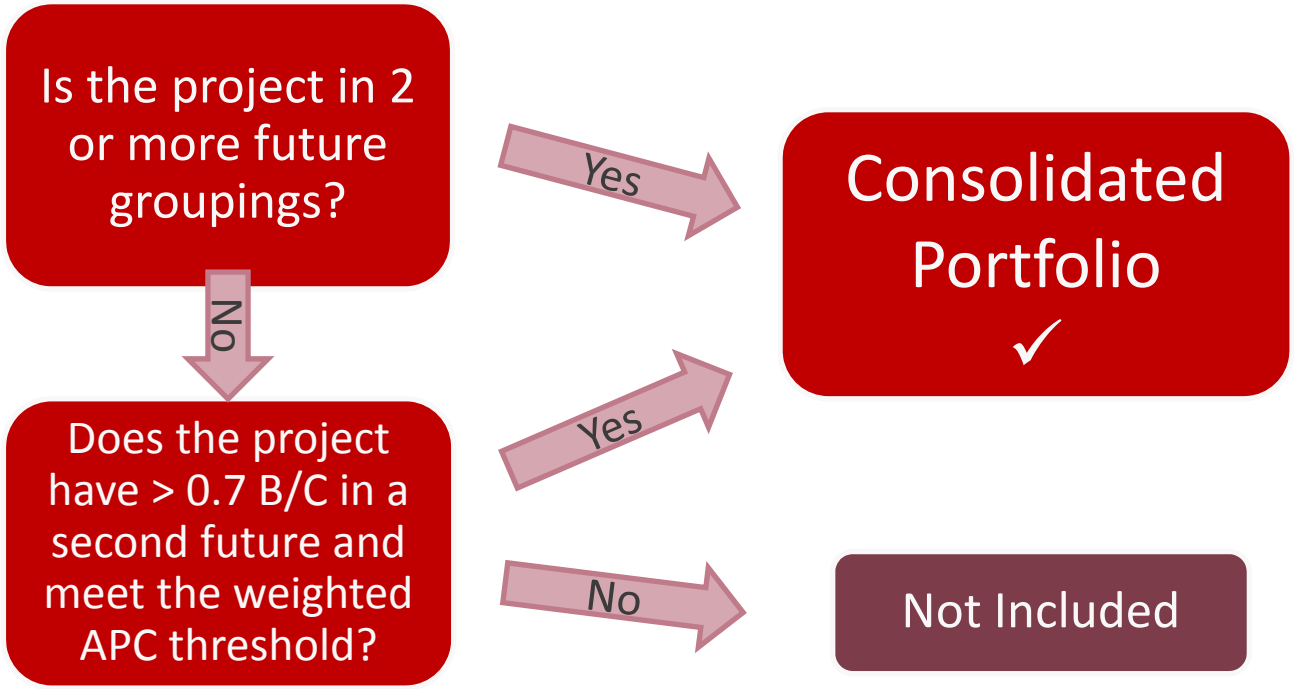
SPP Staff

August 19th, 2015



Consolidation Recommendation

- **Criteria 1: Projects in at least 2 of 3 future portfolios are included in the consolidated portfolio**
- **Criteria 2: Projects in only 1 future portfolio must have a Weighted sum APC B/C ratio above 0.9 and a 1-year B/C greater than 0.7 in a second future**



Consolidation

		1-year B/C Ratio Included in Future portfolio?			Consolidated Portfolio
Project ID	**1-Year Cost**	**Future 1**	**Future 2**	**Future 3**	
Project 1	$ 39,152,000	1.12	2.83	0.98	
		Yes	Yes	Yes	**Yes**
Project 2	$ 12,745,000	0.70	2.83	0.25	
		No	Yes	No	**No ***
Project 3	$ 989,000	3.60	1.20	0.30	
		Yes	Yes	No	**Yes**
Project 4	$ 800,000	0.25	1.60	0.75	
		No	Yes	No	**No ***
Project 5	$ 1,700,000	1.50	0.40	0.70	
		Yes	No	No	**No ***

*Project will move on for further assessment, per criteria 2

Weighted APC Threshold Options

Example 1

- **Each Future is weighted equally at 1/3**

Example 2

- **50% weighting for Future 2 (state by state implementation), 25% for Futures 1 and 3**

Weighted APC Performance Example

		1-Year Benefit B/C Ratio			Example 1*	Example 2*
Project ID	**1-Year Cost**	**Future 1**	**Future 2**	**Future 3**	**Weighted B/C ratio**	
Project 2	$ 12,745,000	$ 8,921,500	$ 25,247,845	$ 6,311,961		
		0.70	**2.83**	0.25	**1.26**	**1.65**
Project 4	$ 800,000	$ 200,000	$ 1,280,000	$ 600,000		
		0.25	**1.60**	0.75	**0.87**	**1.05**
Project 5	$ 1,700,000	$ 2,550,000	$ 680,000	$ 1,190,000		
		1.50	0.40	0.70	**0.87**	**0.75**

*Example 1 reflects all Futures weighted equally, Example 2 reflects Future 2 weighted 50%

APPENDIX

Additional Weighted APC Performance Example

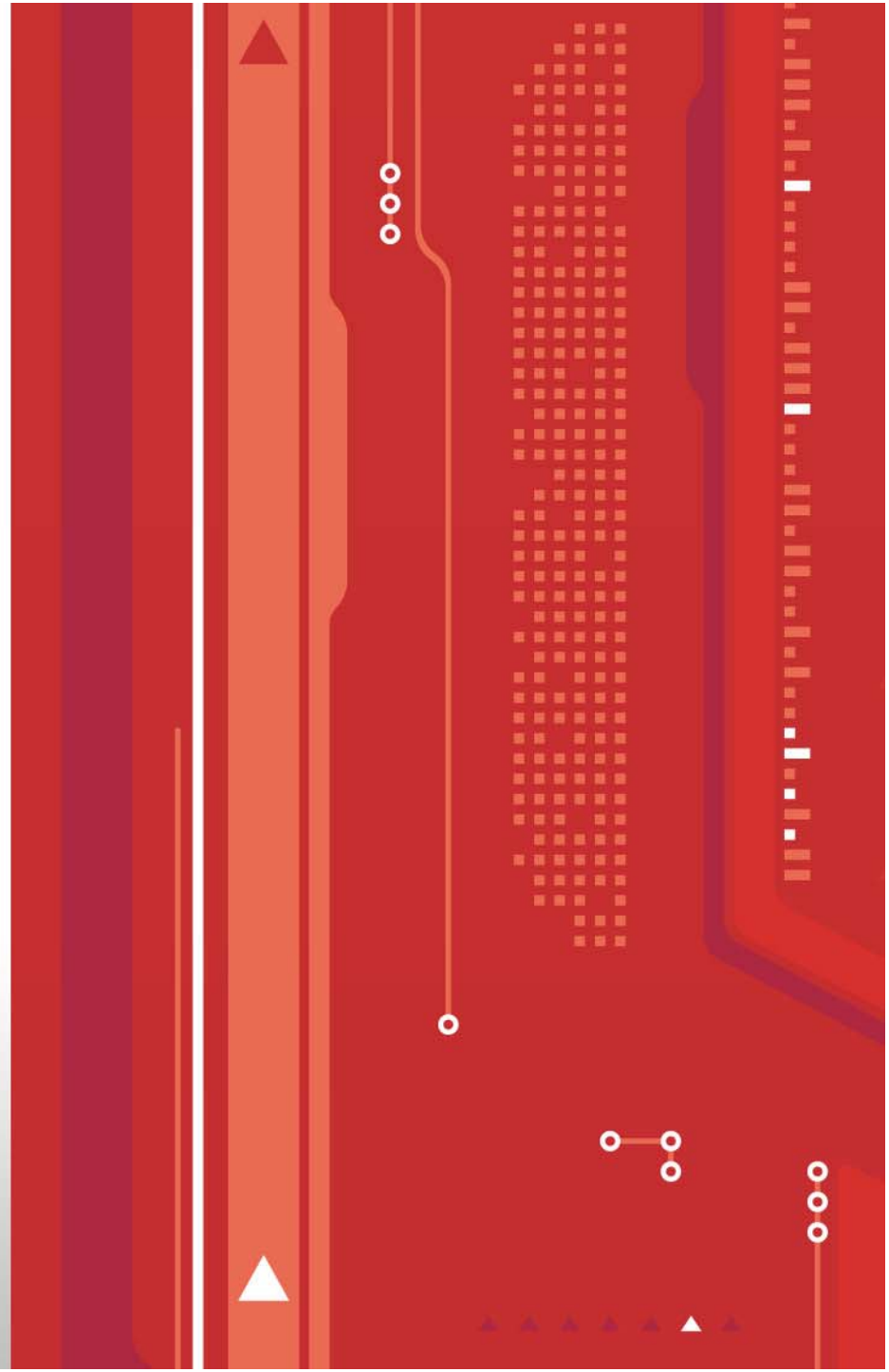
		1-Year Benefit B/C Ratio			Example 1*	Example 2*
Project ID	**1-Year Cost**	**Future 1**	**Future 2**	**Future 3**	**Weighted B/C ratio**	
Project 1	$ 1,943,000	$ 445,249	$ (756,522)	$ 2,226,243		
		0.23	-0.39	**1.15**	**0.33**	**0.15**
Project 2	$ 1,454,000	$ (8,947)	$ 4,111,481	$ (15,560)		
		-0.01	**2.83**	-0.01	**0.94**	**1.41**
Project 3	$ 979,088	$ 12,378,000	$ (160,000)	$ 442,000		
		12.64	-0.16	0.45	**4.31**	**3.19**
Project 4	$ 800,000	$ (80,000)	$ (400,000)	$ 9,000,000		
		-0.10	-0.50	**11.25**	**3.55**	**2.54**
Project 5	$ 1,385,174	$ 1,200,000	$ 1,289,000	$ 1,210,000		
		0.87	**0.93**	0.87	**0.89**	**0.90**
Project 6	$ 478,000	$ 328,944	$ 648,248	$ 119,500		
		0.69	**1.36**	0.25	**0.76**	**0.91**
Project 7	$ 1,632,500	$ 4,066,002	$ 643,784	$ 409,989		
		2.49	0.39	0.25	**1.05**	**0.88**
Project 8	$ 140,000	$ 314,905	$ (29,236)	$ 88,978		
		2.25	-0.21	0.64	**0.89**	**0.62**

*Example 1 reflects all Futures weighted equally, Example 2 reflects Future 2 weighted 50%

2017 ITP10
Resource Additions

August 19th, 2015

ESWG



SPP Southwest Power Pool

Data Request

Sent the following questions to all GOs and TOs for all On Schedule GIAs:

- Has the generating resource acquired the funding for generating equipment in an amount constituting a majority of the queue position (MW)?
- Has construction of the generating resource with major equipment procurement contracts awarded commenced?
- Has the generating resource participated in an RFP that will result in a publicly availably PPA?
- For the respective generating resource, has the Interconnection Customer responded to a publicly announced RFP?
- Has the TO procured major equipment for the Transmission Owner's Interconnection Facilities (TOIF) and Network Upgrades (NU)?
- Has the TO started construction of the TOIFs and NUs?

Results

- Review of data request responses
  - "Yes" responses to two focused questions resulted in units included in Generation Review
  - Add 100 MW to Arbuckle Mountain Wind
  - Add 100 MW to Buckeye Wind
- Review of NDRs approved through Generation Review
  - Remove 790 MW based on Appendix B and other public information
- NDR amounts from 1,633 MW to 1,043 MW

Preliminary Siting

- Identified gaps during this process:
  - RP1 shows shortfall for WFEC:
    - 100 MW addition to Balko Wind
    - 36 MW addition to Roosevelt Wind

Staff Recommendation

SPP recommends the ESWG approve the inclusion of the Non-Designated Resources into 2017 ITP10 as posted.

APPENDIX

ITP10/20 Resource Inclusion Background

6/3 ESWG Approval:

Generation interconnection resources and facilities are included in the ITP models if they have an executed Interconnection Agreement (IA) that is not on suspension and minimal network upgrade costs. Generation capacity will automatically be designated to any utility once there is an executed transmission service agreement.

Proposed resources and facilities that have a high probability of going into service (i.e. If a planned generating resource does not have a TSR filed service agreement but does have a high probability of going into service) will be designated to a utility if it meets all of the following requirements:

ITP10/20 Resource Inclusion Background

- A Resource Addition Request (RAR) has been sent to SPP requesting the generation capacity be included into the ITP;
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA; and
- The generating resource will have firm contract for delivery in one or more forms:
  - The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts; or
  - The utility to be designated will own and operate the resource or has procured a Purchase Power Agreement (PPA) from the generation owner

ITP10/20 Resource Inclusion Background

- If a generating resource does not meet all the above requirements, a RAR for generation capacity to be included in a long-term ITP assessment can be made to ESWG on a case by case basis. ESWG will take into account the following, but not limited to, additional points:
  - A Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable
  - An RFP for the generating resource has been awarded, if applicable.

- All other resource expansion needs will be determined through the SPP resource planning process

	Approved		
Generator Name	Maximum Capacity (MW)	Other Entities-in SPP Ownership (%, 2025)	Other Entities-in SPP Ownership (MW, 2025)
Arbuckle Mountain Wind	100	0	0
Axtell Wind	48.3	100	48.3
Balko Wind	300	33.33	99.99
Blue Canyon Wind II	151.2	100	151.2
Blue Canyon Wind V	99	20.6	20.394
Buckeye	100.2	0	0
Buffalo Dunes	250	20	50
Chisholmview Wind	302.8	33.29	100.80212
Cimarron I	365.6	54.87	200.60472
Cimarron II	200.1	34.48	68.99448
Dempsey Ridge Wind	132	100	132
Elk City Wind II	99	100	99
Hancock County:WT1-148_OTHSPP	18.68	100	18.68
Kingfisher Wind	300	100	300
Marshall County Wind	74	66.21	48.9954
Roosevelt Wind	300	16.67	50.01
Smoky Hills WF ALL	250	14.72	36.8
Spearville	457	45.3	207.021

***Maximum Capacity changes would not affect utilities' ownership a**

Recommended		
Maximum Capacity (MW)	Other Entities-in SPP Ownership (%, 2025)	Other Entities-in SPP Ownership (MW, 2025)
200	50	100
0	0	0
200	0	0
151.2	100	151.2
99	20.6	20.394
200.2	49.95	99.9999
250	20	50
237	14.77	35.0049
165	0	0
131.1	0	0
132	100	132
99	100	99
18.68	100	18.68
300	100	300
25	0	0
250	0	0
250	14.72	36.8
250	0	0

ımounts, any capacity added or removed would be with respect t

Comments
Addition to NDRs
No Change
No Change
Addition to NDRs
No Change
No Change
No Change
No Change
No Change
No Change

to the Other Entities-in SPP PROMOD area.

RCAR II Modeling Discussion

August 20, 2015

Josh Ross

SPP Southwest Power Pool

TRAPPED GENERATION POCKETS

Trapped Generation Pockets Approaches

- Option 1a: Status Quo
  - Producing problematic zonal APC results with base case that is transmission deficient
- Option 1b: Move Wind to Zonal Load Centers
- Option 1c: Remove Wind
- Option 1d: Hybrid Approach
- Option 1e: Incremental Approach

- Today: Staff and ABB thoughts and recommendations on approaches, get input from stakeholders

Option 1b: Move Wind to Zonal Load Centers

Wind that is dependent on the HWBW transmission is moved the host zone's largest load center (~5.0 GW). Same capacity, but decreased capacity factors.

Pros:

- Addresses the Trapped Generation issue; results are more reasonable than the Status Quo
- Logic behind the approach is technically sound.
  - Wind would not be developed at these sites if not for the HWBW transmission
  - Zones would still need to meet their public policy mandates/goals, and this allows that to happen
- Generation assumptions are consistent between base and change cases (except for siting), as installed capacity is equal between the two

Cons:

- Moderate complexity in determining where to locate the wind at load centers, and vet
  - Sited such that new congestion at the load center is minimal or avoided; add close to load, and divide into smaller units if needed
- Could mask expected base case congestion due to power flowing into a load center (although we're not noticing this in test results)

Option 1c: Remove Wind

Wind that is dependent on the HWBW transmission is removed from the base case model (~5.0 GW).

Pros:

- Addresses the Trapped Generation issue; results are more reasonable than the Status Quo
- Logic behind the approach is somewhat technically sound
  - Wind would not be developed at these sites if not for the HWBW transmission
  - However, ignores that wind (or other generation) might be added elsewhere instead
- Easy to implement

Cons:

- Simply adding cheap capacity in the change case can overstate benefit
- Inconsistent generation assumptions between base and change cases can capture more than just the benefit of the new transmission

Option 1d: Hybrid Approach

Regional benefit = Regional benefit of **Status Quo**

Zonal allocation factors = Zonal allocation factors of **Remove Wind** approach

Pros:

- Addresses the Trapped Generation issue; results are more reasonable than the Status Quo
- Easy to implement

Cons:

- Zonal benefits calculation is still problematic
  - Example on next slide
- Mixing approaches/mixing results can produce unexpected and problematic final results (ABB)

Option 1d: Hybrid Approach Example

	Status Quo	Remove Wind	Hybrid*
Regional Benefit ($M)	$100	$500	$100
Zone A Benefit ($M)	$20	$100	$20
Zone B Benefit ($M)	($10)	$40	$8
Zone C Benefit ($M)	$50	$50	$10

***Hybrid $_{\text{zone X}}$ = Status Quo $_{\text{regional}}$ * (Remove Wind $_{\text{zone X}}$ / Remove Wind $_{\text{regional}}$)**

- Numbers are made up for example purposes
- Zone A – Benefit is not any more or less reasonable with hybrid approach vs. status quo
- Zone B – Representative of zone in a trapped generation pocket. Benefit is more reasonable with hybrid approach vs. status quo
- Zone C – Nowhere near any of the trapped generation or wind that is removed. **Their benefit is less reasonable with hybrid approach (should be ~$50M).**

Option 1e: Incremental Approach

Isolate the projects creating the trapped generation pocket ("wind" projects); measure the benefit of these projects separately from the rest of the projects, and add up the incremental benefits.

Pros:

- Avoids use of a true base case with the large LMP differentials, yet still designed to capture benefits of all projects

Cons:

- The LMP differentials still crop up when isolating the just "wind" projects
  - **Does not fix the problem with the Status Quo**
- Complex implementation
- Mixing approaches/mixing results can produce unexpected and problematic final results (ABB)

ABB Feedback

- Option 1b and 1c are the most reasonable
  - Option 1b preferable because zones could still meet renewable mandates/goals
- Option 1d and 1e are less reasonable
  - Combining approaches, or combining results from different runs to determine benefits, is asking for trouble, and can lead to final results that are less sound

Recommendation

- **Staff recommends Option 1b: Move Wind to Zonal Load Centers for addressing the Trapped Generation Pockets Issue**
  - **Addresses the issue**
  - **Most technically sound alternative**

LOAD POCKETS

Load Pockets Approaches

- Option 2a: Status Quo
  - Results in excessive emergency gen, breaching constraints in base case, leading to inflated APC benefit
- Option 2b: Add load pocket upgrades to base case
- Option 2c: Add CTs in base case
- Option 2d: Add CTs in base case, include capital costs
- Option 2e: Add CTs and CCs in base case
- Option 2f: Add single resource to load pocket, distributed proportionally among load buses

- Today: Staff and ABB thoughts and recommendation, get input from stakeholders

Option 2b: Add load pocket upgrades to base case

These upgrades would be in base and change cases.

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Easy to implement
- Consistent generation assumptions between base and change cases

Cons:

- Understates benefit - ignores any economic benefit of the load pocket upgrades
  - In this case, all load pocket upgrades are classified as reliability

Option 2c: Add CTs in base case

Add CT resources in the load pocket for the base case only

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load
- Shows the load pocket upgrades having some economic benefit, which is expected

Cons:

- Inconsistent generation assumptions between base and change cases

Option 2d: Add CTs in base case, include capital costs

Add CT resources in the load pocket for the base case only, include the capital costs of these resources as an adder to the base case APC

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load
- Shows the load pocket upgrades having some economic benefit, which is expected
- Accounts for capital costs of new resources that would be needed in theoretical base case scenario

Cons:

- Inconsistent generation assumptions between base and change cases
- Complexity
- Mixing capital costs in with APC calculation can be tricky – it is expanding the scope of what APC benefit was intended to capture

Option 2e: Add CTs and CCs in base case

Add CT and CC resources in the load pocket for the base case only

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load
  - Real-world situation could include some mix of CCs/CTs
- Shows the load pocket upgrades having some economic benefit, which is expected

Cons:

- Inconsistent generation assumptions between base and change cases
- Adding lower cost CCs to load pocket could mask some of the economic benefit to be gained by new load pocket upgrades
- Increased complexity in determining how many CCs vs CTs to add, and vetting
- Doesn't account for CCs being less likely additions because of higher capital costs

Option 2f: Add single resource to load pocket, distributed proportionally among load buses

This was an idea from ABB. Distribution of resource based on magnitude of individual loads. Resource would have no fuel, emissions, or hourly profile, but just a VOM = curtailment price = $X.

Pros:

- Addresses the Load Pocket issue; results are more reasonable than the Status Quo
- Shows the load pocket upgrades having some economic benefit, which is expected
- Technically sound – in this theoretical base case situation, adding resources would be most reasonable way to serve remote load. This is more of a modeling technique than a real-world implementation, but it effectively models new generation and the associated production costs.
- Slightly better control of the "trigger price" for new generation dispatch

Cons:

- Inconsistent generation assumptions between base and change cases
- Need to determine what X is (not too high, not too low)

Recommendation

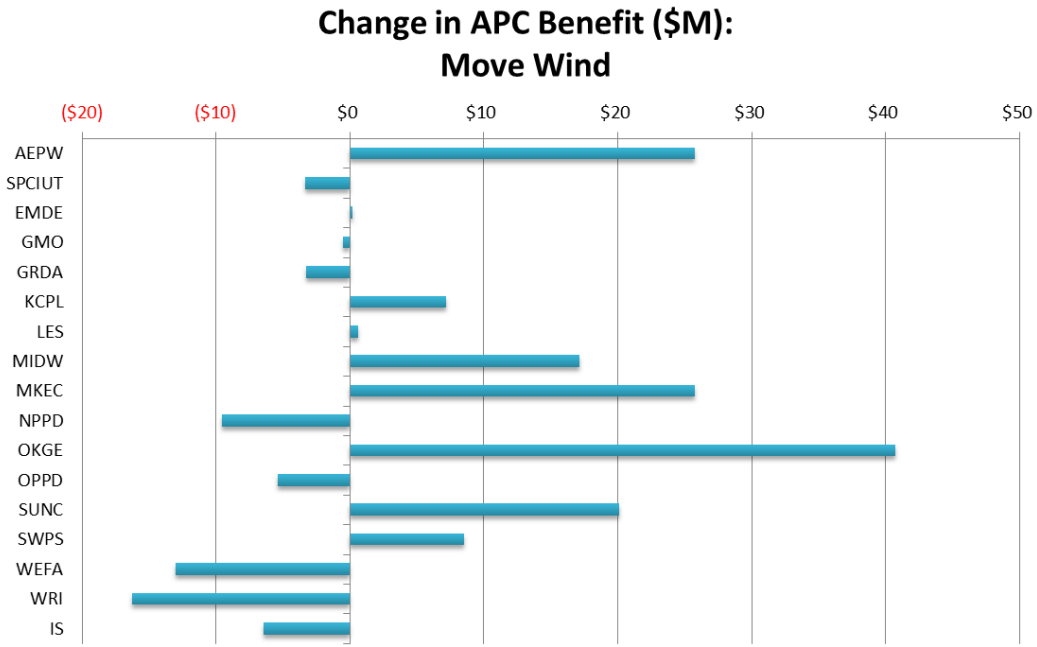
- **Staff recommends Option 2c: Add CTs in base case for addressing the Load Pockets issue**
  - **Technically sound**
  - **Reasonable results – don't appear too high or too low**
  - **Previously approved by ESWG**
  - **Option 2f (single resource) is a close second**

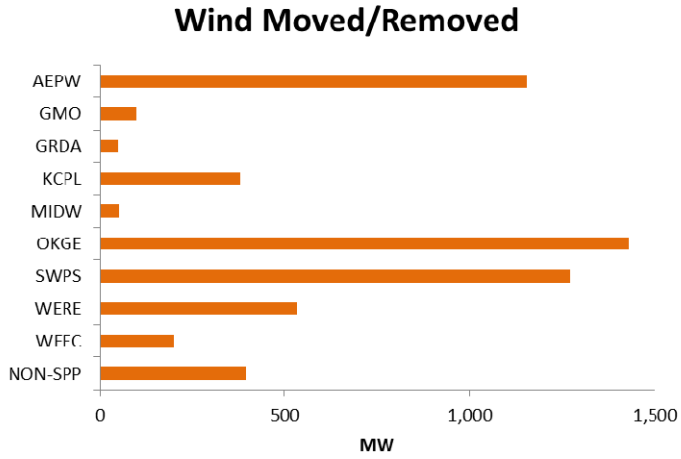
Next Steps

- Staff would like to finalize approaches to these modeling issues by October 22
  - November 18 is drop dead date

APPENDIX

Option 1b: Move Wind to Zonal Load Centers

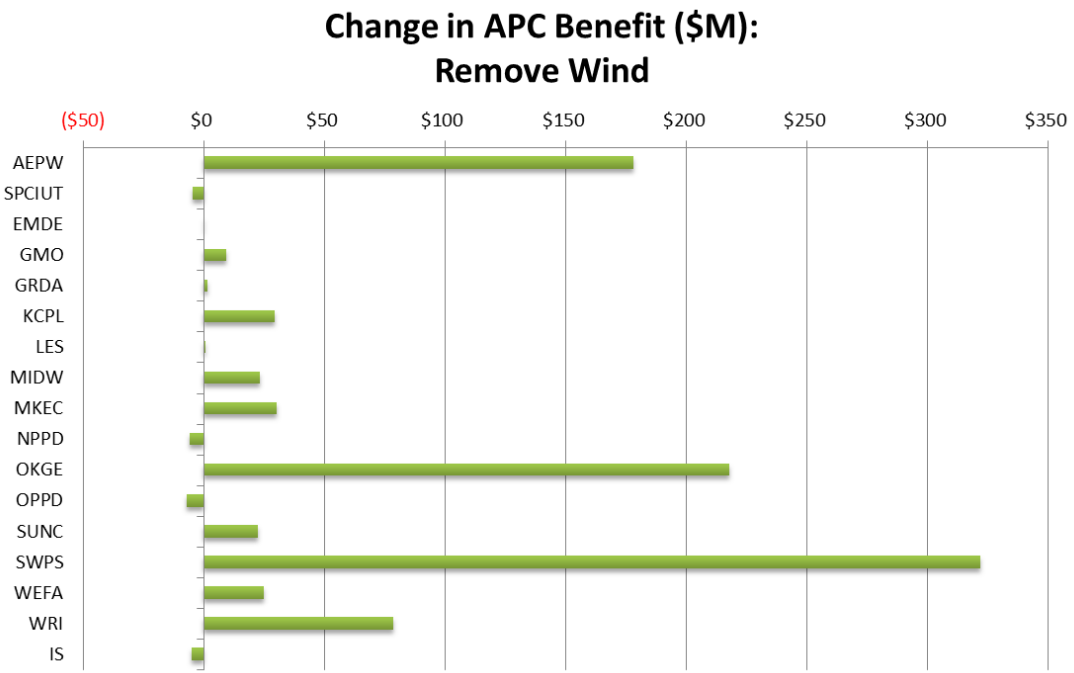


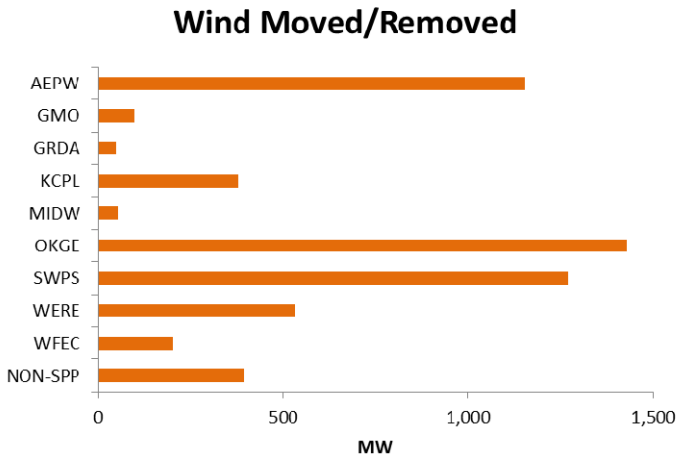


Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

Option 1c: Remove Wind

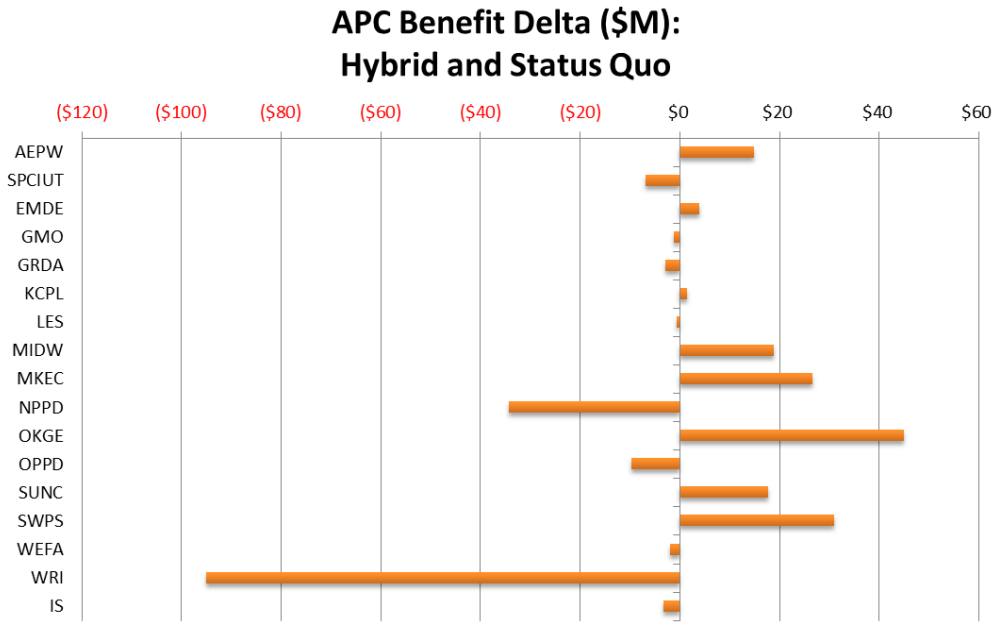


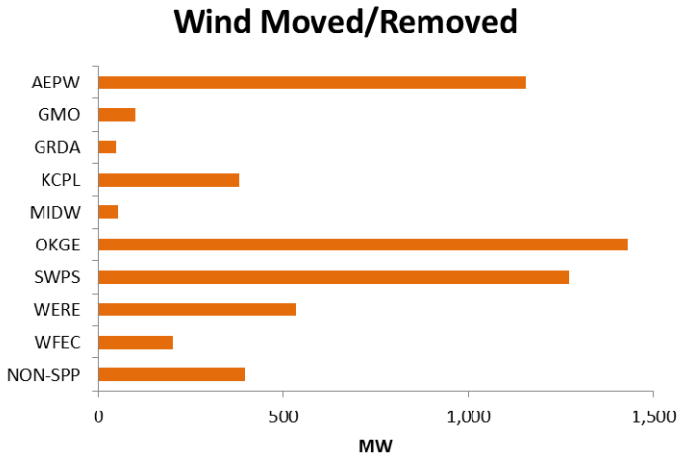


Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

Option 1d: Hybrid Approach





Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

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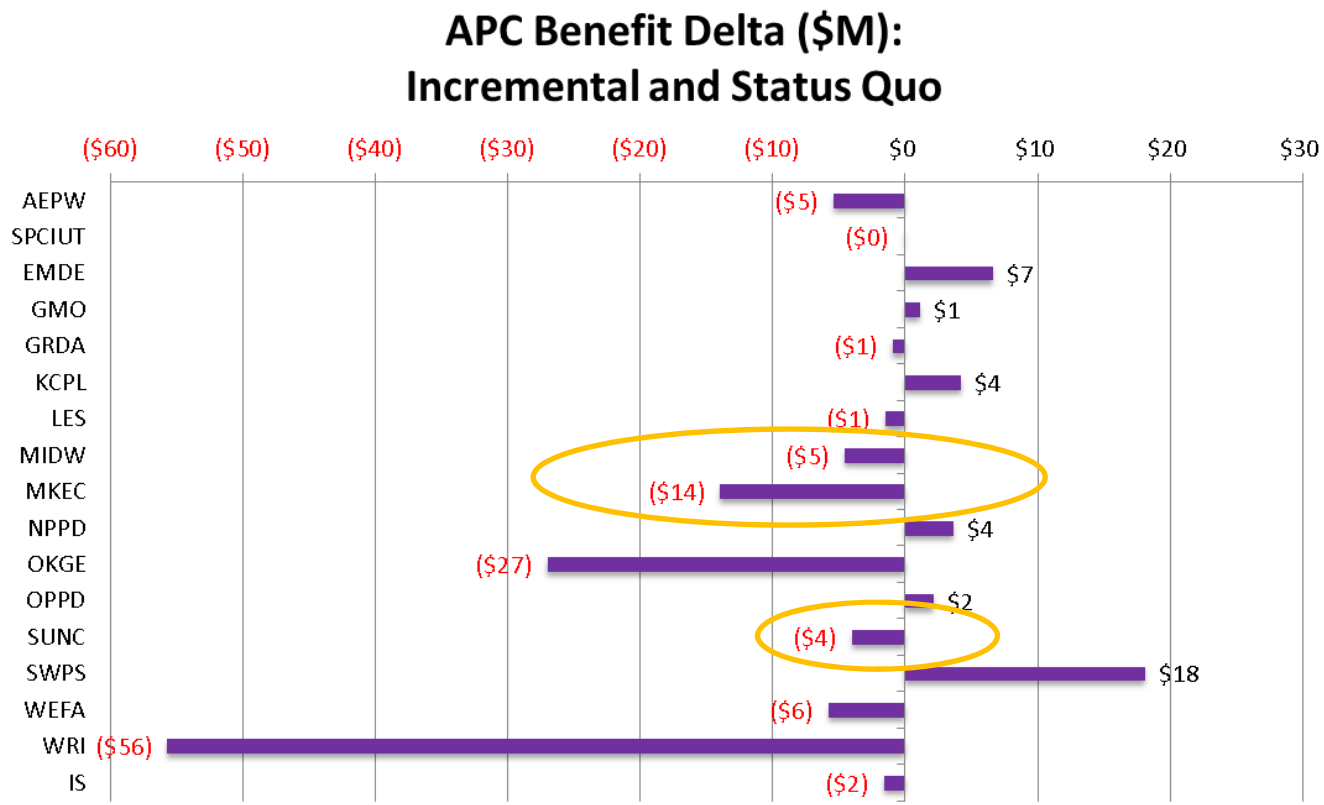
Option 1e: Incremental Approach

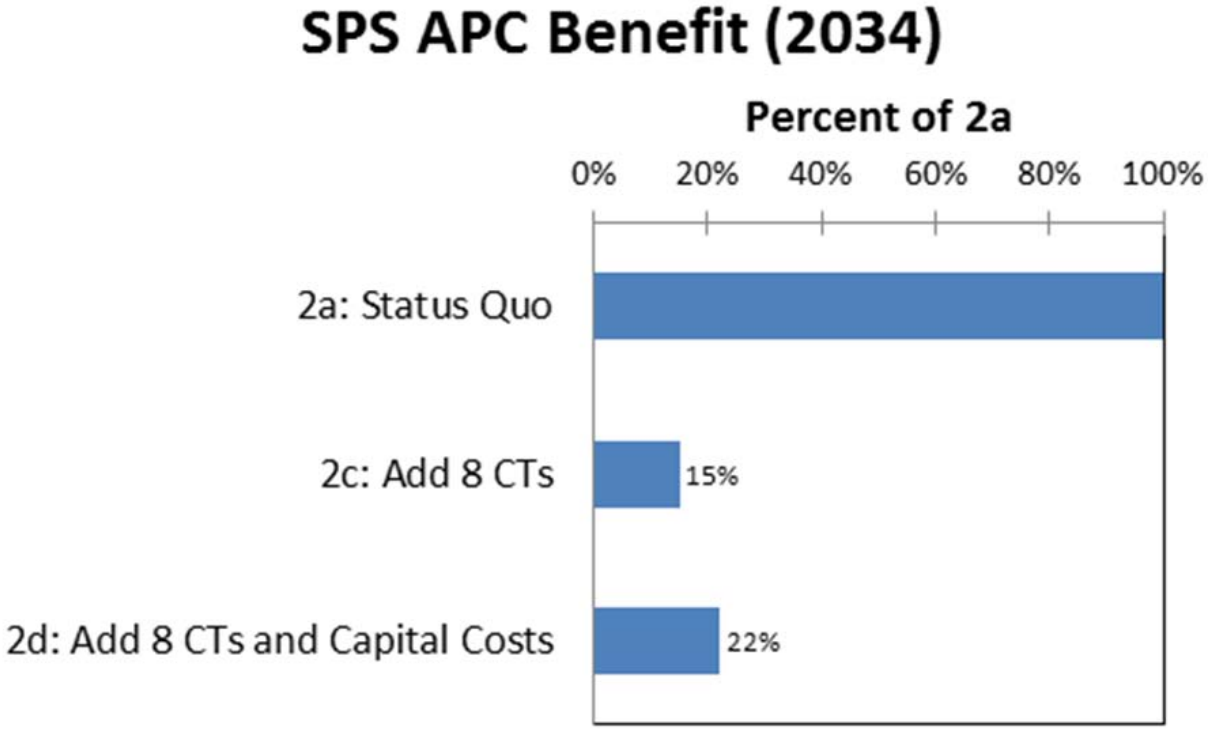


Graph compares APC benefit with this approach to APC benefit obtained with Status Quo approach. Positive means benefit is higher with this approach.

Results based on preliminary RCAR II models built on 2015 ITP10 models; final RCAR II models will be built on 2017 ITP10 models.

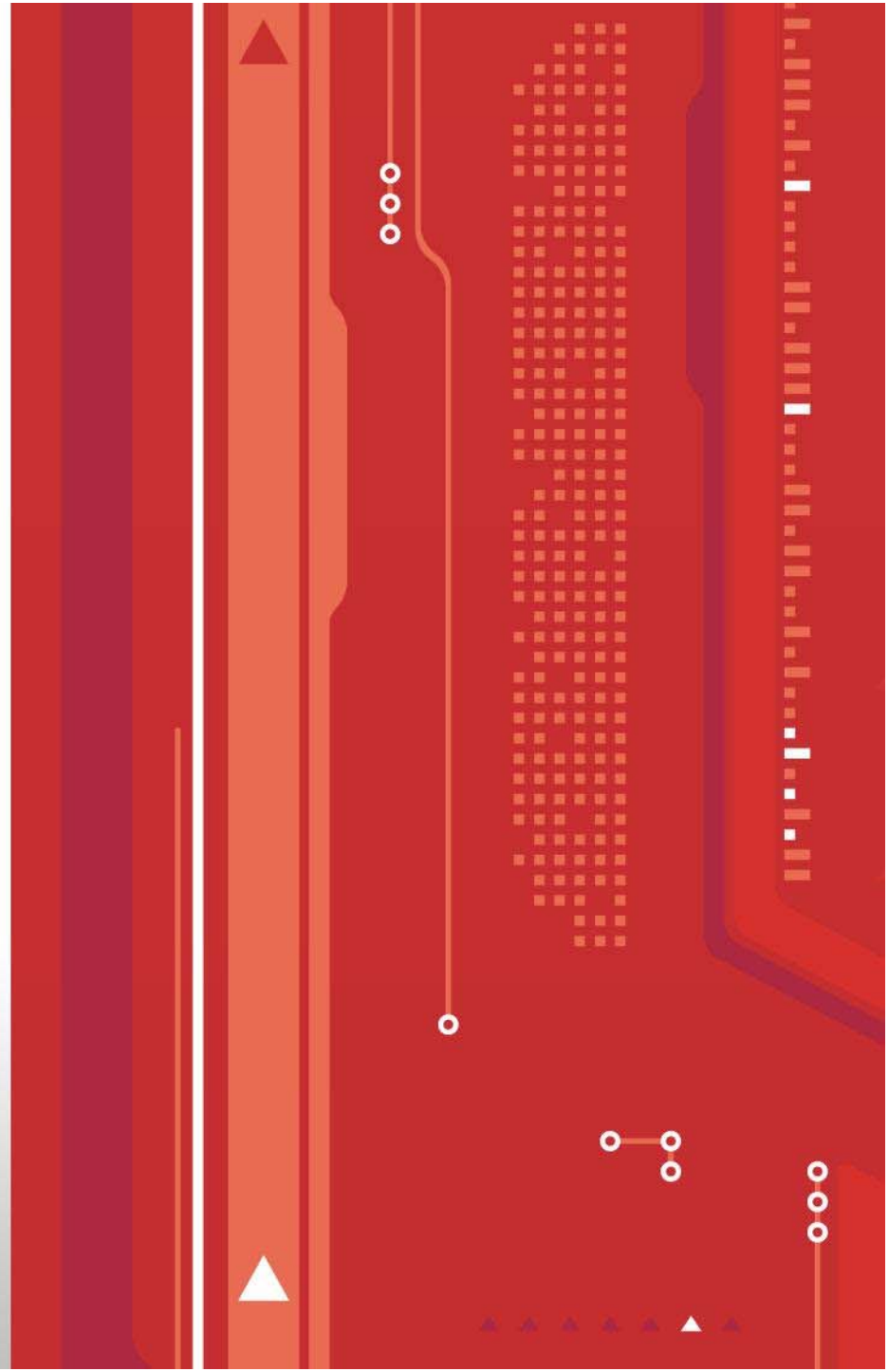
Load Pocket Solutions

- Options 2c and 2d effectively address the emergency generation and breaching constraint problems



Non-Transmission Solution Evaluation Proposal

August 20th, 2015
ESWG



What Does The Tariff Say?

Attachment O Section III 8.d

In addition to recommended upgrades, the Transmission Provider will consider, on a comparable basis, any alternative proposals which could include, but would not be limited to, generation options, demand response programs, "smart grid" technologies, and energy efficiency programs. Solutions will be evaluated against each other based on a comparison of their relative effectiveness of performance and economics.

Process Goals

- **Evaluate the use of a Non-Transmission Solution (NTS) fairly/equally against transmission solutions**
  - **NTSs may not always be the best solution or vice versa**
  - **Develop common process to evaluate non-transmission solutions vs. transmission solutions**
    - **Process may differ slightly between ITPNT and ITP10 evaluation**
- **Find the best solution for the identified study needs as well as future system needs**
- **Apply evaluation approach to ITP and TSS processes**

Non-Transmission Solution

- **What is a NTS?**
  - **Opening a line**
  - **Closing a line**
  - **Generation dispatch (MW or MVAR)**
  - **Operation of other existing equipment such as cap banks, transformers, or other equipment**
  - **Future generation**
  - **Demand-side management**

Transmission Operating Guides

- **SPP will evaluate TOGs as NTSs if submitted through RMS during the DPP window**
- **SPP may develop and/or test additional TOGs not submitted through the DPP window**

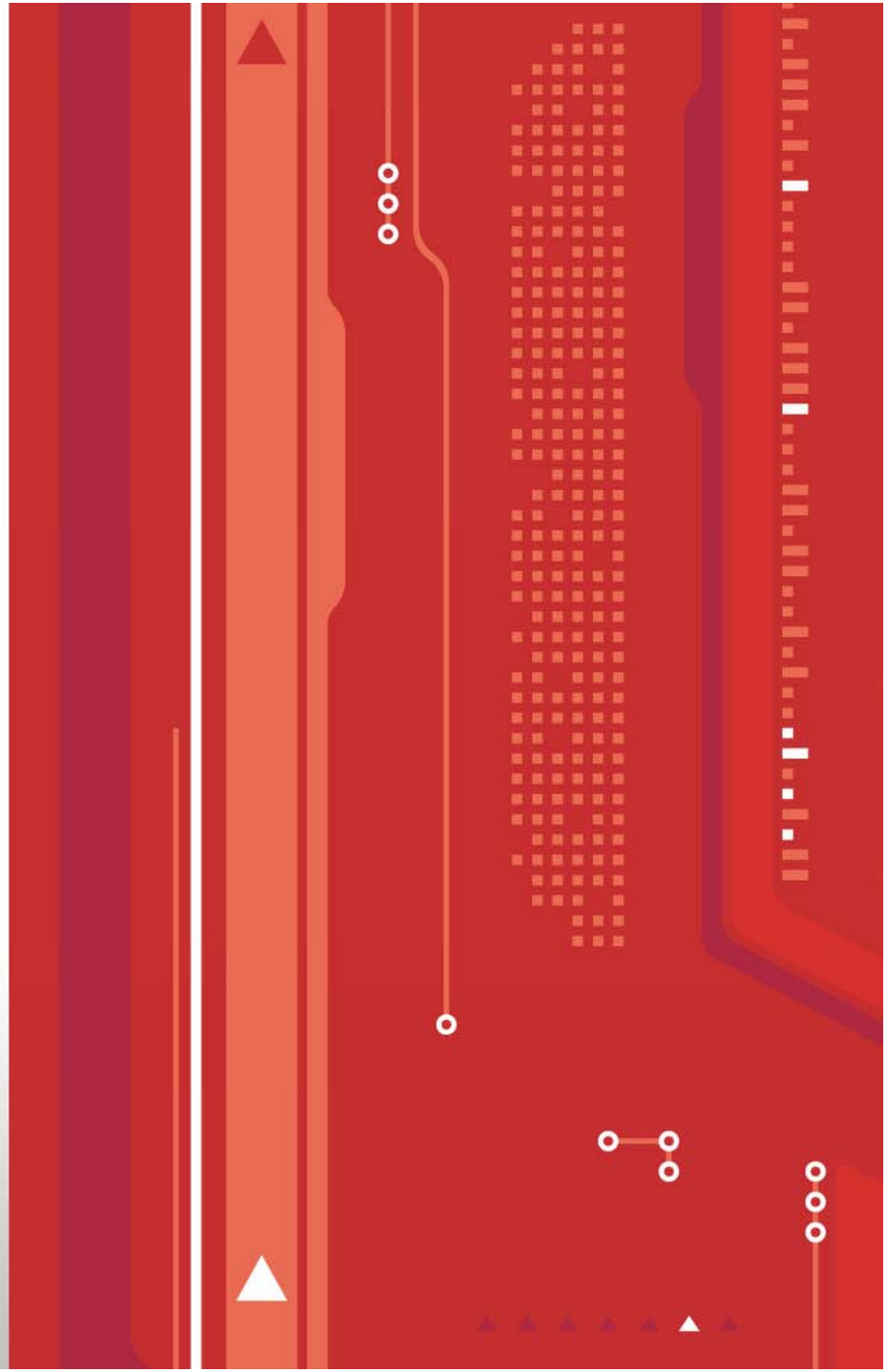
Submitting a NTS through Order 1000

- All NTSs submitted as DPPs
- DPP must include as applicable:
  - NTS Description
  - System conditions for application
  - Needs solved
  - Detailed Operator Actions
  - Expected life
  - Exceptions
  - Idev/Nomogram and PROMOD case
  - Risk Assessment

MOPC Action Item #255

August 19th, 2015

ESWG



SPP Southwest Power Pool

MOPC Action Item #255

- Review the method to determine the Cost of Congestion as it relates to Outages for Rebuilds approved
- Assigned to Staff January, 2015
- Seeking ESWG input

ESWG Discussion 7/9

- There is a cost we're not capturing
  - How do you measure it?
  - How impactful is it in assessing overall benefits?
- Other type of line outage costs we do not capture
  - No stochastic line outages in our models now
  - Transmission lines are taken out many times over their life and we do not capture those costs
- Are these just transactional costs?
  - Not costs associated with long run use of a new (rebuilt) line

Other Considerations

- Typical outage costs could be assessed but would be equivalent for all projects studied
- Is there a need to account for these costs in project development phase?
  - Fully assess the impacts a single project has over another, from a cost and benefit perspective
  - Typically only select economic projects based on APC
  - Is this considered another metric for project selection?
- Potential impacts on reliability project selection?

Studying Congestion Impacts

- What should be modeled for duration of the line outage?
- How does the congestion cost factor into an equivalent 1-year cost of a comparative transmission project?