Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 12th, 2014

AEP Offices – Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. Staff will present the results of the hybrid methodology proposed by Brattle for the Mandated Reliability Projects metric at the June 24th meeting.
2. ESWG members approved the items 3b and 3c in the consent agenda.
3. ESWG members will have a conference call on June 19th to discuss the Public Policy metric.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

June 12th, 2014

AEP Offices – Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 9:32 AM, welcomed those in attendance, and asked for introductions. (Attachment 1 – Attendance List)

There were 28 in person participants and 26 web conference participants representing 11 of 13 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP Staff) reviewed proxy statements. One proxy was identified. Kip Fox (AEP Transource) named Jim Jacoby as his proxy. (Attachment 2 – Proxies)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 3 – Agenda)

> **A motion to approve the agenda was made by Kurt Stradley (LES) and seconded by Tim Owens (NPPD). The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Juliano Freitas (SPP Staff) recapped the pending action item list and asked for additional updates or changes (Attachment 4 – Past Action Items). No changes or additional updates were provided.

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following items:

a. Approval of Meetings Minutes – April 3rd, 2014 (Attachment 5 – 20140403 ESWG Minutes)
b. Approval of Meeting Minutes – April 10th, 2014 (Attachment 6 – 20140410 ESWG Minutes)
c. Approval of Meeting Minutes – April 24th, 2014 (Attachment 7 – 20140424 ESWG Minutes)

Tim Owens (NPPD) requested that the April 3rd minutes be pulled from the consent agenda so that comments submitted on votes would be properly reflected. The minutes for the April 10th and April 24th meetings were approved unanimously.

Agenda Item 4 – 2015 ITP10 Schedule

Antoine Lucas (SPP Staff) gave the group an update on the 2015 ITP10 schedule. Upcoming on the schedule is the initial review of the first part of the report. Antoine stated that some updates on the ITP10 will be reported at the two Summits that will be happening later in 2014. Juliano Freitas (SPP Staff) stated that in addition to everything for the ITP10, the group will soon start to see more on the RCAR II, SPP-MISO CSP, and 2016 ITP20. Some concern as to whether another ITP20 study would be conducted, Lanny Nickell (SPP Staff) answered that reconsideration of the ITP process is a strategic initiative in the

Revised Strategic Plan that will be assigned to the MOPC. (Attachment 8 – 20140612 2015 ITP10 Schedule)

Agenda Item 5 – Metrics Review

Antoine Lucas (SPP Staff) and Hannes Pfeifenberger (The Brattle Group) presented the benefit metrics to the ESWG. For the Mandated Reliability Projects metric, although the DFAX methodology hasn't been the most popular, Hannes suggested that if DFAX were to be used, including wind should be considered at least to the extent that it is included in the reliability analysis. In addition to the 4 allocation methodologies that had been presented to the group previously, load-ratio share (LRS) was added. Some members weren't keen on the idea of LRS because that was the reason there are inequities in the first place. Hannes stated that The Brattle Group was in support of SPP's recommendation to the group, but there is really no wrong way to allocate these benefits. The methodology proposed by SPP Staff is trying to extract the best of each methodology, LRS seems to allocate better benefits when high voltage projects are analyzed, in the other hand, the System Reconfiguration captures better the benefits in low voltage systems. A straw poll was taken to get a feel for where the group stood on the metric:

1. SPP recommendation – 4 votes
2. Proctor recommendation – 0 votes
3. LODF/SR – 3 votes (plus 2 non-voting members)

Nextera Energy abstained their vote. AEP/Transource did not have a final position about their vote, possibly proposing a new methodology in the next meeting.

After more discussion, and the tendency of members to get away from the LRS approach, Hannes suggested the following allocation methodology:

- >300 kV projects: 1/3 SR, 2/3 LRS
- 100-300 kV projects: 2/3 SR, 1/3 LRS
- <100 kV projects: all SR

(Attachment 9 – 20140612 Status of SPP Metrics Review and Recommendation_DRAFT v7)

ACTION ITEM: Members requested to see the implications of this proposed methodology at the June 24th meeting.

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 3:25 p.m.

Respectfully Submitted,

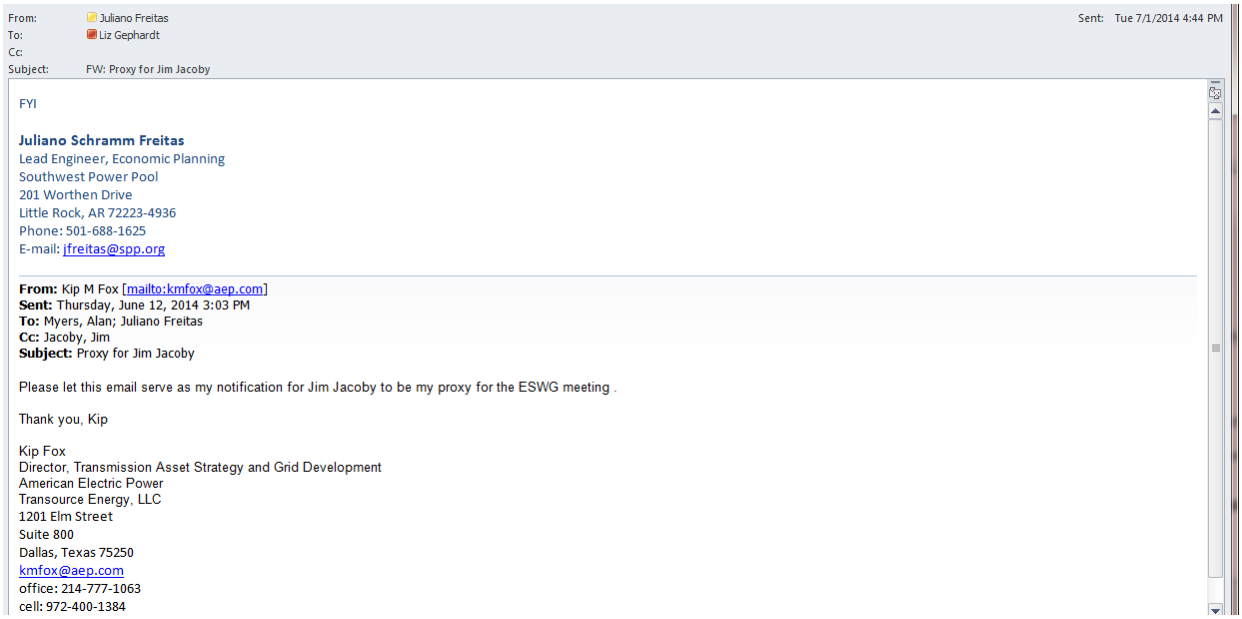
Juliano Freitas

ESWG Secretary

Name	Attendance
Aaron Doll (EDE)	WebEx
Al Tamimi	WebEx
Alan Meyers (ITCGP)	In person
Amber Greb	WebEx
Anita	WebEx
Antoine Lucas (SPP Staff)	In person
Bennie Weeks (XCEL/SPS)	In person
Bill Leung (NPRB)	WebEx
Bruce Walkup (AECC)	WebEx
Caitlin Shank	WebEx
Cindy Ireland (AR PSC)	WebEx
Dallas Rippy	WebEx
Dan Jones, SPP	WebEx
Deral Danis (Clean Line)	WebEx
Don Frerking (KCP&L)	WebEx
Don Le	WebEx
ed pfeiffer (quanta)	WebEx
Gayle Freier (SPP)	WebEx
Heather Starnes (CU/MJMEUC)	WebEx
Jason Chaplin (OCC)	WebEx
Jason Shook (GDS/ETEC)	WebEx
Jeff Knottek	WebEx
Jeremy Harris (Westar)	WebEx
Jeremy Severson (BEPC)	WebEx
Jerry Bradshaw	WebEx
Jim Jacoby (AEP)	In person
Joe Lang	WebEx
Johannes Pfeifenberger (Brattle Group)	In person
John Allen	WebEx
John Boshears	WebEx
Jon Iverson	WebEx
Jon Shipman (OPPD)	WebEx
Jordan Schmick	WebEx
Josh Eckerman	WebEx
Josh Ross	WebEx
Joshua Eckerman	WebEx
Juliano Freitas (SPP Staff)	In person
Katherine Prewitt (staff)	WebEx
Kaustubh Deshmukh	WebEx
Kelsey Allen (SPP Staff)	In person
Kip Fox (AEP)	WebEx
Kurt Stradley (LES)	In person
Liz Gephardt (SPP)	WebEx
Meena Thomas (Texas PUC)	In person
Michael Odom (SPP)	WebEx
Michael Watt (OMPA)	WebEx

Mike Knapp (OCC)	WebEx
Mike Proctor	WebEx
Nathan McNeil	WebEx
Nicole King	WebEx
Noumvi Ghomsi	WebEx
Olu Fagbemiro (BMcD)	WebEx
Onur Aydin (Brattle Group)	In person
Pat Hayes (Ameren)	In person
Pat McCool	In person
Ralph Luciani	WebEx
Randy Collier (CUS)	WebEx
Robert Safuto (Customized Energy Solutions)	WebEx
Rosemary Mittal	WebEx
Sam Loudenslager (SPP)	WebEx
Shawnee Claiborn-Pinto	WebEx
Steve Gaw	WebEx
Terri Gallup (AEP)	WebEx
Thanh Tran (BMcD)	WebEx
Tim Owens (NPPD)	In person
Tim Soles (Occidental)	WebEx

Kip Fox (AEP Transource) proxy to Jim Jacoby.



From: Juliano Freitas
To: Liz Gephardt
Cc:
Subject: FW: Proxy for Jim Jacoby
Sent: Tue 7/1/2014 4:44 PM

FYI

Juliano Schramm Freitas
Lead Engineer, Economic Planning
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: 501-688-1625
E-mail: jfreitas@spp.org

From: Kip M Fox [mailto:kmfox@aep.com]
Sent: Thursday, June 12, 2014 3:03 PM
To: Myers, Alan; Juliano Freitas
Cc: Jacoby, Jim
Subject: Proxy for Jim Jacoby

Please let this email serve as my notification for Jim Jacoby to be my proxy for the ESWG meeting .

Thank you, Kip

Kip Fox
Director, Transmission Asset Strategy and Grid Development
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Transource Energy, LLC
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cell: 972-400-1384

ECONOMIC STUDIES WORKING GROUP

June 12th , 2014

AEP Offices, Dallas, TX

• A G E N D A •

9:30 pm – 3:30 pm

1. Administrative items
    a. Call to Order, Introductions ..... Alan Myers (5 minutes)
    b. Receipt of Proxies ..... Juliano Freitas (1 minute)
    c. Review of Agenda ..... Alan Myers (1 minute)
2. Review of Past Action Items ..... Juliano Freitas (10 minutes)
3. Consent Agenda (Approval Item)[i] ..... Alan Myers (10 minutes)
    a. Approval of Meetings Minutes – April 3rd, 2014
    b. Approval of Meeting Minutes – April 10th, 2014
    c. Approval of Meeting Minutes – April 24th, 2014
    d. Approval of Meetings Minutes – May 21st & May 22nd, 2014
4. 2015 ITP10 Schedule ..... Antoine Lucas (20 minutes)
5. Metrics Review ..... SPP Staff/Brattle (5 hours)
6. Closing Items ..... All

[i] Background Materials Included

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

May 21st, 2014

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.	Aug 23, 2012 ESWG	In Progress Staff	Staff will provide a draft report in November 2014. Staff recommends a discussion during the ESWG meetings in the previous months.
076	ESWG will analyze the aggregate studies impact on the 2015 ITP10 study for transmission service request	May 16, 2013	In Progress ESWG Members	Item on hold, wait for Aggregate Studies new results
087	ESWG members and SPP Staff will compare the generation resources in the different models used in the SPP studies processes	August 13' 2013	In Progress	
101	ESWG to provide wording for Solutions recommendation of the Scope by April 2014 MOPC	October 15-16, 2013 MOPC	Complete	
102	ESWG/TWG finalize the benefits metrics & allocation methods for 2015 ITP10 Portfolio analysis and bring back to April 2014 MOPC	October 15-16, 2013 MOPC	In progress	
104	ESWG members will provide feedback regarding the 2010 Strategic Plan by March 2014	November 21, 2013	Complete	
105	SPP Staff will investigate developing a regular process for economic model development and review.	December 19, 2013	In progress	
107	SPP Staff will develop a detailed draft of the transmission project selection process in the ITP for inclusion in the scope.	December 19, 2013	Complete	
108	SPP Staff will draft "extraordinary circumstances" language for inclusion of projects in the project selection process that do not meet portfolio consolidation criteria.	December 19, 2013	In progress	

110	SPP Staff will review unused metrics developed by the Metrics Task Force (MTF) and bring back background information to the group.	December 19, 2013	Complete	
111	SPP Staff will provide calculation examples to aid in metrics review.	December 19, 2013	In progress	
114	SPP Staff will add the Highway/Byway methodology on the Slide number 24, Metrics Review presentation.	March 13, 2014	Complete	
116	SPP Staff will provide the RCAR schedule	March 13, 2014	Complete	
117	SPP Staff will use the Adding vs Combining methodology to calculate benefits from transmission upgrades and provide feedback to ESWG members.	April 10, 2014	In progress	
118	ESWG Members will review the Tariff language to re-evaluate the ITP Process timeline	April 10, 2014	In progress	
119	SPP Staff will develop a methodology to select Economic Needs.	April 24, 2014	Complete	
120	SPP Staff will provide an example showing how the reliability metric was calculated in the last RCAR	May 21, 2014	In progress	
121	SPP Staff will calculate the R-PLAN APC benefit using the methodology proposed by Mike Proctor (RSC)	May 21, 2014	In progress	
122	SPP Staff will create an example using SPP Staff's proposal and Mike Proctor's proposal regarding the Public Policy Benefits.	May 21, 2014	In progress	

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 3rd, 2014

Web Conference

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will provide more details about the methodology to select economic needs.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 3rd, 2014

Web Conference

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:34 a.m., welcomed those in attendance. (Attachment 1 – Attendance List)

There were 61 web conference participants representing 10 of 11 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP staff) requested proxy statements. One proxy was identified, Kip Fox (AEP-Transource) proxy to Wayman Smith (AEP). (Attachment 2 – Proxies)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 3 – Agenda)

> **A motion to approve the proposed agenda was made by Tim Owens (NPPD) and seconded by Kurt Stradley (LES). The motion was approved unanimously.**

Agenda Item 2 – 2015 ITP10 Schedule

Antoine Lucas (SPP staff) presented the updates in the 2015 ITP10 Schedule, the main issue discussed was the DPP window and when SPP Staff is intending to post the final models. In order to post the model on time to start the DPP window at May 2nd, SPP staff will seek approval of the models by email on April 10th. Some members also are proposing to review the DPP window start datein order to allow more time to review the models and provide a better quality set of solutions to be evaluated by SPP Staff. The delay of the DPP process will have a severe impact on the upcoming milestones; SPP Staff will have to re-evaluate the 2015 ITP10 Study timeline to make sure the study can be done before the January MOPC meeting in 2015. (Attachment 4 – 2015 ITP10 Schedule)

Agenda Item 3 – Metrics Review

Antoine Lucas (SPP Staff) delivered this presentation with the focus on benefit allocation regarding three metrics: assumed benefit of mandated reliability projects, public policy benefits and mitigation of transmission outage costs. Antoine reviewed the straw poll results and also the motions adopted on March 13th during the ESWG meeting. The Assumed Benefit of Mandated Reliability Projects had a motion approved to include the metric and Highway/Byway allocation methodology and improve it as soon as possible. For the Public Policy Benefits, the group had a straw poll in favor of including the metric but have a further discussion regarding project classification.

> **A motion to include the Public Policy Benefit in the 2015 ITP10 Study consistent with the Staff recommended allocation methodology with the ESWG re-evaluating the metric's benefit calculation in order to present it to the MOPC in July 2014 was made by Kip Fox (AEP-Transource) and seconded by Randy Collier (CUS). The motion was approved. Seven members voted yes, two voted no and one abstention.**

For the Mitigation of Transmission Outage Cost metric, the group had a straw poll in favor of including the metric but giving ESWG additional time for further discussion.

A motion to include the Mitigation of Transmission Outage Cost benefit in the 2015 ITP10 Study consistent with the application in the RCAR, with the ESWG continuing to evaluate the metric's benefit allocation in order to present it to the MOPC in July 2014 was made by Tim Owens (NPPD) and seconded by Randy Collier (CUS). The motion was approved. Five members voted yes, four voted no.

In the end of the discussion regarding these last two metrics cited above, members decided to make a motion to include these metrics in the 2015 ITP10 Study. (Attachment 5 – Metrics Review)

A motion to include the Public Policy Benefit and Mitigation of Transmission Outage Cost Benefit metrics in the 2015 ITP10 Study consistent with SPP Staff calculations was made by Kip Fox (AEP-Transource) and seconded by Bennie Weeks (Excel Energy). The motion was approved. Five members voted yes, four voted no.

City Utilities does not support approval of the Increased Wheeling Through and Out Revenues and the Marginal Energy Losses benefit metrics at this time. Our reasons are as follows:

- Staff indicated that Increased Wheeling Through and Out Revenues and the Marginal Energy Losses benefit metrics could be easily calculated. However, no example calculations were presented so City Utilities does not think approval is appropriate without first viewing details of the calculation along with examples.
- City Utilities has a concern that there could be some duplication of benefits by including the Wheeling Through and Out Revenues benefit along with the Point to Point Revenue Credits included in the Regional Cost Allocation Review (RCAR). Without detailed examples of the benefit calculations, we cannot ascertain that there is no duplication of benefits.

Agenda Item 4 – Economic Assessment Areas

Juliano Freitas (SPP Staff) made a brief presentation about the Economic Assessment Areas, SPP Staff had a recommendation to select the economic needs, increasing the original proposed twenty top constraints in the model. The new proposal is to use the top twenty constraints in the SPP area plus the five top in the Integrated System plus the five top in the Seams. ESWG members asked or more time and further evaluation in order to make a decision. (Attachment 6 – Economic Assessment Areas)

Agenda Item 5 – Policy Assessment Criteria

This item was moved to the April 10th ESWG meeting agenda. (Attachment 7 – Policy Needs Assessment)

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 11:14 p.m.

Respectfully Submitted,

Juliano Freitas,

Secretary

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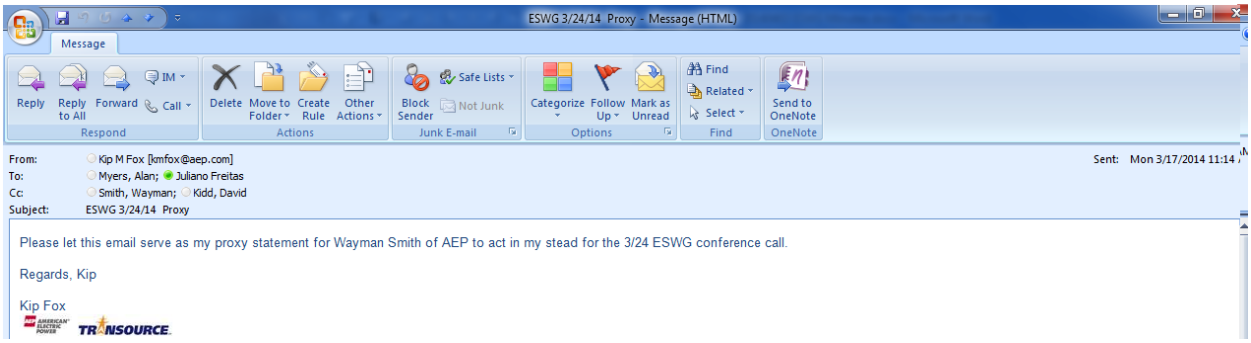
Tim Owens (NPPD)	tjowens@nppd.com
Tim Soles (Occidental)	tim_soles@oxy.com
Wayman Smith (AEP)	wlsmith1@aep.com

Wayman Smith (AEP) will be Kip Fox (AEP-Transource) proxy.



ECONOMIC STUDIES WORKING GROUP

April 3rd, 2014

Conference Call

• A G E N D A •

8:30 am – 11 am

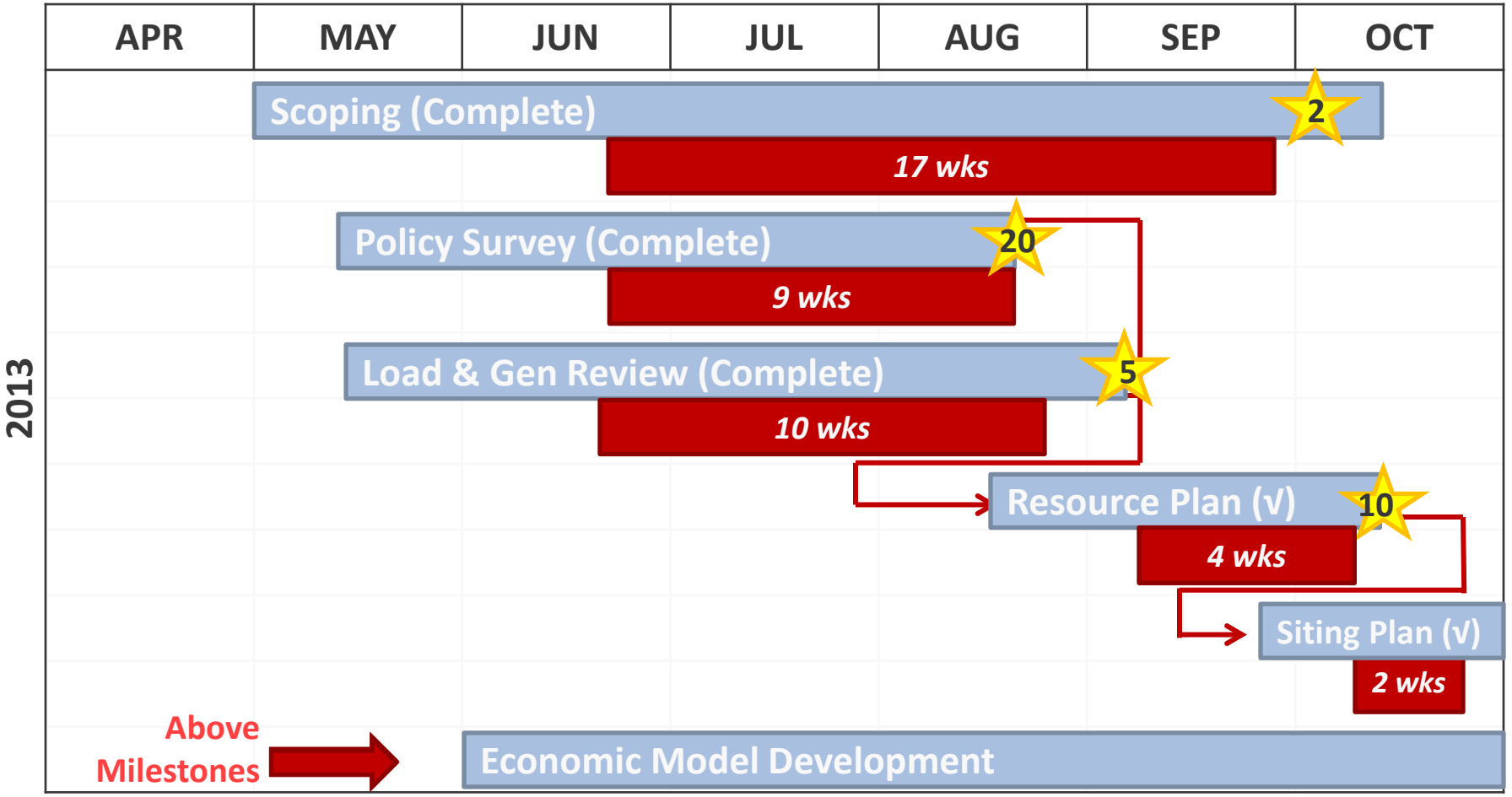
1. Administrative items
    a. Call to Order, Introductions ..... Alan Myers (5 minutes)
    b. Receipt of Proxies ..... Juliano Freitas (1 minute)
    c. Review of Agenda ..... Alan Myers (1 minute)
2. 2015 ITP10 Schedule ..... Antoine Lucas (15 minutes)
3. Metrics Review ..... SPP Staff (1.25 hours)
4. Economic Assessment Areas ..... Juliano Freitas (20 minutes)
5. Policy Assessment Criteria ..... Josh Ross (30 minutes)
6. Closing Items ..... All

2015 ITP10 Schedule

April 3rd, 2014

Southwest Power Pool

ITP10 Milestone Schedule (Apr-Oct 2013)

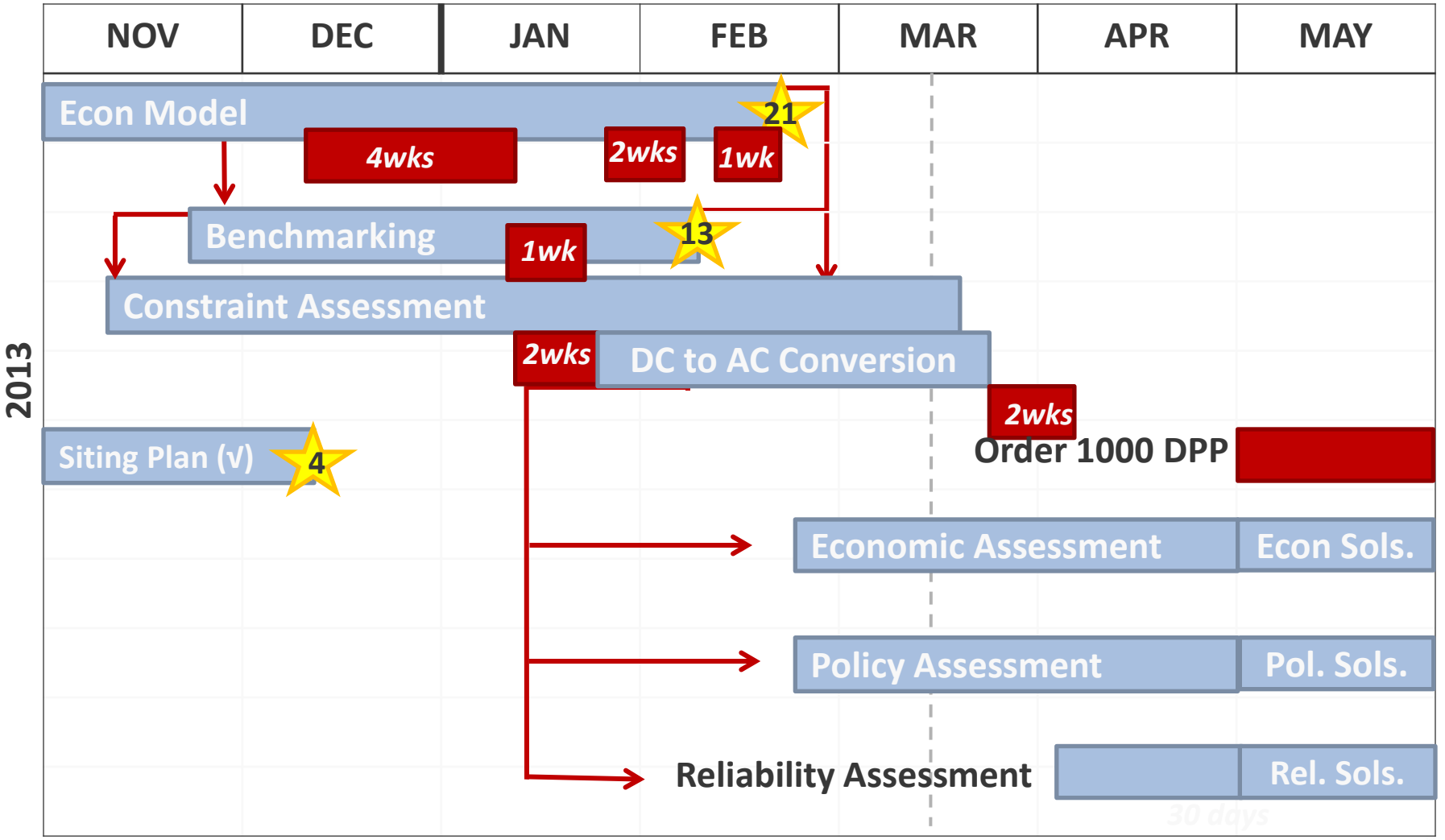


ESWG Approval

Member Review/Feedback Period

Milestone Period

ITP10 Milestone Schedule (Nov 2013-May 2014)

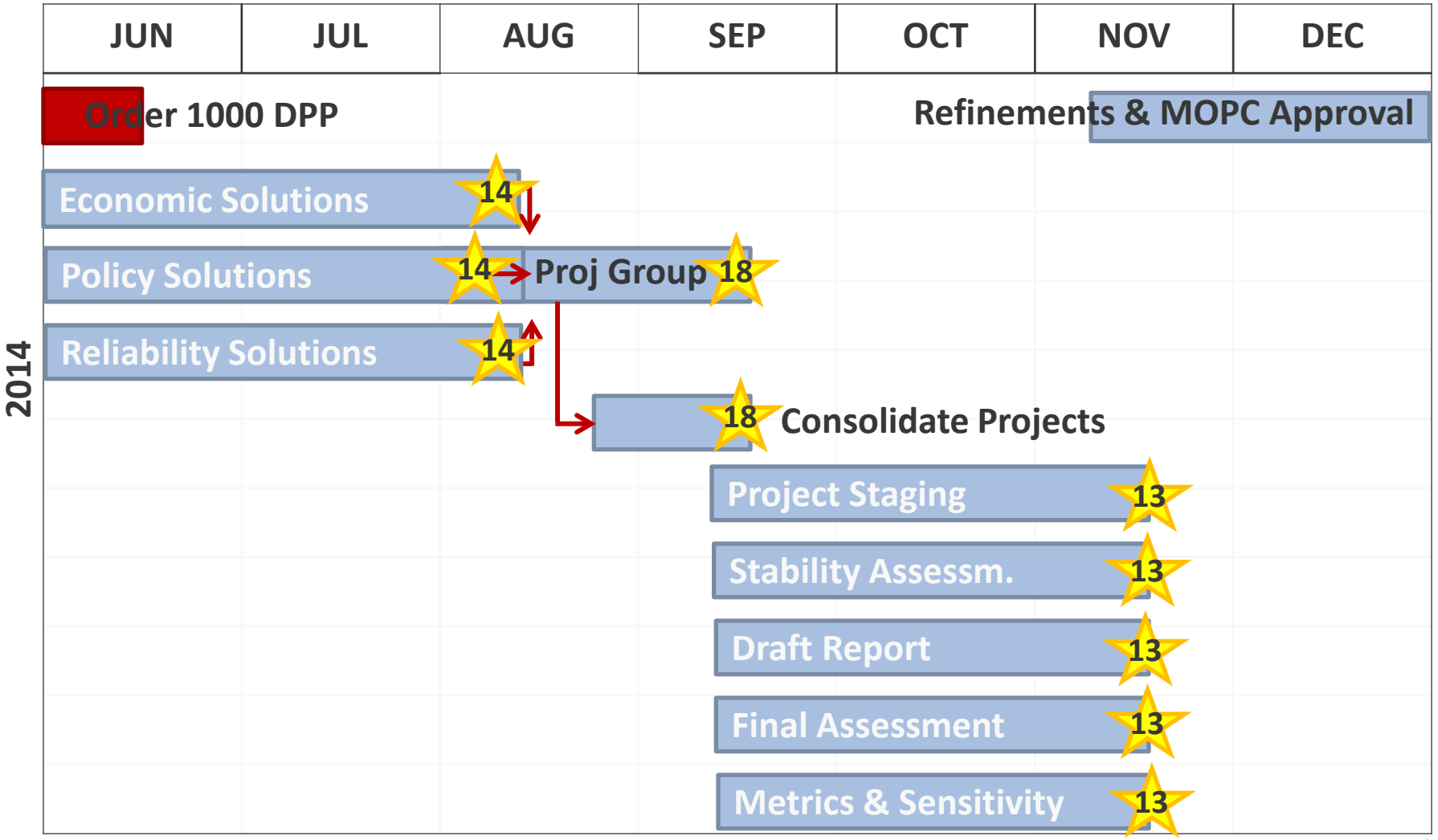


ESWG Approval

Member Review/Feedback Period

Milestone Period

ITP10 Milestone Schedule (Jun-Dec 2014)



ESWG Approval

Member Review/Feedback Period

Milestone Period

ITP10 Milestone Schedule - Summary

Task Name	Start	Finish	Member Feedback	ESWG Approval	
Scoping	April	October	17 weeks	10/2	2013
Policy Survey	May	August	9 weeks	12/04	
Load and Generation Review	May	September	10 weeks	9/5	
Resource Plan	August	October	3 weeks	12/04	
Siting Plan	September	October	2 weeks	12/04	
Economic Model development	June	February	7 weeks	Feb 21/2014	
Benchmarking	November	January '14	1 week	Feb 13/2014	
Constraint assessment - TWG Approval	November	March '14	1 week		
DC to AC Conversion of Peak Hours	January	March	2 weeks		2014
Reliability Assessment	March	May	30 days		
Reliability Solutions	May	July		Aug 14/2014	
Economic assessment	February	May	30 days		
Economic Solutions	April	July		Aug 14/2014	
Policy Assessment	February	May	30 days		
Policy Solutions	April	July		Aug 14/2014	
Stability Assessment	September	October			
Project Grouping	July	August	1 week	Sep 18/2014	
Consolidate Projects	August	September		Sep 18/2014	
Project Staging	September	October		Nov 13/2014	
Draft Report	July	November	3 weeks	Nov 13/2014	
Final Assessment	September	November		Nov 13/2014	
Benefit Calculation	September	November	3 weeks	Nov 13/2014	
Refinements and MOPC Presentation	November	January '15			

Metrics Review

April 10th, 2014

SPP Southwest Power Pool

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

Overview

- **Assumed Benefit of Mandated Reliability Projects**
  - **A straw poll was suggested to identify the members tendency about this metrics, the options were:**
    - 1) Status Quo - include the metric and Highway/Byway allocation methodology
    - 2) Include the metric and give the ESWG more time to evaluate the proposed methodologies;
    - 3) Not include the metric in the 2015 ITP10 Study
  - **The result of the straw poll was: 6 votes for option 1, 2 votes for option 2 and 1 vote for option 3**
  - **A motion to adopt the option 1 (Status Quo) and improve it as soon as possible was made by Paul Dietz (Westar) and seconded by Bennie Weeks (Xcel Energy). The motion was approved, 5 votes in favor and 4 votes against.**

Overview

- **Public Policy Benefits**
  - **A straw poll was suggested to identify the members tendency about this metrics, the options were:**
    - 1) Status Quo
    - 2) Include the metric but further discussion on project classification is needed
    - 3) Adopt the new proposed methodology
    - 4) Not include the metric until the group has a better definition
  - **The option 2 got 6 votes and option 4 got 2 votes. Option 2 won the straw poll.**
  - **Kip Fox (Transource/AEP) made a motion to adopt the option 2 for the 2015 ITP10, but nobody seconded the motion. Motion dismissed.**

Motion

- **Kip fox made a motion to include the Public Policy benefit in the 2015 ITP10 Study consistent with the Staff recommended allocation methodology, the ESWG will re-evaluate the metric benefit calculation in order to present it to the MOPC in July 2014.**

Overview

- **Mitigation of Transmission Outage Cost**
  - **For Mitigation of Outage Costs a straw poll was suggested to identify the member's preference, the options were:**
    - 1) Status Quo (no methodology decided, since this metric was not in the previous ITP10)
    - 2) Include the metric but give ESWG additional time for further discussion;
    - 3) Adopt the new proposed methodology:
      - » a) APC Savings Allocation approach and
      - » b) Historical Outage approach
    - 4) Not include the metric until the group has a better definition
  - **The option 2 got 5 votes and option 3a got 3 votes. Option 2 won the straw poll.**

Motion

- **Tim Owens made a motion to include the Mitigation of Transmission Outage Cost benefit in the 2015 ITP10 Study consistent with the application in the RCAR, the ESWG will continue to evaluate the metric benefit allocation in order to present it to the MOPC in July 2014.**

Approved Metrics for the RCAR

- Adjusted Production Cost (APC) Savings
- Reduction of Emission Rates and Values
- Savings due to Lower Ancillary Service Needs and Production Costs
- Avoided or Delayed Reliability Projects
- Capacity Cost Savings due to Reduced On-Peak Transmission Losses
- Mitigation of Transmission Outage Costs
- Assumed Benefit of Mandated Reliability Projects
- Public Policy Benefits

ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

Reliability Benefit Allocation Methodologies

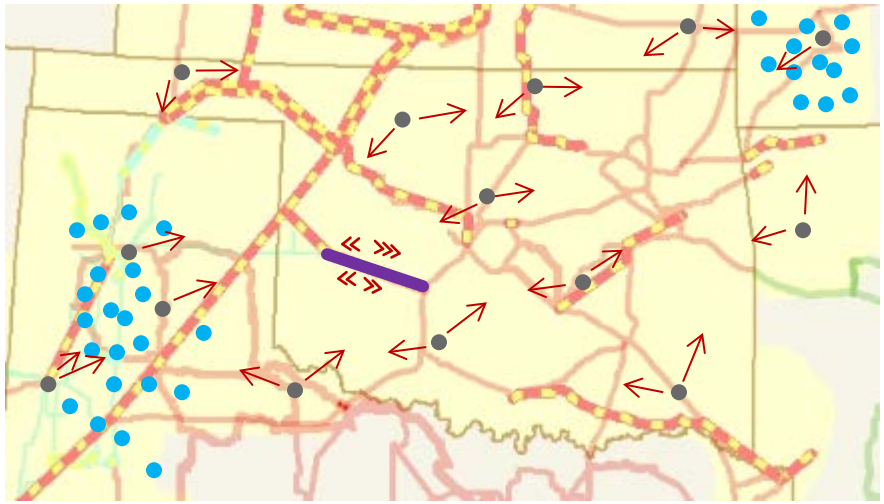
- **Highway/Byway – utilized in RCAR**
- **DFAX**
- **LODF**
- **System Reconfiguration**

*These allocation methodologies do not impact the total reliability benefit of projects. They only impact the allocation of benefit to zones.

DFAX Approach

- Distribution factors (DFAX) used to calculate the portion of a transfer of energy from a defined source to a defined sink that will flow across a specific transmission facility
- A DFAX is calculated for each transmission zone by modeling a transfer from all generation in the SPP region individually to the loads in each transmission zone
- The change in flow for the reliability upgrade was calculated for each of the zonal transfers
- DFAX represent a measure of the use by the load of each transmission zone of the required Reliability Project as determined by power flow analysis

DFAX Approach



Large DFAX -> large benefit

Small DFAX -> small benefit

DFAXs for each of the 16 transfers are normalized to develop allocation factors.

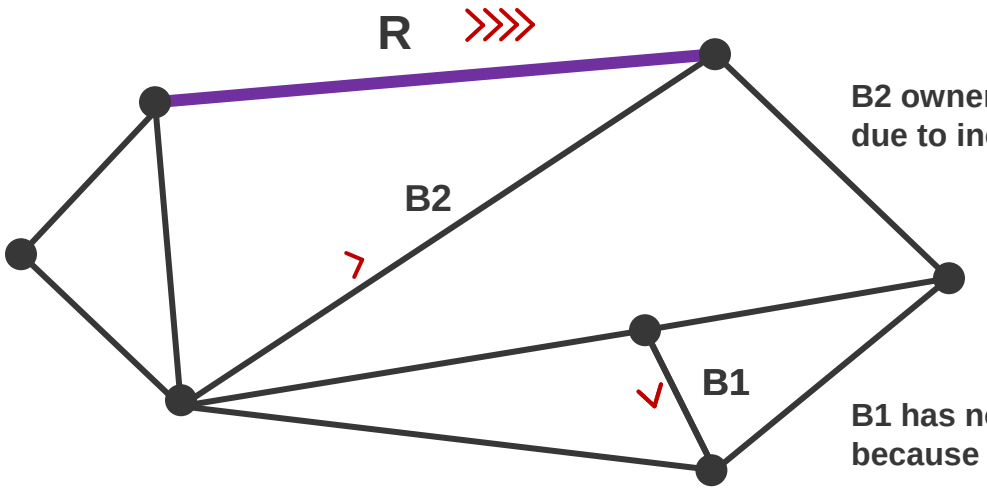
Zones with transfers that impact the reliability upgrade flow the most will have the most benefit.

Line Outage Distribution Factor (LODF) Approach

- N-1 Contingency Analysis
- Change in flow for Reliability Upgrade computed for each outage (LODF)
- Increase in flow for Reliability Upgrade due to Zone A Outage is credited as benefit to Zone A
- Sum of LODFs by zone are normalized to compute allocation factors by zone

LODF Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



B2 owner is assigned benefit, due to increased flow on R

B1 has no impact on benefit, because flow on R stays same

Outage taken for every branch, 1 by 1, and increase in flow on R is measured

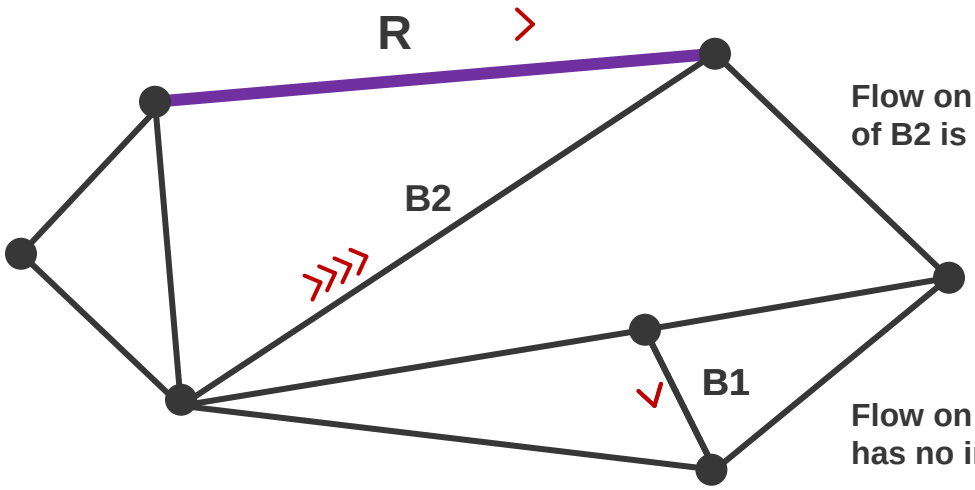
Benefits assigned to zones based on who owns the outaged facilities that cause increases in flow on R

System Reconfiguration Approach

- This approach is modified form of the MW-mile cost allocation utilized prior to Highway/Byway
  - This approach does not utilize line lengths
- Analyze all flows both with and without the reliability upgrade
  - Lines with increased flows after reliability upgrade is outaged are identified as beneficiaries of the reliability upgrade
  - Zones that own these lines are credited with reliability benefit
  - Approach and results are very similar to LODF

System Reconfiguration Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



Flow on B2 increases, owner of B2 is assigned benefit

Flow on B1 stays the same. B1 has no impact on benefit.

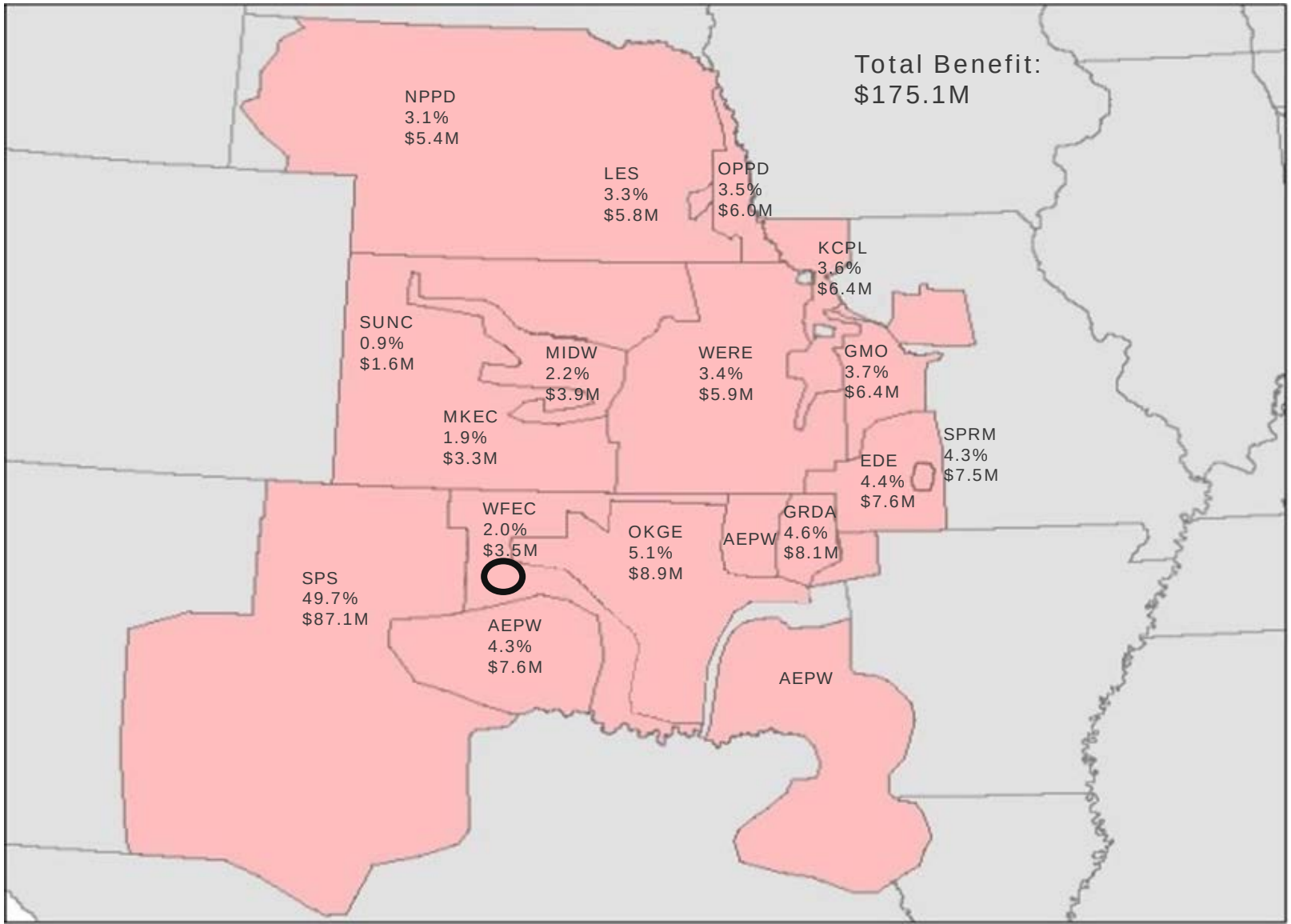
Flow on every branch is analyzed, 1 by 1, to determine if flow increased as a result of R being outaged

Benefit assigned to zones based on who owns the branches with increased flow after R is outaged

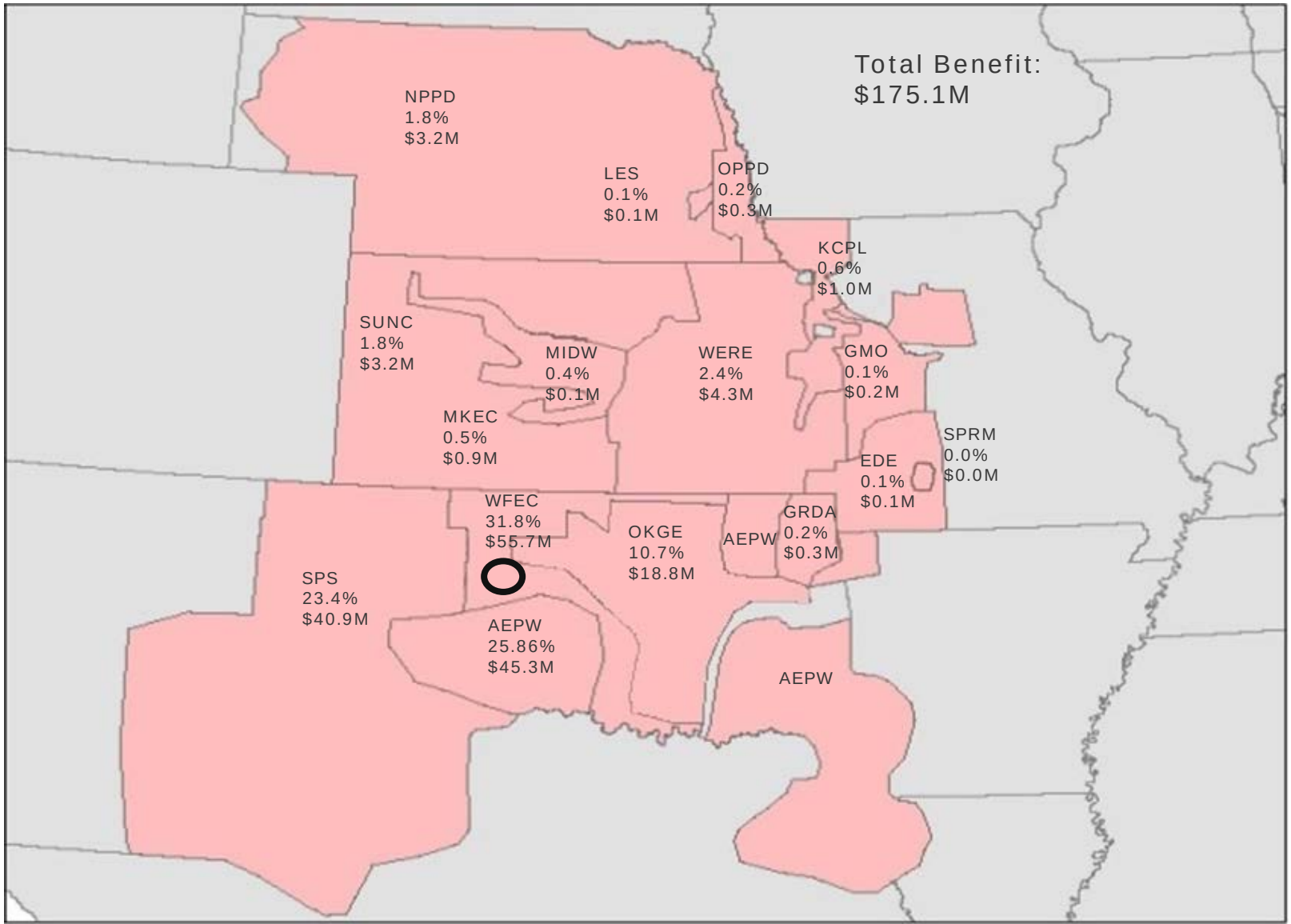
Examples

- Considered three existing reliability projects
  - Summit – Elm Creek 345 (central KS)
  - Elk City – Gracemont 345 (west OK)
  - Oronogo Jct – Riverton 161 (southwest MO)
- For each, compared the benefit allocation results using the different approaches
  - Highway/Byway – used in RCAR
  - DFAX
  - LODF
  - System Reconfiguration

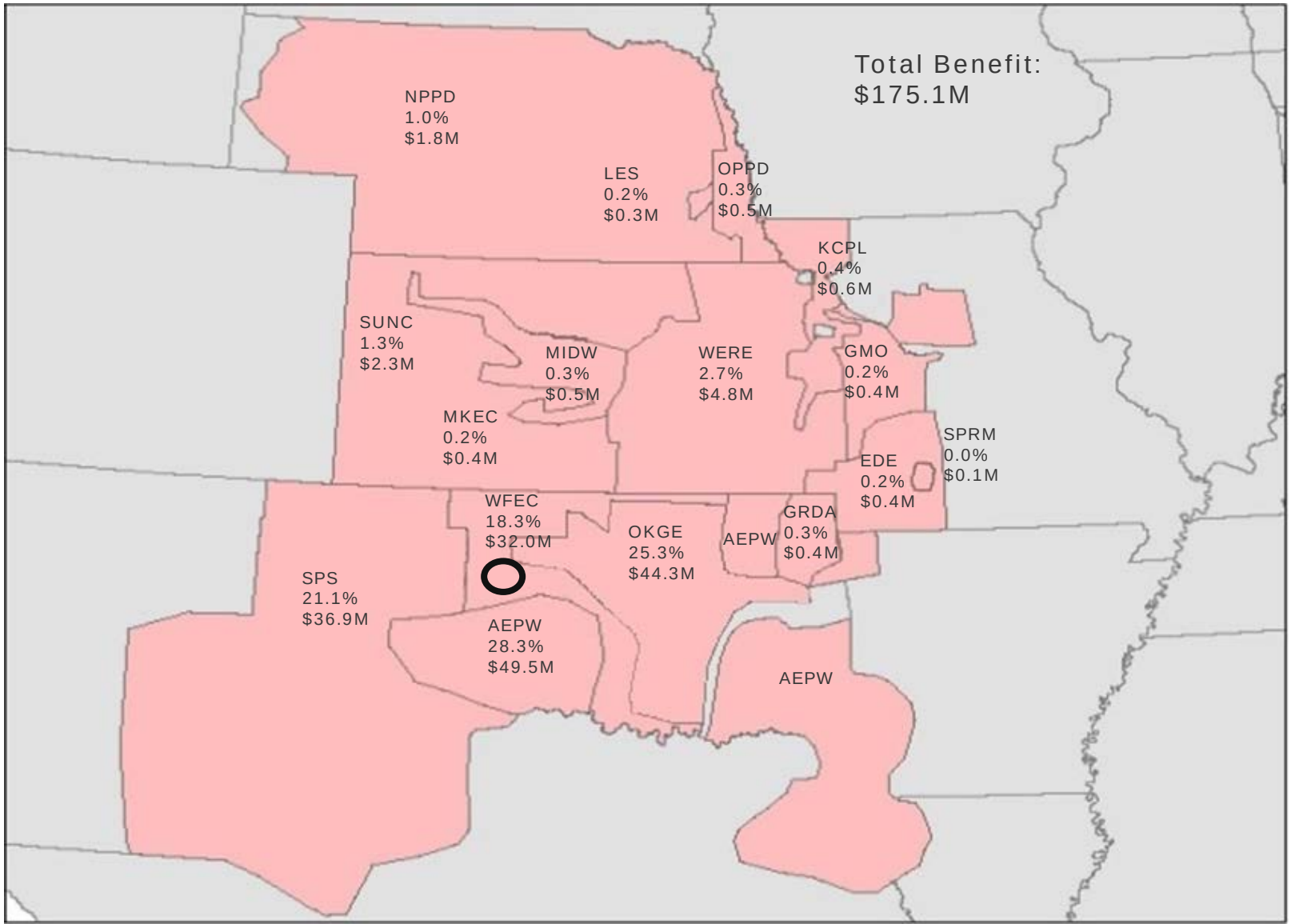
DFAX – Elk City to Gracemont 345 kV



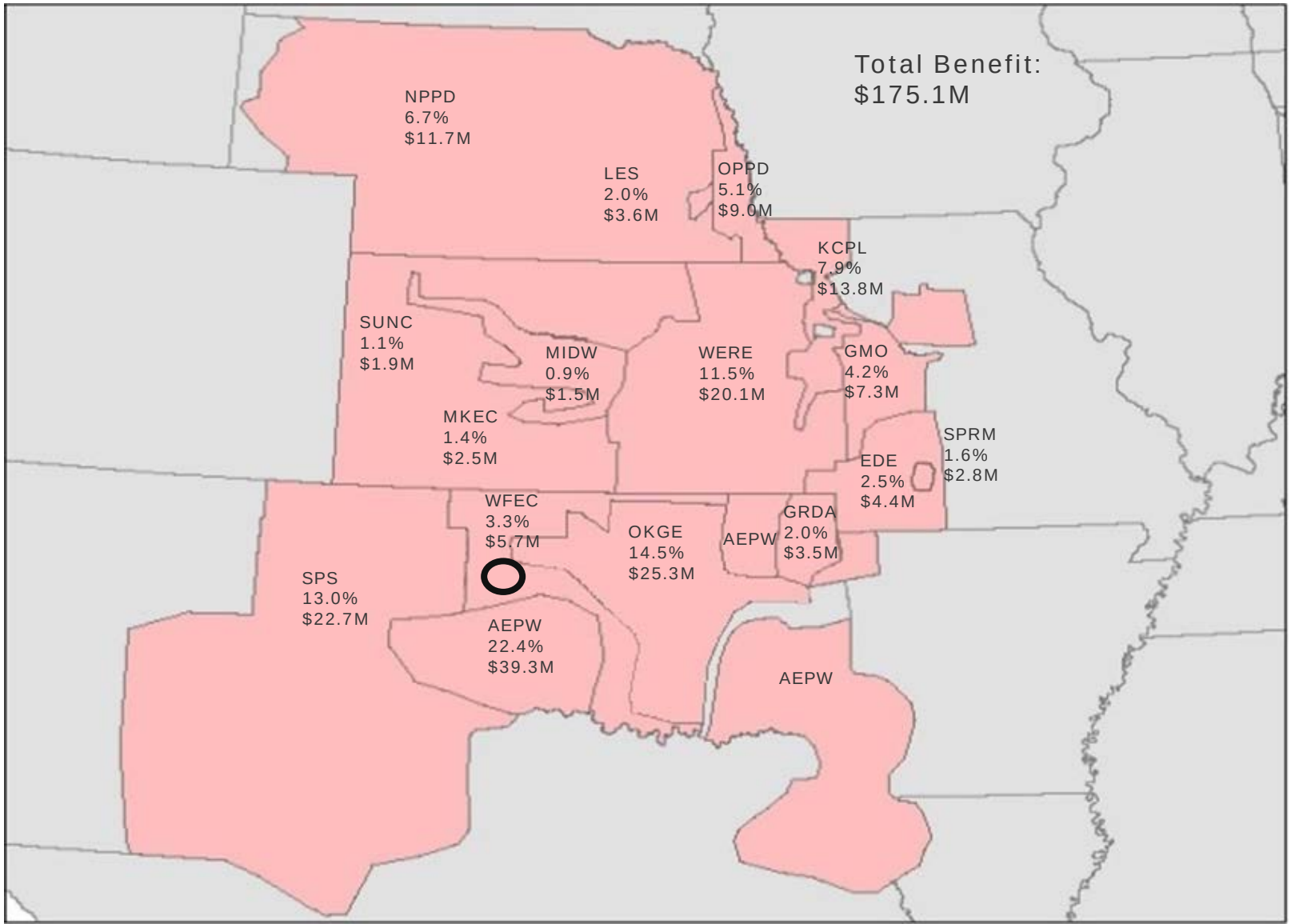
LODF – Elk City to Gracemont 345 kV



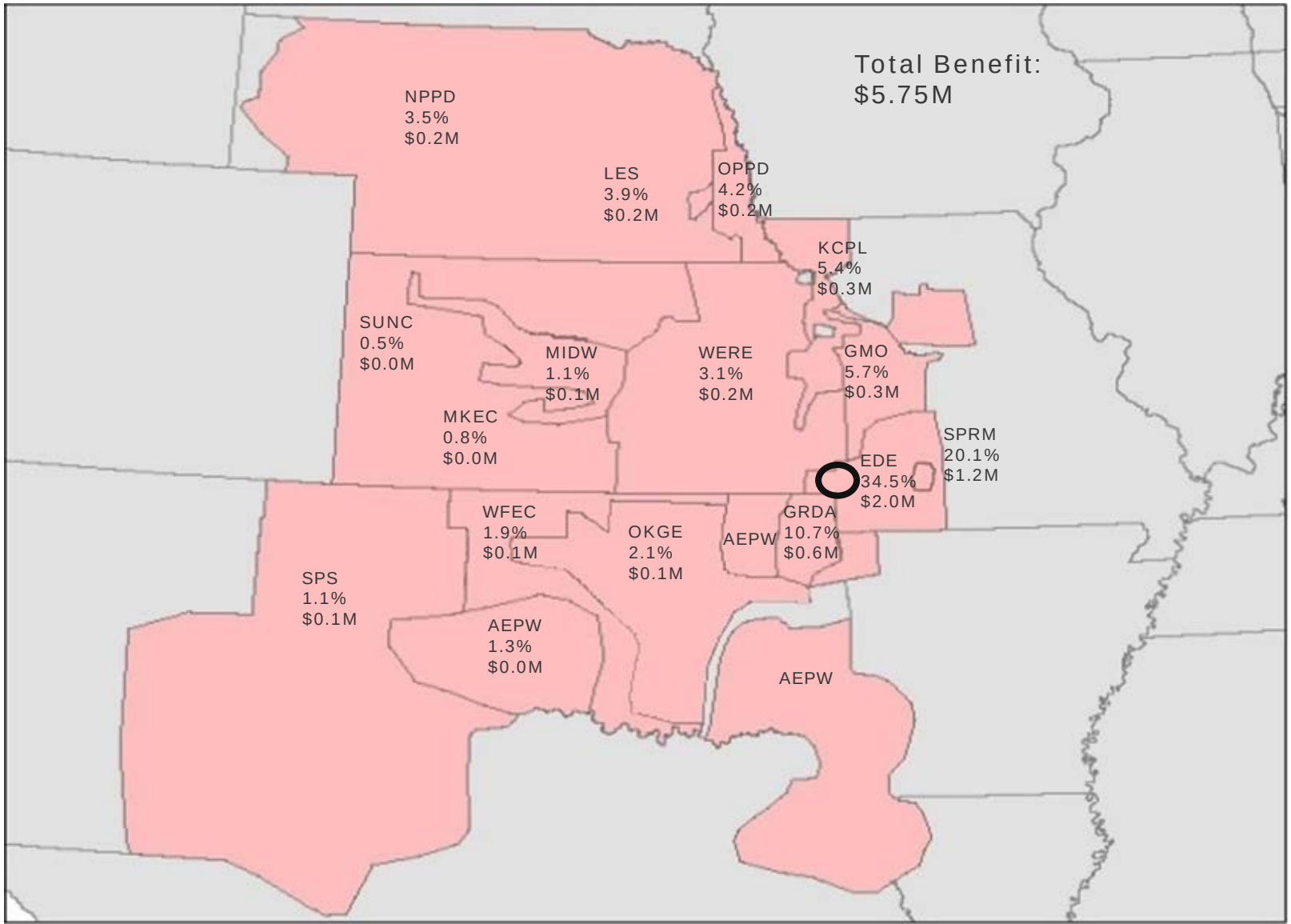
System Reconfiguration – Elk City to Gracemont 345 kV



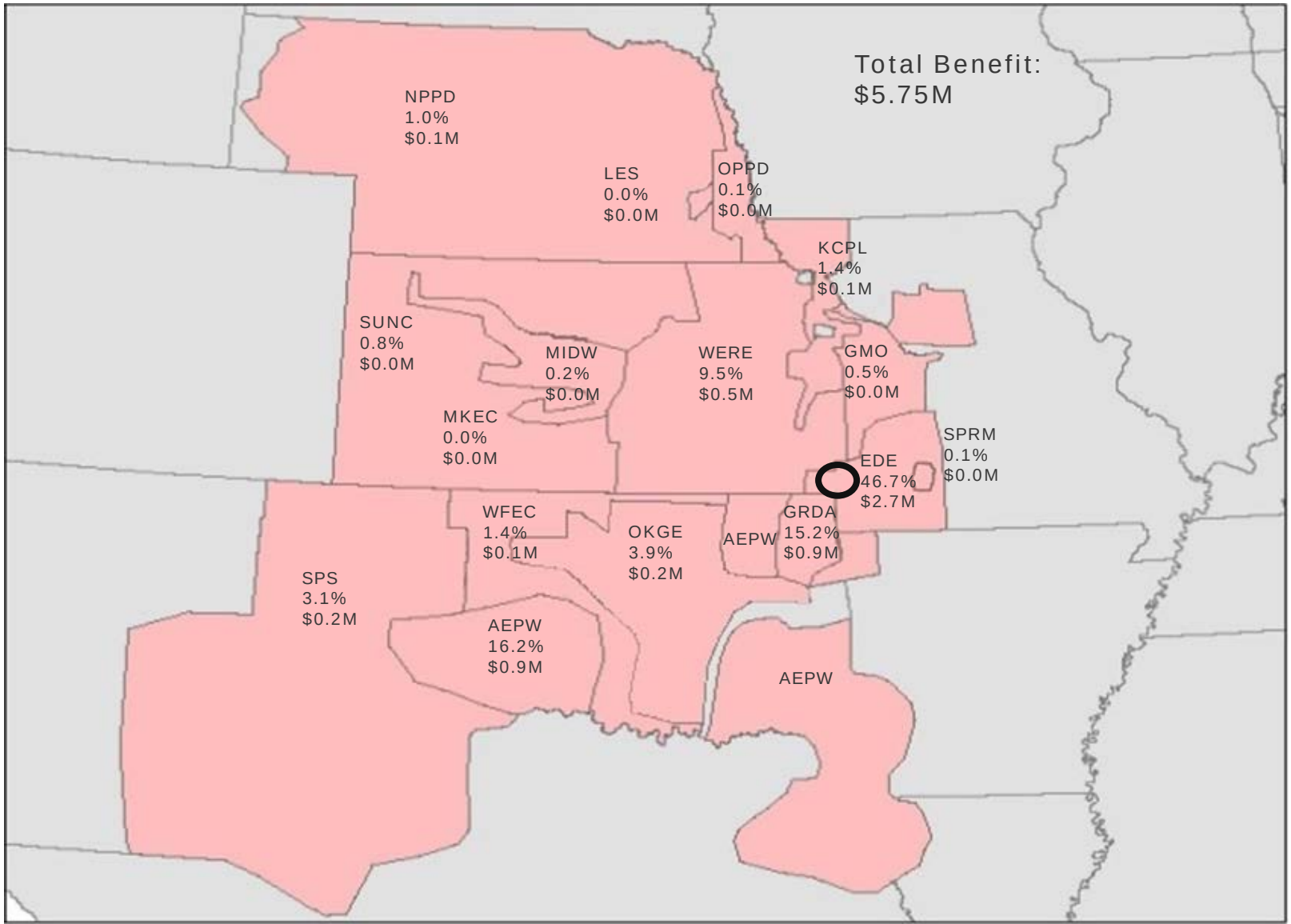
Highway/Byway – Elk City to Gracemont 345 kV



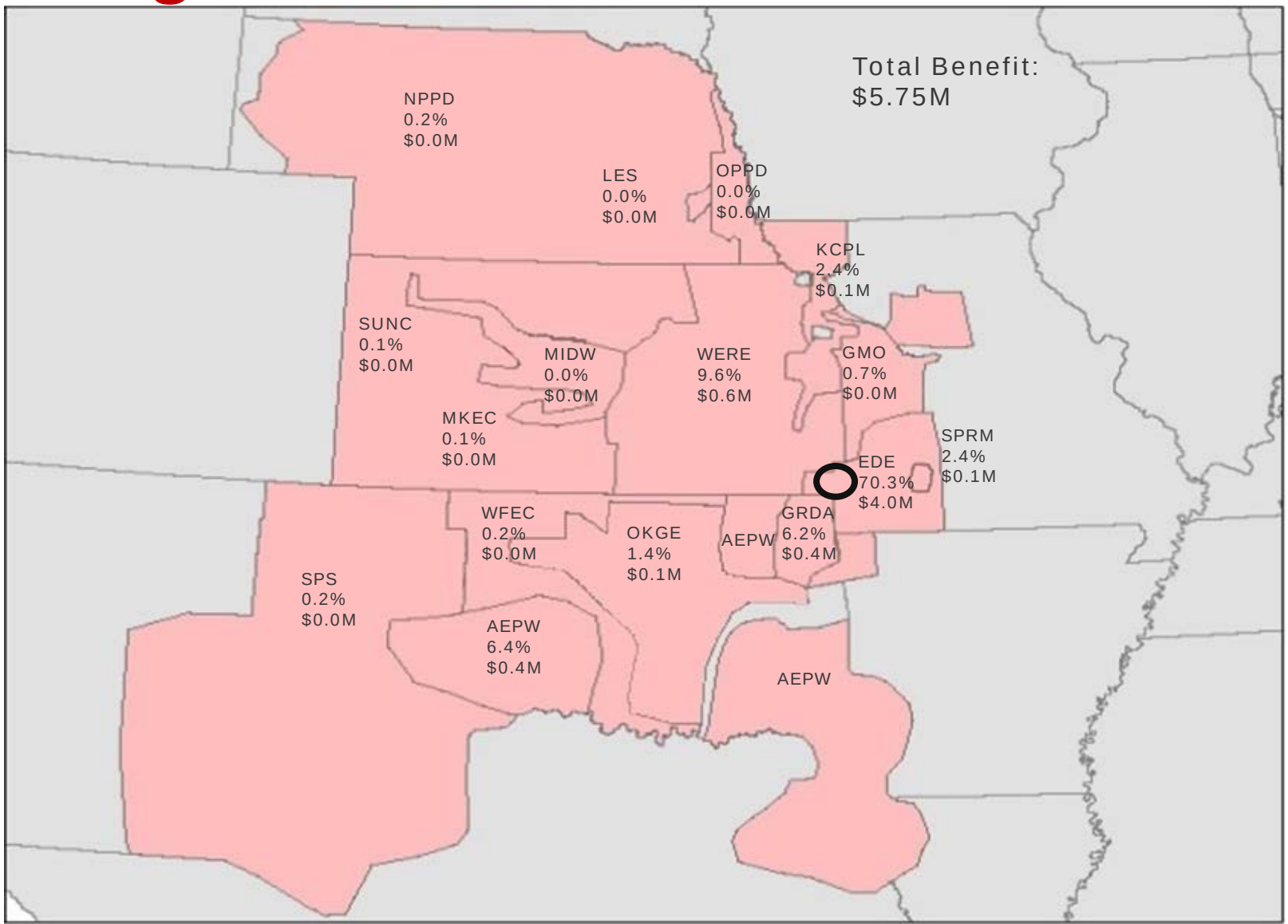
DFAX – Riverton to Oronogo 161 kV



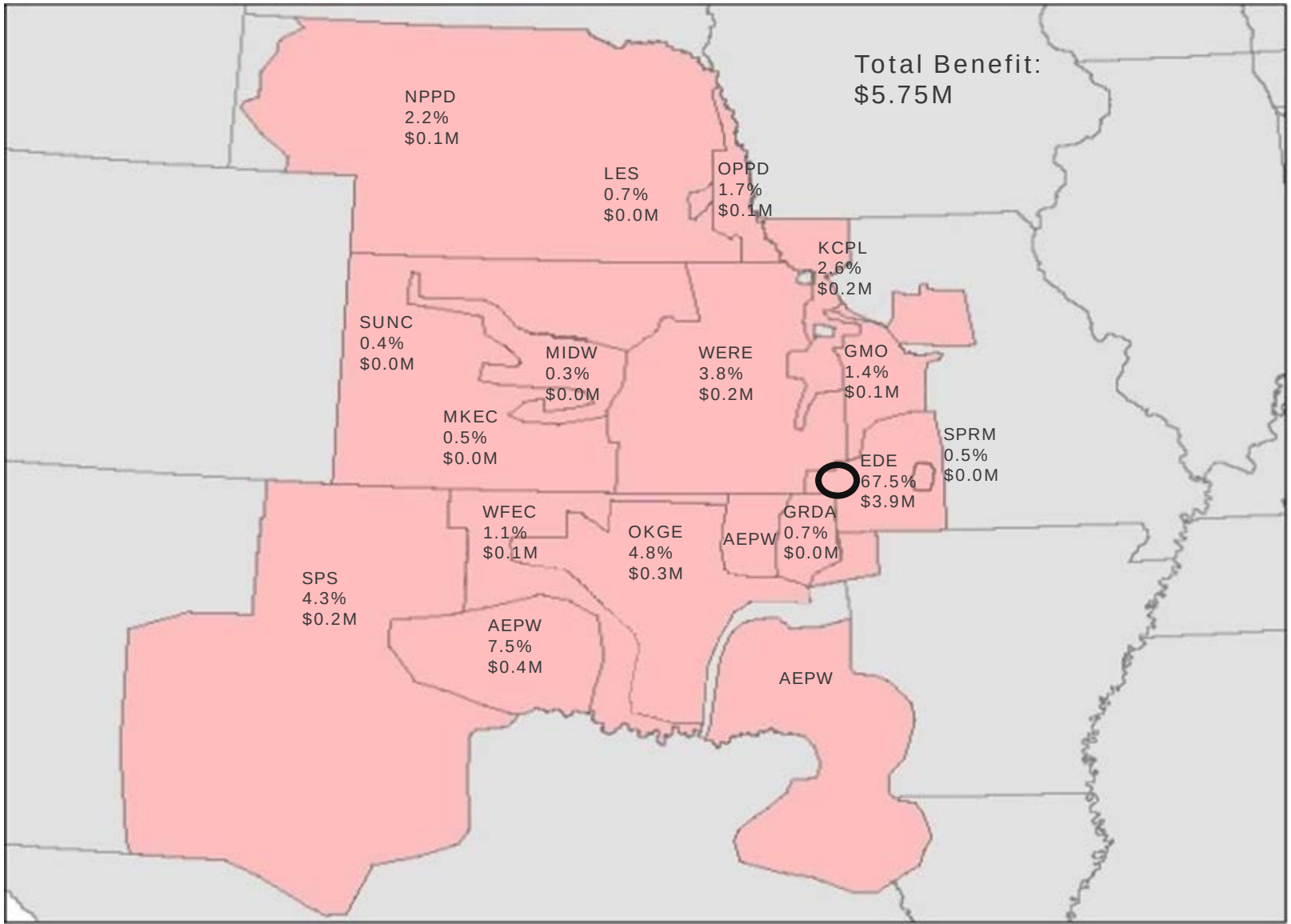
LODF – Riverton to Oronogo 161 kV



System Reconfiguration – Riverton to Oronogo 161 kV



Highway/Byway – Riverton to Oronogo 161 kV



Results Comparison – Elk City to Gracemont 345

Elk City - Gracemont 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$39,292,246	4.33%	$7,573,275	25.86%	$45,271,295	28.28%	$49,504,601
523	GRDA	2.01%	$3,523,360	4.63%	$8,101,643	0.18%	$317,298	0.25%	$440,642
524	OKGE	14.47%	$25,325,133	5.10%	$8,931,936	10.73%	$18,776,235	25.29%	$44,273,613
525	WFEC	3.27%	$5,723,806	2.03%	$3,547,614	31.82%	$55,702,459	18.25%	$31,957,451
526	SPS	12.98%	$22,725,093	49.74%	$87,075,536	23.39%	$40,938,371	21.08%	$36,909,220
531	MIDW	0.85%	$1,485,501	2.20%	$3,849,538	0.44%	$773,065	0.29%	$514,809
534	SUNC	1.08%	$1,893,089	0.89%	$1,559,944	1.82%	$3,185,503	1.33%	$2,329,731
536	WERE	11.48%	$20,100,127	3.39%	$5,937,850	2.44%	$4,273,778	2.71%	$4,751,080
540	GMO	4.18%	$7,318,366	3.66%	$6,415,897	0.14%	$239,365	0.21%	$362,112
541	KCPL	7.86%	$13,761,449	3.64%	$6,365,577	0.56%	$984,597	0.37%	$641,330
544	EMDE	2.53%	$4,430,995	4.35%	$7,623,596	0.08%	$144,036	0.21%	$375,200
546	SPRM	1.59%	$2,782,656	4.30%	$7,522,954	0.02%	$34,791	0.04%	$65,442
640	NPPD	6.69%	$11,706,991	3.08%	$5,384,322	1.81%	$3,171,586	1.03%	$1,801,833
645	OPPD	5.11%	$8,953,392	3.45%	$6,038,492	0.15%	$266,502	0.27%	$475,544
650	LES	2.03%	$3,555,862	3.33%	$5,837,209	0.07%	$126,641	0.16%	$274,856
539	MKEC	1.42%	$2,483,325	1.88%	$3,296,010	0.49%	$855,869	0.22%	$383,926
Total		100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392

Results Comparison – Summit to Elm Creek 345

Summit - Elm Creek 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$25,373,674	9.37%	$10,596,795	2.47%	$2,795,629	3.28%	$3,705,546
523	GRDA	2.01%	$2,275,273	9.85%	$11,137,448	0.18%	$201,992	0.48%	$537,902
524	OKGE	14.47%	$16,354,160	10.71%	$12,110,623	2.63%	$2,972,372	5.45%	$6,155,988
525	WFEC	3.27%	$3,696,250	11.00%	$12,435,015	0.74%	$840,232	0.66%	$747,086
526	SPS	12.98%	$14,675,137	11.38%	$12,867,537	2.38%	$2,693,230	0.48%	$537,902
531	MIDW	0.85%	$959,289	5.64%	$6,379,703	0.60%	$679,620	2.35%	$2,659,626
534	SUNC	1.08%	$1,222,496	5.88%	$6,650,030	8.41%	$9,507,664	6.95%	$7,859,344
536	WERE	11.48%	$12,980,018	8.61%	$9,731,751	61.01%	$68,973,344	56.89%	$64,309,154
540	GMO	4.18%	$4,725,966	4.07%	$4,595,549	0.49%	$555,479	1.24%	$1,404,521
541	KCPL	7.86%	$8,886,703	4.11%	$4,649,614	1.16%	$1,306,637	3.09%	$3,496,362
544	EMDE	2.53%	$2,861,394	8.51%	$9,623,620	0.05%	$61,720	0.29%	$328,718
546	SPRM	1.59%	$1,796,950	7.89%	$8,920,772	0.03%	$37,874	0.08%	$89,650
640	NPPD	6.69%	$7,560,000	1.24%	$1,405,697	1.82%	$2,054,991	3.97%	$4,482,515
645	OPPD	5.11%	$5,781,814	1.29%	$1,459,763	0.18%	$201,992	1.24%	$1,404,521
650	LES	2.03%	$2,296,261	0.24%	$270,326	0.18%	$209,006	0.74%	$836,736
539	MKEC	1.42%	$1,603,652	0.19%	$214,793	17.65%	$19,957,256	12.82%	$14,493,466
Total		100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038

Results Comparison – Riverton to Oronogo 161

Riverton - Oronogo Jct 161		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	7.48%	$430,193	1.33%	$76,192	16.15%	$928,694	6.35%	$365,101
523	GRDA	0.67%	$38,576	10.72%	$616,463	15.21%	$874,330	6.17%	$354,670
524	OKGE	4.82%	$277,273	2.05%	$117,751	3.86%	$222,066	1.36%	$78,009
525	WFEC	1.09%	$62,667	1.87%	$107,362	1.41%	$81,230	0.20%	$11,339
526	SPS	4.33%	$248,807	1.14%	$65,802	3.13%	$180,042	0.15%	$8,617
531	MIDW	0.28%	$16,264	1.09%	$62,653	0.22%	$12,799	0.02%	$907
534	SUNC	0.36%	$20,727	0.50%	$28,917	0.79%	$45,475	0.05%	$2,721
536	WERE	3.83%	$220,067	3.10%	$178,319	9.49%	$545,872	9.62%	$552,867
540	GMO	1.39%	$80,125	5.70%	$327,722	0.45%	$25,642	0.69%	$39,912
541	KCPL	2.62%	$150,668	5.36%	$308,444	1.36%	$78,281	2.39%	$137,423
544	EMDE	67.51%	$3,881,846	34.53%	$1,985,611	46.65%	$2,682,508	70.32%	$4,043,323
546	SPRM	0.53%	$30,466	20.12%	$1,156,667	0.13%	$7,623	2.41%	$138,784
640	NPPD	2.23%	$128,174	3.52%	$202,417	0.98%	$56,112	0.16%	$9,071
645	OPPD	1.70%	$98,027	4.19%	$240,972	0.11%	$6,334	0.04%	$2,268
650	LES	0.68%	$38,931	3.94%	$226,514	0.04%	$2,555	0.04%	$2,268
539	MKEC	0.47%	$27,189	0.84%	$48,194	0.01%	$437	0.05%	$2,721
Total		100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000

Comparison of Approaches

	DFAX	LODF	System Reconfiguration
Does it impact the total reliability benefit for a project?	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones
Does it measure how overloaded a line is or isn't?	No	No	No
Emphasizes use of the upgrade by…..	Zonal loads	Zonal branches	Zonal branches
Measures……	How much the upgrade is utilized in serving a zone's load	Additional flows that the upgrade will pick up when a zone's existing facilities are outaged	Additional flows that a zone's facilities will pick up when the upgrade is outaged
General allocation observation from examples	More levelized allocation than other methods	Significant benefit going to a few zones closest to upgrade	Significant benefit going to a few zones closest to upgrade
Complexity in evaluating numerous projects	Low to moderate	Moderate	Moderate
Other Notes	Based on powerflow dispatch, which might not be consistent with an economic model dispatch. Units are scaled up only if their existing dispatch in powerflow is less than max cap. Results can be dependent on where in the footprint the scaled generation is located.	Similar to the System Reconfiguration approach, but a reverse variation of it.	Similar to the LODF approach, but a reverse variation of it. This is the MW-mile approach without accounting for mileage.

PUBLIC POLICY BENEFITS

Public Policy Benefits – Previous Approach

- Benefits allocated to zones in proportion to each zone's share of unmet renewable energy goals.
  - Public Policy Benefit per zone = (% share of unmet goals) x (cost of upgrade)
  - If a zone has no public policy mandate or goal, or already meets their mandate or goal, their public policy benefit is zero
- Production cost savings due to policy upgrades are additional to this benefit

Potential Alternative for Benefit Allocation

- Public Policy Benefit is allocated only to zones in the state in which the mandate/goal is driving the project
- New Gentleman – Cherry – Holt 345 kV line
  - Driven by Nebraska goal
  - Benefits allocated to Nebraska entities
  - Total 40-Year Cost = Public Policy Benefit = $296.4 M

	Unmet Renewable Goal* (MWh)	% Share of Unmet Renewable Goal	Public Policy Benefit (millions $)
NPPD	1,374,534	48%	$143
OPPD	1,470,070	52%	$153
LES	0	0%	$0
Total	**2,844,604**	**100%**	**$296**

*These numbers represent unmet goals from the RCAR; these are not up-to-date with ITP10 data

State Policy Benefit Allocation – Example

	Unmet Renewable Goal (MWh)	% Share of **SPP** Unmet Renewable Goal	Public Policy Benefit - RCAR ($M)	% Share of **Nebraska** Unmet Renewable Goal	Public Policy Benefit - State Policy Allocation ($M)
AEPW	1,787,126	10.1%	$30	0.0%	$0
CUS	0	0.0%	$0	0.0%	$0
EDE	887,873	5.0%	$15	0.0%	$0
GMO	1,737,706	9.8%	$29	0.0%	$0
GRDA	0	0.0%	$0	0.0%	$0
KCPL	2,906,537	16.4%	$49	0.0%	$0
LES	0	0.0%	$0	0.0%	$0
MIDW	0	0.0%	$0	0.0%	$0
MKEC	228,122	1.3%	$4	0.0%	$0
NPPD	1,374,534	7.8%	$23	48.3%	$143
OKGE	3,485,957	19.7%	$58	0.0%	$0
OPPD	1,470,070	8.3%	$25	51.7%	$153
SUNC	126,037	0.7%	$2	0.0%	$0
SWPS	0	0.0%	$0	0.0%	$0
WEFA	804,394	4.6%	$13	0.0%	$0
WRI	2,868,358	16.2%	$48	0.0%	$0
Total	17,676,714	100.0%	$296	100.0%	$296

*If a policy project enables members in multiple states to meet their mandates/goals, the benefit would be applied to all impacted members

MITIGATION OF TRANSMISSION OUTAGES

Mitigation of Outage Costs – Existing Approach

- Add set of historical transmission outages to production cost simulations
- Benefit = APC Benefit$_{\text{With Outages}}$ – APC Benefit$_{\text{Without Outages}}$
  - This metric is an adder to traditional APC Benefit
- Since it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone, this benefit is calculated on an SPP-wide basis and allocated to zones based on a load ratio share.

APC Savings Allocation Approach

- For APC Savings with no outages, calculate each zone's benefit as a percentage of the total SPP benefit
- Multiply each zone's APC benefit % by the Mitigation of Transmission Outage Costs total benefit to determine that zone's allocation of the Total Outage benefit

APC Savings Allocation Approach

	Mitigation of Transmission Outages Benefit - RCAR, based on LRS ($M)	APC Savings - 40-year NPV benefit* ($M)	Percent of Total APC Savings	Mitigation of Transmission Outages Benefit - allocated by APC Savings % ($M)
AEPW	$76	$240	7.9%	$27
CUS	$5	$7	0.2%	$1
EDE	$9	$7	0.2%	$1
GMO	$14	$23	0.8%	$3
GRDA	$7	$10	0.3%	$1
KCPL	$27	$24	0.8%	$3
LES	$7	$5	0.2%	$1
MIDW	$3	$60	2.0%	$7
MKEC	$5	$42	1.4%	$5
NPPD	$23	$226	7.5%	$25
OKGE	$49	$175	5.8%	$20
OPPD	$17	$34	1.1%	$4
SUNC	$4	-$10	-0.3%	-$1
SWPS	$44	$1,939	64.2%	$218
WEFA	$11	$24	0.8%	$3
WRI	$39	$215	7.1%	$24
Total	$340	$3,021	100.0%	$340

Historical Outage Data Approach

- Obtained operational data for outages from Sept 2011 to present
  - Number of outages by zone
  - Operations used different application before Sept 2011, making it more difficult to query and organize data prior to Sept 2011
  - Some tie lines are being double counted (~5% of outages)
- Number of outages by zone was divided by total outages for region to obtain allocation factor by zone
- Allocation factor multiplied by total outages benefit

Historical Outage Data Approach

Zone	# of outages	Allocation %	Benefit based on outage data ($M)	Benefit based on LRS, from RCAR ($M)	Increase in Benefit with new methodology ($M)
AEP	3,044	21.64%	$74	$76	($2)
EDE	545	3.88%	$13	$9	$4
GRDA	273	1.94%	$7	$7	($0)
KCPL	431	3.06%	$10	$27	($17)
LES	212	1.51%	$5	$7	($2)
MIDW	123	0.87%	$3	$3	($0)
GMO	393	2.79%	$10	$14	($4)
NPPD	1,492	10.61%	$36	$23	$13
OKGE	2,326	16.54%	$56	$49	$7
OPPD	434	3.09%	$10	$17	($7)
SUNC/MKEC	602	4.28%	$15	$9	$6
CUS	218	1.55%	$5	$5	$0
SPS	2,238	15.91%	$54	$44	$10
WFEC	399	2.84%	$10	$11	($1)
WR	1,334	9.49%	$32	$39	($7)
Total	14,064	100.00%	$340	$340	$0

APPENDIX – METRICS REVIEW

DFAX Approach

For 10 MW transfer:

DFAX = (Post-transfer MW flow – Pre-transfer MW flow)/10 MW, in which:

- **Pre-transfer MW flow = MW flow over transmission upgrade before the 10 MW transfer**
- **Post-transfer MW flow = MW flow over transmission upgrade after the 10 MW transfer**

Wind units are excluded from the scaling

Units with GSF > 20% are excluded from the scaling

Transfers with positive DFAX are grouped together, and transfers with negative DFAX are grouped together

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Positive\ DFAX's}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right), if\ DFAX_{Zone\ A}\ is\ positive$$

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Negative\ DFAX's}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right), if\ DFAX_{Zone\ A}\ is\ negative$$

$$Reliability\ Project\ Benefit\ (\$)_{Zone\ A} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

LODF Approach

$$\sum LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}$$

Post contingent flow (MW) = MW flow on reliability upgrade after contingency

Pre contingent flow (MW) = MW flow on reliability upgrade prior to contingency

$$\boldsymbol{Allocation\ Factor_{Zone\ A}} = \frac{\sum LODF_{Zone\ A}}{\sum LODF_{All\ Zones}}$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)_{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

NOTE: Negative LODF's are excluded from this calculation. Only positive LODF's are summed in order to try to capture only the facilities in which the flows are being relieved by the upgrade.

System Reconfiguration Approach

$$\sum Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} +$$

$$\sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}$$

Post contingent flow (MW) = MW flow on system branch after reliability upgrade is outaged

Pre contingent flow (MW) = MW flow on system branch prior to reliability upgrade being outaged

$$\boldsymbol{Allocation\ Factor_{Zone\ A}} = \frac{\sum Relieved\ MW's_{Zone\ A}}{\sum Relieved\ MW's_{All\ Zones}}$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)_{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

NOTE: Only branches with <u>increased</u> flow after outage of reliability upgrade are included in calculation. Branches with decreased flow are zeroed out.

Economic Assessment Areas

April 3rd, 2014

SPP Southwest Power Pool

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

Background

- System congestion will be identified in each of the 8,784 hours.
- A list of binding constraints will be developed for each future and ranked based upon the average shadow price associated with each constraint.
- The top twenty constraints based upon this ranking will be identified as economic needs

Constraint List Options

- Top 20 constraints:
  - SPP Area only
  - SPP + Integrated System
  - SPP + Integrated System + Seams
- Top 20 constraints in the SPP area plus 5 top in the Integrated System
- Top 20 constraints in the SPP area plus 5 top in the Integrated System plus 5 top in the Seams

Recommendation

- **SPP Staff, recommends to use the top 20 constraints in the SPP area plus 5 top in the Integrated System plus 5 top in the Seams**

Policy Needs Assessment

ESWG

April 3rd, 2014

SPP Southwest Power Pool

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

Policy Needs Definition

- A policy need results when a company is unable to meet a renewable mandate/goal due to inadequate transmission to deliver wind
  - Results in wind curtailment in the SCUC/SCED simulation
- Transmission projects will be developed to address policy needs

Renewable Energy Standards by State

State	Type	Source	Amount
Arkansas	Court Order	United States District Court Order (SWEPCO)	400 MW in SWEPCO Service Territory (AR, LA, or TX)
Kansas	Statute	Kansas Statutes 66-1256 - 66-1262	10% - 2011 - 2015 15% - 2016 - 2019 20% - 2020
Louisiana	Court Order	United States District Court Order (SWEPCO)	400 MW in SWEPCO Service Territory (AR, LA, or TX)
Missouri	Statute	R.S. Mo. § 393.1020 et seq.	2% - 2011 - 2013 5% - 2014 - 2017 10% - 2018 - 2020 15% - 2021
Nebraska	State Agency	Public Power District Board Action	10% - 2020 (NPPD/OPPD)
New Mexico	Statute	Renewable Energy Act ("REA"), §§ 62-16-1 et seq. NMSA	10% - Current 15% - 2015 20% - 2020
Oklahoma	Statute	17 Okl. St. § 801.4	15% by 2015
Texas	Statute	TEX UT. CODE ANN. § 39.904 United States District Court Order (SWEPCO)	5,256 MW - Current 5,880 MW – 2015 400 MW in SWEPCO Service Territory (AR, LA, or TX)

Policy Needs Identification

- After SCUC/SCED simulation, renewable output will be analyzed by company, by state, to determine how much wind energy is being delivered vs. curtailed.
  - Wind from the OTHER category of Policy Survey does not qualify towards policy needs
  - Companies with annual wind energy output less than 97% of the scheduled energy output will be identified as having policy need(s)

Example 1

- Company A is subject to state renewable <u>capacity</u> mandate/goal of 150 MW
  - 150 MW (500,000 MWh) of installed wind driven by mandate/goal
    - Company must deliver 500,000 MWh * 0.97 = 485,000 MWh
  - 60 MW (200,000 MWh) of additional installed wind classified as OTHER
  - All 700,000 MWh of wind is available to meet required 485,000 MWh threshold

Example 2

- Company B is subject to renewable capacity mandate/goal of 55 MW in state X
  - 100 MW (400,000 MWh) of installed wind in state X assigned to company B
- Company B is subject to renewable energy mandate/goal of 1,000,000 MWh in state Y
  - 300 MW (1,000,000 MWh) of installed wind in state Y assigned to company B
- Company B must deliver (55 MW)*(CF)*(8,784 hrs)*(97%) to meet state X mandate/goal
- Any additional wind not needed to meet state X goal can be applied toward state Y goal

Next Steps

- Staff is working to assess specific requirements for each company, for each state, based on data from Policy Survey
- Analyze wind curtailments from model and identify companies that do not meet renewable mandates/goals

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 10th, 2014

AEP Offices, Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will use the Adding vs Combining methodology to calculate benefits from transmission upgrades and provide feedback to ESWG members.
2. ESWG Members will review the Tariff language to re-evaluate the ITP Process timeline.
3. ESWG members approved the March 13th meeting minutes.
4. ESWG members approved the March 24th meeting minutes.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 10th, 2014

AEP Offices, Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 9:33 a.m., welcomed those in attendance, and asked for introductions. (Attachment 1 – Attendance List)

There were 17 in person participants and 66 web conference participants representing 10 of 11 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP Staff) reviewed proxy statements. Three proxies were identified. Bruce Walkup (AECC) proxy to Michael Massery (AECC), Kurt Stradley (LES) proxy to Joe Lang (LES) and Al Tamimi (SUNC) proxy to Tom Hestermann (SUNC). (Attachment 2 – Proxies)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 3 – Agenda)

> **A motion to approve the agenda was made by Kurt Stradley (LES) and seconded by Paul Dietz (Westar). The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Juliano Freitas (SPP Staff) recapped the pending action item list and asked for additional updates or changes (Attachment 4 – Past Action Items). No changes or additional updates were provided.

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following items:

a. Approval of Meetings Minutes – March 13th, 2013 (Attachment 5 – 20140313 ESWG Minutes_Modified)

b. Approval of Meeting Minutes – March 24th , 2013 (Attachment 6 – 20140324 ESWG Minutes_Modified)

Tim Owens (NPPD) asked SPP Staff to change the language on both meeting minutes:

March 13, 2014 minutes.

Was:

Tim Owens (NPPD) had issues with the new Gentlemen-Cherry-Holt as a public policy project. When NPPD proposed this project, it relieved flow in Gentlemen. They never understood how this project turned into a public policy project, although it does help wind dispatch to Nebraska. There will need to be a determination as to whether it was the least cost solution to meet the renewable goal.

Change to:

Tim Owens (NPPD) questioned the new Gentlemen-Cherry-Holt line being categorized as a public policy project. When NPPD proposed this project, it was done so primarily to improve system stability by providing a parallel 345 kV path to the GGS stability limited flow gate. NPPD never understood how this project was categorized as a public policy project, although it does help wind dispatch in Nebraska. For purposes of calculating the Public Policy benefit for this project, there will need to be a determination as to whether it was the least cost solution to allow the renewable goals in Nebraska to be met, since that is an underlying assumption in setting the public policy benefit equal to the project cost.

March 24 minutes.

Was:

A motion to approve the proposed 2015 ITP10 Scope as is on March 24th, 2014 after changes was made by Tim Owens (NPPD) and seconded by Kurt Stradley (LES). The motion was approved unanimously.

Change to:

A motion to approve the proposed 2015 ITP10 Scope as presented on March 24th, 2014 and incorporating changes made by the ESWG during the meeting was made by Tim Owens (NPPD) and seconded by Kurt Stradley (LES). The motion was approved unanimously.

Chair Alan Myers (ITC Great Plains, LLC) asked if there were any Consent Agenda Items to be removed, changed, or added. The consent agenda was approved. Kip Fox (AEP-Transource) abstained from the vote.

Agenda Item 4 – Adding vs Combining Multiple Benefits

Mike Proctor (RSC Consultant) reviewed his previous presentation explaining the basic concept of the Adding versus Combining Multiple Benefits methodology. In his presentation the focus was in: classification when meeting multiple needs, avoided cost and importance of least cost. ESWG member asked SPP Staff to develop some examples using the method proposed by Mike in order to evaluate it. (Attachment 7 – Adding vs combing benefits from transmission upgrades)

ACTION ITEM: SPP Staff will use the Adding versus Combining methodology to calculate benefits from transmission upgrades and provide feedback to ESWG members.

Agenda Item 5 – 2015 ITP10 Schedule

Antoine Lucas (SPP Staff) presented the options to start the DPP window and the consequent impact on the schedule and remaining milestones, SPP Staff proposed three options: 1) Start the DPP window at May 9th and close it at June 8th; 2) Start the DPP window at May 16th and close it at June 15th and 3) Start the DPP window at May 23rd and close it at June 22nd. ESWG Members decided to keep the original date starting the process at May 9th. TWG also decided to keep the original date (Option 1). Some members expressed their concern about the lack of time to evaluate needs keeping the original date. (Attachment 8 – 2015 ITP10 Schedule)

> **A motion to adopt Option 1 for the 2015 ITP10 Study previously approved by the TWG was made by Tim Owens (NPPD) and seconded by Michael Watt (OMPA). The motion was approved. Kip Fox (AEP-Transource) abstained from this vote.**
>
> **A friendly amendment to slide the DPP window commensurate with any delay in the model posting date was made by Kip Fox (AEP-Transource) and seconded by Bennie Weeks (Xcel Energy). The motion was approved unanimously.**

ACTION ITEM: ESWG Members will review the Tariff language to re-evaluate the ITP Process timeline.

Agenda Item 6 – Metrics Review

This item was moved to the next ESWG Conference Call on April 24th 2014. (Attachment 9 – 2015 ITP10 Schedule)

Agenda Item 7 – 2014 Probabilistic Assessment Scope

Seth Mayfield (SPP Staff) presented the scope overview for the 2014 Probabilistic Assessment to the ESWG members. During this presentation Seth provided details about the process steps, data inputs and assumptions to be used during the study. The study will start on July 2014 and have a draft report by January 2015. This item was not an approval item, but ESWG members decided to go ahead and make a motion to approve the scope. (Attachment 10 – Probabilistic Assessment 2014 Scope Overview)

A motion to approve the 2014 Probabilistic Assessment Scope was made by Kip Fox (AEP-Transource) and seconded by Bennie Weeks (Xcel Energy). The motion was approved unanimously.

Agenda Item 8 – HPILS Update

Jay Caspary (SPP Staff) summarized the HPILS report and asked for ESWG Members approval. The conclusion of the study includes (Attachment 11 – HPILS Update):

- HPILS TF has completed its assignment per the approved scope and identified a cost effective solution set to address N-1 reliability needs through 2023
- Several HPILS Portfolio Projects need commitments prior to the next ITP study based on need dates and lead times, and criteria approved by HPILS TF and TWG
- HPILS does not bypass existing tariff processes, but compliments them per the BOD directive
- The suspended NTC-C for Tuco-Amoco-Hobbs is a reliability solution in 2020, but should be modified to Tuco-Yoakum-Hobbs to save significant costs and achieve better performance

A motion to approve the HPILS Report was made by Al Tamimi (SUNC) and seconded by Bennie Weeks (Xcel Energy). The motion was approved.

Randy Collier (CUS) voted no for the following reason: City Utilities does not support approval of the HPILS Report at this time. Our reasons are as follows:

- There was inadequate time to review the final report prior to the approval vote. The HPILS Task Force did not approve the final report until April 2, 2014.
- City Utilities has numerous questions and concerns about findings and results incorporated into the final report. An example of our concerns follows:
    - On slide 25 of the HPILS PowerPoint presentation (40 Year NPV Value of THY based on APC), City Utilities' benefit is listed as $17.6 million for the Tuco-Yocum-Hobbs project (which is located in west Texas and eastern New Mexico). City Utilities' zonal benefit listed for this project ranks second among all SPP zones, behind only SWPS (the host zone for the project). Benefits listed for neighboring zones are considerably less than City Utilities, which causes concern not only for this project's benefit allocation, but also for the other projects included in the HPILS report.

~~• There was inadequate time to review the final report prior to the approval vote. The HPILS Task Force did not approve the final report until April 2, 2014.~~

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- ~~City Utilities has numerous questions and concerns about findings and results incorporated into the final report. An example of our concerns follows:~~
  - ~~On slide 25 of the HPILS PowerPoint presentation (40 Year NPV Value of THY based on APC), City Utilities' benefit is listed as $17.6 million for the Tuco-Yocum-Hobbs project (which is located in west Texas and eastern New Mexico). City Utilities' zonal benefit listed for this project ranks second among all SPP zones, behind only SWPS (the host zone for the project). Benefits listed for neighboring zones are considerably less than City Utilities, which causes concern not only for this project's benefit allocation, but also for the other projects included in the HPILS report.~~

Kip Fox (AEP-Transource) abstained from this vote.

Agenda Item 9 – DPP Project Selection Methodology

Juliano Freitas (SPP Staff) delivered the presentation to discuss the criteria to select economic projects in Phase 1 of the DPP evaluation. ESWG Members decided to move this item to the next Conference Call on April 24th 2014 for further discussion. (Attachment 12 – DPP Project Selection Methodology)

Agenda Item 10 – Economic Assessment Areas

Juliano Freitas (SPP Staff) presented a recommendation from SPP Staff on how to select the number of economic needs including the SPP region,the Integrated System, and also the Seams areas. Originally the proposal was to include the top 20 constraints in the SPP area, in order to increase the possibility of having more projects due to economic reasons. SPP Staff recommended up to the top 20 constraints in the SPP area, plus up to the 2 top in the Integrated System plus up to the 8 top along the Seams. Members asked SPP Staff to re-evaluate the number of needs proposed with the cut off number based on congestion severity. The ESWG suggested that Staff should make the decision on the number of Economic Needs to be evaluated, but provide a justification for the rationale to the ESWG. SPP Staff will propose a threshold for congestion cost and bring it back to the ESWG members for their evaluation. (Attachment 13 – Economic Assessment Areas)

Agenda Item 11 – SPP – Policy Assessment Needs

Kelsey Allen (SPP Staff) presented a methodology to select policy needs in the current 2015 ITP10 Study. In the proposed methodology, wind from the Other category of the Policy Survey does not qualify towards policy needs. Also, the needs will not be determined based on individual wind farms, it will be a combination of all wind farms allocated to a utility to meet the requirements in the state driving the mandate or goal. ESWG members decided to make a motion to approve the methodology proposed by SPP Staff. . (Attachment 14 – Policy Assessment Needs)

A motion to approve the staff proposed methodology with additional consideration for individual state by state requirements was made by Kip Fox (AEP-Transource) and seconded by Randy Collier (CUS). The motion was approved unanimously.

Agenda Item 15 – Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 3:40 p.m.

Respectfully Submitted,

Juliano Freitas

ESWG Secretary

SPP Southwest Power Pool

Name	Email	Attendance
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Alan Myers		In Person
Alex Watkins SPP	awatkins@spp.org	Webex
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Anita	asharma@aep.com	Webex
Antoine Lucas		In Person
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Bary Warren		In Person
Ben Roubique		In Person
Bennie Weeks		In Person
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Blaine Erhardt	berhardt@bepc.com	Webex
Brad Schwarz		In Person
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Jody Holland		In Person
Joe Lang		In Person
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Keith Tynes	keithtynes@sbcglobal.net	Webex
Kelsey Allen		In Person
Kip Fox		In Person
Kirk Hall	khall@spp.org	Webex
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Seth Mayfield	smayfield@spp.org	Webex
Shaun Scott	smscott@spp.org	Webex
Shawnee Clairborn-Pinto		In Person
Thanh Tran (BMcD)	tntran@burnsmcd.com	Webex
Tim Owens		In Person
Tim Soles		In Person
Tom DeBaun (KCC)	t.debaun@kcc.ks.gov	Webex
Tom Hestermann	tkhestermann@sunflower.net	Webex
Wayman Smith (AEP)	wlsmith1@aep.com	Webex

ECONOMIC STUDIES WORKING GROUP

April 10th, 2014

AEP Offices, Dallas, TX

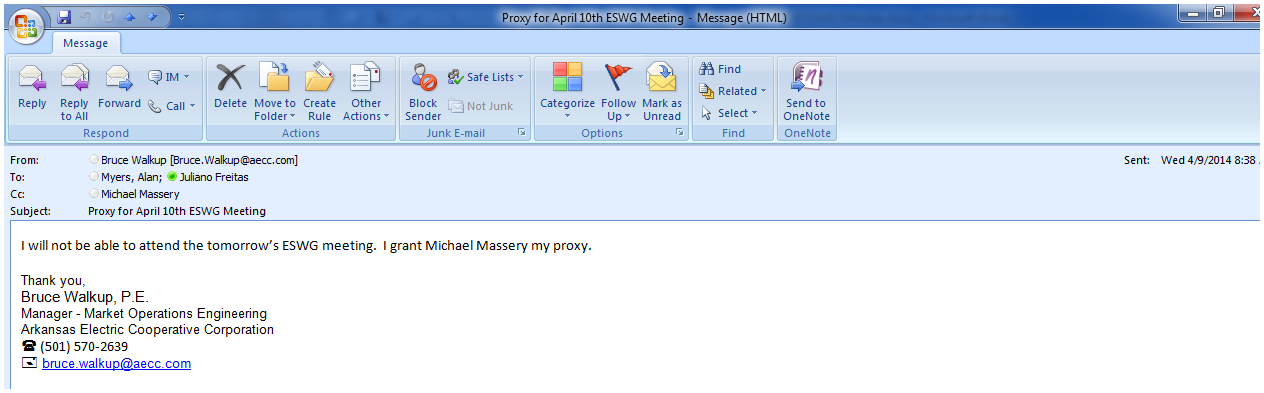
• A G E N D A •

9:30 pm – 3:30 pm

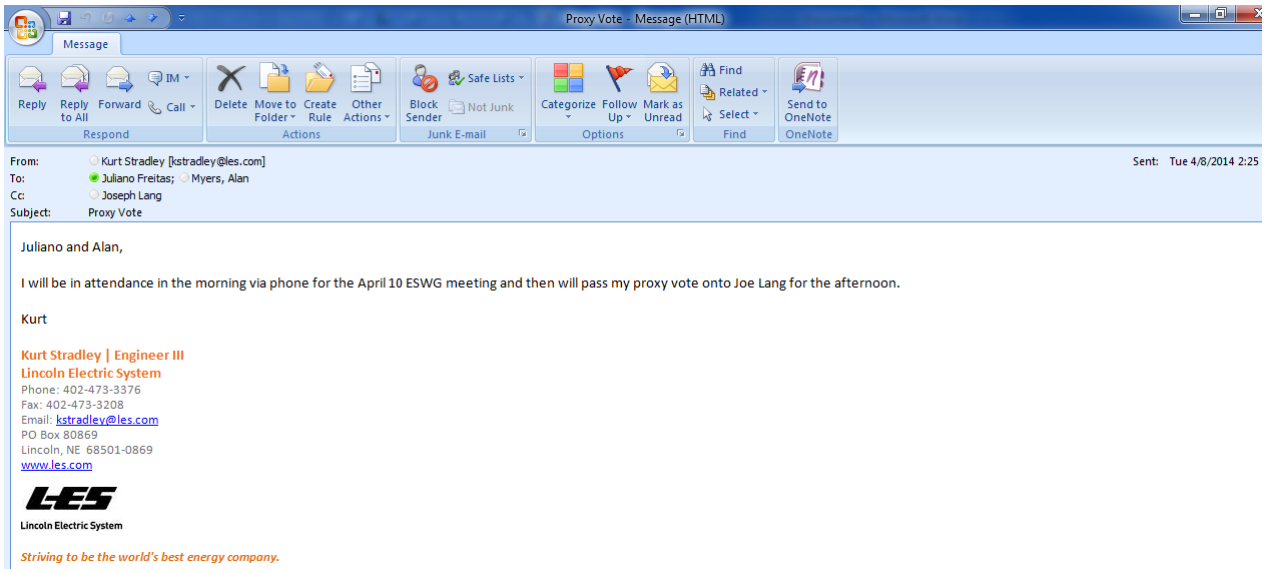
1. Administrative items
    a. Call to Order, Introductions ..... Alan Myers (5 minutes)
    b. Receipt of Proxies ..... Juliano Freitas (1 minute)
    c. Review of Agenda ..... Alan Myers (1 minute)
2. Review of Past Action Items ..... Juliano Freitas (10 minutes)
3. Consent Agenda (Approval Item)[i] ..... Alan Myers (10 minutes)
    a. Approval of Meetings Minutes – March 13th, 2014
    b. Approval of Meeting Minutes – March 24th, 2014
4. Adding vs Combining Multiple Benefits ..... Mike Proctor (1 hour)
5. 2015 ITP10 Schedule ..... Antoine Lucas (15 minutes)
6. Metrics Review ..... SPP Staff (1.5 hour)
7. 2014 Probabilistic Assessment Scope ..... Seth Mayfield (1 Hour)
8. HPILS Update (Approval Item) ..... Jay Caspary (30 minutes)
9. DPP Project Selection Methodology ..... Juliano Freitas (30 minutes)
10. Economic Assessment Areas ..... Juliano Freitas (10 minutes)
11. Policy Assessment Criteria ..... Kelsey Allen (30 minutes)
12. Closing Items ..... All

[i] Background Materials Included

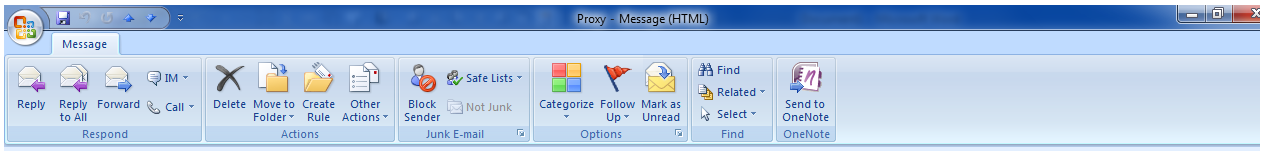
Bruce Walkup (AECC) to Michael Massery (AECC).



Kurt Stradley (LES) to Joe Lang (LES).



At Tamimi (SUNC) to Tom Hestermann (SUNC).



From: Tamimi, Al [atamimi@sunflower.net]
To: Myers, Alan
Cc: Juliano Freitas
Subject: Proxy
Sent: Thu 4/10/2014 9:38 A

Tom Hestermann has my Proxy from 10 am – 11:30 am. I will be at a Doctor appointment.

Al Tamimi, Ph.D., P.E.
Sunflower Electric Power Corporation
P.O. Box 1020 - Hays, KS 67601
HYS Office: 785-623-3336
GB Office: 620-793-1248
Cell: 785-656-0435
Email: atamimi@sunflower.net
Sunflower Electric Power Corporation

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

April 10th, 2014

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 2013.	Aug 23, 2012 ESWG	In Progress Staff	Staff will provide a draft report in November 2014. Staff recommends a discussion during the ESWG meetings in the previous months.
076	ESWG will analyze the aggregate studies impact on the 2015 ITP10 study for transmission service request	May 16, 2013	In Progress ESWG Members	Item on hold, wait for Aggregate Studies new results
082	SPP Staff will review the hurdle rates between SPP and 1st tier RTOs using MISO data	July 11, 2013	Complete	Staff will review hurdle rates during the benchmarking process scheduled for January 2014 completion.
083	SPP Staff will propose a methodology to model Must Run units in the 2015 ITP10 Study (Must Run units – Economic Aspect)	July 11, 2013	Complete	Needed by 1st quarter 2014.
087	ESWG members and SPP Staff will compare the generation resources in the different models used in the SPP studies processes	August 13' 2013	In Progress	
101	ESWG to provide wording for Solutions recommendation of the Scope by April 2014 MOPC	October 15-16, 2013 MOPC	In progress	
102	ESWG/TWG finalize the benefits metrics & allocation methods for 2015 ITP10 Portfolio analysis and bring back to April 2014 MOPC	October 15-16, 2013 MOPC	In progress	
104	ESWG members will provide feedback regarding the 2010 Strategic Plan by March 2014	November 21, 2013	In progress	
105	SPP Staff will investigate developing a regular process for economic model development and review.	December 19, 2013	In progress	

106	SPP Staff will provide the proof of concept analysis completed to support the new interconnection local/regional impacts proposal to stakeholders for informational purposes.	December 19, 2013	Complete	
107	SPP Staff will develop a detailed draft of the transmission project selection process in the ITP for inclusion in the scope.	December 19, 2013	In progress	
108	SPP Staff will draft “extraordinary circumstances” language for inclusion of projects in the project selection process that do not meet portfolio consolidation criteria.	December 19, 2013	In progress	
110	SPP Staff will review unused metrics developed by the Metrics Task Force (MTF) and bring back background information to the group.	December 19, 2013	In progress	
111	SPP Staff will provide calculation examples to aid in metrics review.	December 19, 2013	In progress	
112	SPP Staff will compile the information created during the Strategic Plan discussion and present to the group on the next ESWG face to face meeting on March 13th.	February 13, 2014	Complete	
113	SPP Staff will run DFAX not scaling units with generation shift factor greater than 20%, not scale wind units and will include positive and negative DFAX in the analysis	February 19, 2014	Complete	
114	SPP Staff will add the Highway/Byway methodology on the Slide number 24, Metrics Review presentation.	March 13, 2014	In progress	
115	SPP Staff will send the additional metrics list to members showing the ones Staff can calculate.	March 13, 2014	Complete	
116	SPP Staff will provide the RCAR schedule	March 13, 2014	In progress	
117	SPP Staff will use the Adding vs Combining methodology to calculate benefits from transmission upgrades and provide feedback to ESWG members.	April 10, 2014	In progress	
118	ESWG Members will review the Tariff language to re-evaluate the ITP Process timeline	April 10, 2014	In progress	

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 13th, 2014

AEP Offices, Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will detail the changes in the 2015 ITP10 Economic Model.
2. ESWG members approved the February 13th meeting minutes.
3. ESWG members approved the February 19th meeting minutes.
4. SPP Staff will review the action item number 102 language.
5. SPP Staff will add the Highway/Byway methodology on the Slide number 24, Metrics Review presentation.
6. SPP Staff will provide the RCAR schedule.
7. SPP Staff will send the additional metrics list to members showing the ones Staff can calculate.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 13th, 2014

AEP Offices, Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 9:30 a.m., welcomed those in attendance, and asked for introductions. (Attachment 1 – Attendance List)

There were 20 in person participants and 57 web conference participants representing 10 of 11 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP Staff) reviewed proxy statements. No proxies were identified.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 2 – Agenda)

> **A motion to approve the agenda as amended was made by Tim Owens (NPPD) and seconded by Kip Fox (Transource/AEP). Items 9 and 10 changed in the presentation order. The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Juliano Freitas (SPP Staff) recapped the pending action item list and asked for additional updates or changes (Attachment 3 – Past Action Items).

ACTION ITEM: SPP Staff will review the action item number 102 language.

Agenda Item 3 – Consent Agenda

The Consent Agenda included the following items:

a. Approval of Meetings Minutes – February 13th, 2013 (Attachment 4 – ESWG 2.13.14 Minutes & Attachments)

b. Approval of Meeting Minutes – February 19th , 2013 (Attachment 5 – ESWG 2.19.14 Minutes & Attachments)

Chair Alan Myers (ITC Great Plains, LLC) asked if there were any Consent Agenda Items to be removed, changed, or added. The consent agenda was approved unanimously.

ACTION ITEM: SPP Staff will detail changes in the economic model.

Agenda Item 4 – HPILSTF Report Update

Jay Caspary (SPP Staff) updated ESWG members about the HPILS Report. The Task Force is working on SCERTS, NTCs, graphics, and maps so folks understand where projects are and how we got them.

Task Force is also requesting withdrawal of two of the three reevaluated NTC-Cs (Tuco-New Deal 345kV and Grassland-Wolfforth 230kV) and recommending adjusting the Tuco-Amoco-Hobbs (TAH) NTC to a Tuco-Yoakum-Hobbs (TYH) as a solution. TYH proves to be a better project (lower cost and reliable) to TAH. As for projects with a 2023 need date, TAH has a 2023 need dates. The TY piece of TYH has a need date of 2023. 2016, 2017, 2018 are the major need dates

HPILSTF will have a WebEx next week and draft report has been posted. ESWG will have to review the economic portion once it has been approved by the HPILSTF. There shouldn't be a lot for ESWG to discuss.

Agenda Item 5 – Metrics Review

Antoine Lucas (SPP Staff) continued the discussion of metrics that have been developed previously.The focus of his presentation was on the calculation and allocation of benefits associated with metrics that have received more attention from stakeholders during ITP and the previous RCAR. On this presentation, the focus was on benefit allocation regarding three metrics: assumed benefit of mandated reliability projects, public policy benefits and mitigation of transmission outage costs. For the assumed benefit of mandated reliability projects, four methodologies were presented: Highway/Byway, DFAX, LODF and System Reconfiguration. For Public Policy, Antoine presented the current methodology and the State Policy Benefit Allocation methodology. The last metric approached was the mitigation of transmission outage costs and Antoine explained three possible methodologies to be used, the current methodology, the APC savings allocation and the historical outage data approach. (Attachment 6 – Metrics Review)

ACTION ITEM: SPP Staff will add a slide on the presentation to explain the Highway/Byway methodology.

ACTION ITEM: SPP Staff will provide the RCAR 2 schedule.

The main comments about the mandated reliability projects were:

- Implementing the DFAX allocation methodology, SPP Staff explained only generators committed with head room can participate in the transfer simulation. Any generator with GSF ≥ 20% was excluded from calculation. ESWG members mentioned that results do not appear practical, as benefit allocation is too evenly dispersed throughout the system given the location of projects. Staff responded that results seem consistent with the Highway/Byway approach. Members expressed concern with biased results because of P_{Gen} reserve margin scaling, rather than P_{Max} scaling. The membership also suggested using directional magnitude in addition to the directional flows. PJM utilizes a normalized DFAX calculation.
- There were no comments on the LODF approach.
- SPP Staff explained that the System Reconfiguration approach is a modification of MW/mile approach. This methodology would be the opposite of the LODF approach. This process takes the reliability project out of service and monitors in-service lines in the system; every branch is then analyzed. Membership stated that the LODF and System Reconfiguration approaches mirror each other, so expect to have results/percentages that are similar.

Some members expressed concern in these areas:

- How do each of these methodologies compares when it comes to man hours? DFAX is simpler once MON and CON files are set. The other methods are longer because you're doing a full N-1 contingency.
- The accuracy of DFAX is compromised due to benefit flowing across seams.
- Resources are based on IRP state requirements (not SPP), thus the DFAX approach is not applicable.
- NPPD feels there is not enough knowledge about alternatives to make a decision right now.
- KCPL is supportive of anything that goes away from current Highway/Byway as an allocation methodology.

- Xcel Energy cannot support approaches that allocate benefits differently than how costs are allocated.

A straw poll was suggested to identify the members tendency about this metric, the options were:
1) Status Quo - include the metric and Highway/Byway allocation methodology,
2) Include the metric and give the ESWG more time to evaluate the proposed methodologies, and
3) Not include the metric in the 2015 ITP10 Study.

The result of the straw poll was: 6 votes for option 1, 2 votes for option 2 and 1 vote for option 3. Non-ESWG members also registered their votes: EMDE and OPPD voted for option 3, Steve Gaw (Wind Coalition) voted in favor of option 1, and Wayman Smith (AEP) preferred option 2.

A motion to adopt the option 1 (Status Quo) and improve it as soon as possible was made by Paul Dietz (Westar) and seconded by Bennie Weeks (Xcel Energy). The motion was approved, 5 votes in favor and 4 votes against. The justifications for voting NO are in the paragraphs below.

Kip Fox (Transource/AEP) - The purpose of this email is to explain the AEP No vote to the ESWG motion "keep the reliability benefit calculation used in the RCAR as part of the 2015 ITP benefit calculation metrics (benefits are equal to cost and benefit allocated on a highway/byway cost allocation basis) with the ESWG continuing to evaluate other alternative calculation methods. Our rationale for the NO vote is as follows:

1. Any decision is premature until thoroughly vetted: The information on the various ways to calculate reliability (DFAX, Line Outage Distribution Factor, System Reconfiguration) were only reviewed in today's meeting with several issues (use of PMAX, volumetric issues, Shift Factor impacts) still to be resolved. There was not a clear understanding of the members on how the three methods would be calculated in the ITP 10 for 2015. The materials have only been evaluated for a week and this is a highly complex issue that other RTO's have struggled with for years. To include the current reliability benefit not only does ESWG a disservice but we have neglected our obligation to MOPC to research, discuss and recommend an innovative solution to default to the status quo. The reliability calculation is a post processing calculation and is NOT used to determine the need for a reliability upgrade. The reliability benefit calculation will not need to be addressed until SPP staff needs to begin the benefit calculations in September. This allows ESWG to have more time to evaluate the proposals presented today.

2. The presented options addressed reliability benefits better than the current methodology: The ESWG was in majority agreement that the alternatives discussed offered more precise reliability benefits but most members wanted more discussion on the technical merits. The group took a straw poll which was very close. AEP had no idea this straw poll would lead to a motion to approve. AEP is still reviewing the merits of the alternatives now that we have a better understanding of the proposals and that the proposals offer better reliability allocation than the current highway/byway methodology.

Randy Collier (City Utilities of Springfield) - City Utilities votes no on the motion to make no changes to the 2015 ITP10 (relating to inclusion of mandated reliability project metrics). City Utilities believes this metric should be included in order for the 2015 ITP10 metrics to be consistent with the metrics used in the RCAR II process.

Tim Owens (NPPD) - The purpose of the email to explain the NPPD no vote on the ESWG motion "to include the Assumed Benefit of Mandated Reliability Projects metric in the 2015 ITP10, with the ESWG continuing to evaluate other alternative allocation methodologies." Several alternative methods for allocating the benefit of mandated reliability projects to individual zones have been proposed. Example results presented to the ESWG to date do not seem intuitive and continue to change as adjustments are made to the underlying calculations. Based on these example results, there does not appear to be a consensus amongst the ESWG members as to which of the alternatives, if any, represent a clear improvement over the current allocation based on load ratio share. Until the ESWG is able to reach consensus on a complete recommendation regarding both

the calculation of the benefit and the associated benefit allocation, we do not believe it is appropriate to include this benefit metric in the 2015 ITP10.

For Public Policy Benefits the main comments from members were related to the potential alternatives for benefit allocation. Membership clarified that this benefit is allocated only to zones in the state in which the mandate/goal is driving the project. Mike Proctor mentioned that Priority Projects make a large component of the costs that go into RCAR. During Priority Projects, there was no public policy analysis done; everything was based strictly on APC savings. These projects are driving a lot of projects into SPP. This proposed metric would make it difficult to determine which unmet goals were driving these projects. There was much concern about how to apply this. The SPP proposal focuses on how wind is transported into SPP. Wind doesn't serve only the load in the state it's located.

Tim Owens (NPPD) questioned the new Gentlemen-Cherry-Holt line being categorized as a public policy project. When NPPD proposed this project, it was done so primarily to improve system stability by providing a parallel 345 kV path to the GGS stability limited flow gate. NPPD never understood how this project was categorized as a public policy project, although it does help wind dispatch in Nebraska. For purposes of calculating the Public Policy benefit for this project, there will need to be a determination as to whether it was the least cost solution to allow the renewable goals in Nebraska to be met, since that is an underlying assumption in setting the public policy benefit equal to the project cost.

~~Tim Owens (NPPD) had issues with the new Gentlemen-Cherry-Holt as a public policy project. When NPPD proposed this project, it relieved flow in Gentlemen. They never understood how this project turned into a public policy project, although it does help wind dispatch to Nebraska. There will need to be a determination as to whether it was the least cost solution to meet the renewable goal.~~

A straw poll was suggested to identify the members tendency about this metric, the options were:

1) Status Quo,
2) Include the metric but further discussion on project classification is needed,
3) Adopt the new proposed methodology, and
4) Not include the metric until the group has a better definition.

Option 2 got 6 votes and option 4 got 2 votes. Option 2 won the straw poll.

Kip Fox (Transource/AEP) made a motion to adopt the option 2 for the 2015 ITP10, but nobody seconded the motion. Motion dismissed.

For the Mitigation of Outage Costs metric, a straw poll was suggested to identify the members' preferences, the options were:

1) Status Quo (no methodology decided, since this metric was not in the previous ITP10),
2) Include the metric but give ESWG additional time for further discussion,
3) Adopt the new proposed methodology:
   a) APC Savings Allocation approach, or
   b) Historical Outage approach, and
4) Not include the metric until the group has a better definition.

The option 2 got 5 votes and option 3a got 3 votes. Option 2 won the straw poll.

A motion to adopt option 2 was made by Tim Owens (NPPD) and seconded by Kurt Stradley (LES). The motion was approved unanimously.

In the last part of this presentation, Antoine talked about five metrics not used before in the ITP process, Increased Wheeling Through and Out Revenues, Capital Savings Due to Reduction of Members' Minimum Required Margin, Reducing the Cost of Extreme Events, Reduced Loss of Load Probability, and Marginal Energy Losses Benefits. According to SPP Staff, considering labor intensive and time limitations, only two metrics are feasible: Increased Wheeling Through and Out Revenues and Marginal Energy Losses (Attachment 7 – Additional Metrics).

ACTION ITEM: SPP Staff will send additional metrics list to ESWG members showing the ones SPP Staff can calculate.

Agenda Item 6 – 2015 ITP10 Schedule

Antoine Lucas (SPP Staff) updated the ESWG members regarding the 2015 ITP10 Schedule. Staff has started working on DC to AC conversion to help with delays from the Constraint Assessment. Antoine also explained the risks in the schedule:

- Recommended HPILS projects are not yet approved. As a result, a lot of rework including the Constraint Assessment could be required if these projects are not approved in April. This would place the opening of the May 2 DPP window at risk.
- A delay in the TWG approval of the EVE file posted earlier in the week could delay the schedule.

Members asked about generation outlet facilities from the HPILS Resource Plan being included in the model. Staff responded that they are currently not in the model. (Attachment 8 – 2015 ITP10 Schedule)

Agenda Item 7 – 2010 Strategic Plan

Juliano Freitas (SPP Staff) requested member feedback by March 21st COB. (Attachment 9– 2010 Strategic Plan)

Agenda Item 8 – Constraint Assessment

Kirk Hall (SPP Staff) gave ESWG members a brief update due to time constraints. TWG had input and questions for the EVE file, so the vote has been pushed back from Monday, March 17th to Wednesday, March 19th. (Attachment 10 – 2015 ITP10 Constraint Assessment).

Agenda Item 9 – DPP Project Selection Methodology

This item was moved to the March 24th Conference Call. (Attachment 11 – DPP Project Selection Methodology)

Agenda Item 10 – BPR 050

Brett Hooton (SPP Staff) gave ESWG members a brief recap of his last presentation on BPR 050 at the February 13th ESWG meeting. (Attachment 12 – BPR 050)

A motion to approve the BPR 050 as modified was made by Tim Owens (NPPD) and seconded by Kip Fox (Transource/AEP). The motion was approved.

Agenda Item 11 – SPP – MISO Coordinated System Plan

Brett Hooton (SPP Staff) advised ESWG members that the team for the SPP-MISO study is working on the scope development. As it is now, the scope indicates a business as usual future with 2 sensitivities: high carbon tax and high gas price. The study will also have a 10-year planning scope. MISO has requested changing the study deadline to June 2015. (Attachment 13 – SPP – MISO Coordinated System Plan)

Agenda Item 12 – Probabilistic Assessment Scope

This item was moved to the April 10th ESWG meeting's agenda. (Attachment 14 – Probabilistic Assessment 2014 Scope Overview)

Agenda Item 15 – Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 3:37 p.m.

Respectfully Submitted,

Juliano Freitas

ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 24th, 2014

Web Conference

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will provide more details about the methodology to identify local issues caused by new generation.
2. SPP Staff will contact PJM to exchange knowledge about the DFAX methodology.
3. Run DFAX not scaling units with generation shift factor greater than 20%.
4. SPP Staff will include positive and negative DFAX in the analysis.
5. ESWG members will provide feedback regarding must-run on February 20th 4 PM.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 24th, 2014

Web Conference

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 1:04 p.m., welcomed those in attendance. (Attachment 1 – Attendance List)

There were 33 web conference participants representing 10 of 11 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP staff) requested proxy statements. One proxy was identified, Kip Fox (AEP-Transource) proxy to Wayman Smith (AEP). (Attachment 2 – Proxies)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 3 – Agenda)

> **A motion to approve the proposed agenda was made by Tim Owens (NPPD) and seconded by Wayman Smith (AEP). The motion was approved unanimously.**

Agenda Item 2 – DPP – Projects Selection Methodology

Juliano Freitas (SPP staff) presented the methodology developed by SPP Staff to select economic and policy projects to be included in the final 2015 ITP10 portfolio. The process consists of three phases; the intention is to select the optimal projects in order to have a robust transmission plan. In phase one, projects will be evaluated on an individual basis, with the selection being made considering the economic and/or policy performance of each project. In phase two, the projects performance will be measured as part of a grouped portfolio, evaluating first the reliability projects, and then on top of that policy projects, and finally the last group to be added will be the economic projects. Phase three consists of a consolidation methodology combining the final groupings from both futures. The DPP project submittal window will begin after assessments are complete. (Attachment 4 – DPP – Projects Selection Methodology)

Agenda Item 3 – 2015 ITP10 Consolidation Methodology

Kelsey Allen (SPP Staff) presented the consolidation methodology; the ESWG members approved the economic and policy project consolidation approach in December 2013. The final approval was pending because the TWG did not have a final position regarding the reliability approach at that time. The ESWG members decided to approve the language without further questions. (Attachment 5 – Consolidation Methodology)

> **A motion to approve the proposed consolidation methodology language was made by Wayman Smith (AEP) and seconded by Kurt Stradley (LES). The motion was approved unanimously.**

Agenda Item 4 – ESWG Survey

Juliano Freitas (SPP Staff) presented the results of the 2013 ESWG Survey. The two main points discussed were: 1) Meeting materials are provided in a timely manner; 2) Members come prepared to meetings. The overall satisfaction was 4.1 out of 5 points possible. SPP Staff is proposing to re-evaluate the ESWG actions every 3 months in order to improve the group's dynamic. (Attachment 6 – ESWG Survey). The member's feedback regarding the subject is described below:

Tim Owens (NPPD): Here is a summary of my verbal comments this afternoon on the ESWG survey topic.

- I would concur with Juliano's suggestion that periodically throughout the year the ESWG review the items from the last survey to gage our progress and see if additional adjustment to our processes are appropriate.
- Consider a shorter lead time (than our current target of 7 days before the meeting) for posting materials that are informational in nature, to allow for the most current information to be included. For agenda items where approval is being requested, keep the current 7 day target for posting materials and minimize additional changes to the materials after that initial posting if at all possible.
- For agenda items where approval is being requested, encourage ESWG members to ask clarifying questions or request additional information of staff prior to the meeting, rather than waiting until the meeting. Hopefully this would help members to come to the meeting better prepared to take action on those approval items.

Agenda Item 5 – 2015 ITP10 Scope

Juliano Freitas (SPP Staff) presented the changes to the 2015 ITP10 Scope. The main changes since January 2014 were the consolidation methodology and sensitivity analysis language. The intention is to get the MOPC and BOD approvals in April 2014. (Attachment 7 – 2015 ITP10 Scope - Redline)
Members suggested changes to the original proposal for consolidation methodology; the final approved language was:
"The final portfolio for each future will be consolidated into a single portfolio. The consolidation will be based on the following criteria: Economic projects with a 1-year B/C ratio greater than 0.9 in Future 1 will be included in the consolidated portfolio. Economic projects with a 1-year B/C ratio greater than 0.7 in Future 1, but that also have a 1-year B/C ratio greater than 0.9 in Future 2 will also be included in the consolidated portfolio.

Policy projects will be included in the consolidated portfolio if they meet a policy need in Future 1.

Reliability projects will be included in the consolidated portfolio if they mitigate a thermal/voltage violation in Future 1. A Future 2 reliability project will be included if it mitigates a thermal violation in Future 2 and mitigates loading above a 90% threshold in Future 1. A Future 2 project that mitigates a voltage limit violation in Future 2 and voltage below 0.92 pu in Future 1 will also be included in the consolidated portfolio. Thermal and voltage violations are defined by SPP Criteria and local Transmission Owner criteria.

Additionally, projects with significant potential value may be selected to be part of the consolidated portfolio. SPP Staff can request additional projects be included in the consolidated portfolio, but they will be required to present the project and justification to the appropriate stakeholder groups and obtain approval from those groups."

~~**A motion to approve the proposed 2015 ITP10 Scope as is on March 24th, 2014 after changes was made by Tim Owens (NPPD) and seconded by Kurt Stradley (LES). The motion was approved unanimously.**~~ **A motion to approve the proposed 2015 ITP10 Scope as presented on March 24th, 2014 and incorporating changes made by the ESWG during the meeting was made by Tim Owens (NPPD) and seconded by Kurt Stradley (LES). The motion was approved unanimously.**

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Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 3:40 p.m.

Respectfully Submitted,

Juliano Freitas,

Secretary

ADDING VS COMBING BENEFITS FROM TRANSMISSION UPGRADES: ROUND 2

ESWG: April 10, 2014; Mike Proctor

Overview: A More Condensed/Simpler Approach to Additive vs Combined

Additive

Economic Benefits always includes 100% APC Savings*

- Economics the Driver
  - TB = EB + AVCosts
  - EB = 100%
  - AVCosts can be positive or zero
- Reliability/Policy Driver & AVCost = 0
  - TB = DCost + EB
  - EB = 100%
  - DB = DCost
- Reliability/Policy the Driver & AVCost > 0
  - TB = DCost + EB + AVCost
  - EB = 100%
  - DB = DCost
  - OB = AVCost

Combined

Economic Benefits always includes 100% APC Savings*

- Economics the Driver
  - TB = EB + AVCosts
  - EB = 100%
  - AVCosts can be positive or zero**
- Reliability/Policy Driver & AVCost = 0
  - TB = max{EB, DCost}
  - EB = 100%
  - DB = TB – EB
- Reliability/Policy the Driver & AVCost > 0***
  - TB = DCost + EB
  - EB = 100%
  - DB = DCost – αAVCost
  - OB = αAVCost

Where $0 \leq \alpha \leq 1$ is set so that DB ≥ OB

TB = Total Benefit; EB = Economic Benefit; DB = Direct Benefit; OB = Other Benefit;
DCost = Driver Cost; AVCost = Avoided Cost (eliminated avoided need)

*This is not a change to original version

** One case in which Additive and Combined disagree on AVCost

*** . Assumes EB are additive.- alternative is complex and is discussed at slide 17

Critical Assumptions

1. Classification of Projects
2. Use of Avoided Cost
3. Importance of Least-Cost

1. Classification of Projects

- Project meets a defined need:
  - Reliability – the project fixes a reliability issue (e.g., N-1 violation)
  - Public Policy – the project meets in part or in total the integration of wind into the SPP Market (e.g., 97% of available wind)
  - Economic – the project addresses a top congested flowgate and has economic benefits ≥ project costs.
- But what happens when a project meets multiple needs? Some examples:
  - A reliability project reduces curtailment on some wind farms
  - A public policy project changes the need for a reliability upgrade; in essence reduces the costs for reliability upgrades
  - A reliability or public policy upgrade reduces congestion on a top congested flowgate
  - An economic project replaces a reliability or policy project

1. Classification When Meeting Multiple Needs

- Classification by Project Driver (Primary Need Met by the Upgrade):
  - If a project contributes to meeting more than one need, how should the driver be determined for purposes of classification?
  - For consistency is a set of rules (Business Practices) needed to address project classification when multiple needs are being met in whole or in part?
- Assumed Basic Classification Rules for this Presentation
  - Economic: Any project that addresses a top congested flowgate and has economic benefits ≥ project cost.
  - Reliability: Any cost-effective (least-cost) project that was designed to address a reliability need.
  - Policy: Any cost-effective (least-cost) project that was designed for the purpose of decreasing wind curtailment.
- Other Possibilities to Consider – Projects Modified from Least Cost
  - Project that are modified to address multiple needs
    - Reliability or Policy Project modified to ***no longer be least cost*** in meeting the driver need, but the incremental other benefits ≥ incremental costs.
      - Meeting additional needs at a lower net cost is "cost-effective," but no longer "least-cost" for the driver need.
    - Economic Project that is modified to address reliability or policy needs, where the incremental cost is less than the cost of the reliability or policy need that has been replaced.

2. Avoided Cost (AVCost)

- When the driver for a Reliability/Policy project is determined and that project is least cost for meeting the driver need:
  - DCost is least cost
- When the project in question meets the other need (in part or in total), this results in a decrease in least cost for meeting that other need, and
  - AVCost is decrease in least cost
  - This decrease in the least cost to meet the other need is what should be used to measure the other benefit.

3. Importance of Least-Cost

- Least-cost is critical to the determination of the benefits being considered for reliability or policy:
  - When the cost of an economic, reliability or policy project is increased to capture other benefits that exceed the incremental costs
    - Least-Cost insures that the benefit of the project driver (Reliability/Policy) is not overvalued; i.e., DCost is least cost
    - Least-Cost ensures that the base for the calculation of incremental costs is correct – if those incremental costs are incurred to meet reliability/policy needs, then incremental cost = benefit.
  - When making an avoided cost calculation – least cost ensures that the avoided costs are not overvalued; i.e., AVCost is least cost
  - For ensuring that the calculation of benefits being considered are not inflated; i.e., the MTFs intention in the words "cost-effective" is met.
- Least-cost for wind integration projects has been and will continue to be an issue.

Alternative for Wind Integration Benefits (for future consideration)

- **DETERMINE THE LEAST-COST FOR TRANSMISSION FOR WIND INTEGRATION USING A SEPARATE PLANNING STUDY THAT LOCATES WIND FARMS NEAR TO LOAD WITHIN EACH ZONE**
  - The details of modeling least-cost transmission for wind integration from wind farms near to load need to be presented at a later meeting.
- Policy benefits would equal these least costs plus any additional wind farm capacity cost savings from locating wind farms in the highest wind regions of SPP.
  - The details of wind farm capacity cost savings need to be presented at a later meeting.
- Why do this?
  - Allows for a one-time calculation of benefits that can then be allocated based on the timing of wind farms being integrated into the SPP footprint for meeting mandates and goals.
  - Avoids the problems associated with reliability or economic projects adding policy benefits; e.g., wind integration benefits from the Priority Projects
  - Assures that the costs being used are the least transmission costs for each zone
  - Much simpler to determine the allocation of benefits among multiple zones when compared to implemented policy projects that solve issues for multiple wind farms.
  - Gives larger benefits to zones located more distant from their designated wind farms.

Economic Benefits (APC)

Reliability/Policy Benefits Additive vs Combined

Principle: Including Full APC Benefits

- The Metrics Task Force recommended that Economic benefits should be included for all projects as additive benefits.
- While combining benefits does not follow this recommendation: **WHETHER ECONOMICS, RELIABILITY OR POLICY IS THE UPGRADE DRIVER, THE FULL VALUE OF APC SHOULD BE INCLUDED**
  - This includes both positive and negative benefits.
  - This approach allows the SPP Staff to simply run the APC calculations for the total portfolio.

Additive vs. Combined APC Benefits: Economics the Driver

- WHEN **ECONOMICS IS THE UPGRADE DRIVER** THE **AVOIDED COSTS** FROM REPLACED (DEFERRED OR DISPLACED) RELIABILITY OR PUBLIC POLICY PROJECTS SHOULD ALSO BE INCLUDED.
- **One Disagreement:** When either a reliability or policy is the upgrade driver and the APC savings are greater than the cost of the project and the project meets a need on a top congested flowgate: **SPP reclassifies the project as Economic**
  - Additive View: There are additional reliability/policy benefit because needs were met, and those benefits are equal to the least-cost of a project needed to meet that need.
  - Combined View. There are no avoided cost, so there are no additional benefits.
  - Other Considerations: The fundamental question is whether or not the project is the **least-cost project** to fix the reliability or policy problem
    - **If it is not**: It may be the ***best project*** to fix the reliability/policy issue, but not the least-cost project. In this case determine the least-cost project to fix the problem and the cost of that project becomes the avoided cost.
    - **If it is:** What if there is a reliability/policy project that was avoided, but only cost $100 less than the chosen project???
      - That project would clearly be avoided and its avoided cost included.
      - Why wouldn't reclassifying the project result in the same thing at just $100 more?

Combined APC Benefits: Economics Not the Driver

- Additive:
  - TB = EB + DB
  - DB = DCost
- When either **Reliability or Policy is the upgrade driver,** *if the concern is:* INCLUDING THE COST OF THE UPGRADE ALONG WITH APC BENEFITS IS INFLATING THE BENEFITS then:
  - Total Benefits may be limited to the max of Economic Benefits or project cost, and Driver Benefits set equal to the Total Benefits after subtracting out the Economic Benefits.
    - Total Benefits (TB) = max {EB, DCost}
    - Economic Benefits (EB) = 100% of APC Savings (100%)
    - Driver Benefits (DB) = TB - EB
      - If APC savings are greater than the cost of the project and the project is not reclassified as an Economic project, then the benefits from reliability/policy benefits = 0. This represents the Combined position for when the project is reclassified as an Economic Project (previous slide).

Reliability and Policy Benefits

When one type (Reliability/Policy) of upgrade is the driver and benefits occur to the other (Policy/Reliability), should the benefits be additive or combined?

When the Driving Project Results in Avoided Cost for the Other Project

- Both reliability and public policy projects relieve congestion on the transmission system.
  - In some instances, the relief of congestion can both relieve an infeasibility in the power grid (reliability) and reduce curtailment of power from wind farms (policy).
- When this happens it is possible to calculate the level of benefits from the non-driver by calculating the **avoided cost**
  - When one type drives the upgrade and it ***reduces the cost*** *of the* cost-effective (least-cost) upgrade for the other type.
    - The other upgrade is totally (100%) gone; or
    - The other upgrade is replaced by a less expensive upgrade, which would also include deferrals.
- In either case this is an AVOIDED COST calculation of benefit.

Why Avoided Cost Not Including Avoided Need?

- Avoided Need: In the previous presentation an example was given where a Reliability project reduced wind curtailments from 50% to 25%.
  - Recall λ = (50%-25%)/50% = 50%
  - The cost of the Policy project is then reduced because of this reliability upgrade – that reduction in cost is the AVOIDED COST.
  - In previous presentation
    - Policy Benefit = λ*Avoided Cost
- This was a mistake; Policy Benefit = Avoided Cost

Additive vs. Combined APC Benefits: Reliability/Policy the Driver

- Issue has been counting the cost of the project twice
  - This would only happen if the project fully met both a reliability and a public policy need – not a likely scenario.
  - The Avoided Costs for the other need are never greater than the least-cost for meeting that need, are below this if the need is not fully met, and are almost always below the cost of the driver project.
- Treatment of Benefits
  - Additive: Simply add the avoided cost to the total benefits
    - Total Benefits (TB) = EB + DB + OB
    - Economic Benefit (EB) = 100% APC
    - Driver Benefits (DB) = DCost
    - Other Benefits (OB)= AVCost
  - Combined: Assuming EB and DB are additive, subtract the avoided cost from the costs of the project driver and use the following:
    - Total Benefits (TB) = EB + DCost
    - Economic Benefit (EB) = 100% APC
    - Driver Benefits (DB) = DCost – αAVCost
    - Other Benefits (OB) = αAVCost

    Where $0 \leq \alpha \leq 1$ is set to ensure DB $\geq$ OB

    Example: DCost =500, EB = 800 and AVCost = 300

    DB = 500 -300α and OB = 300α;

    if α =1, then DB = 200 and OB = 300

    Setting DB = OB gives 500 - 300α = 300α $\Rightarrow$ α = 500/600 = 5/6 & OB = 250 = DB

Combined Benefits When EB and DB are Not Additive

- Recall from slide 11:
  - Total Benefits (TB) = max {EB, DCost}
  - Economic Benefits (EB) = 100% of APC Savings (100%)
  - Driver Benefits (DB) = TB - EB
- If EB > DCost, then TB = EB and DB = OB = 0

  Example: DCost = 800, EB = 1,000 and AVCost = 300

  TB = EB = 1,000; DB = 0; OB = 0
- If EB < DCost, then DCost – EB ≥ 0
  - DB = DCost – EB – αAVCost
  - OB = αAVCost

    Where $0 \leq \alpha \leq 1$ is set to keep DB ≥ OB

  Example: DCost =1,000, EB = 800 and AVCost = 300

  DB = 1,000 – 800 - 300α = 200 - 300α & OB = 300α

  Setting α = 1 gives OB = 300 and DB = 200

  Setting DB = OB $\Rightarrow$ 200 - 300α = 300α or α = 200/600 = 1/3 & OB = 100 = DB

For Alternative Wind Integration Benefits

- Wind integration benefits are independent of any specific project – based solely on the least-cost transmission for integrating wind power from farms located near load.
- Benefit for wind integration are included based on timing of amounts of wind integrated into the SPP and ownership of wind farms by utilities.
- Then, the reliability benefits for any project receiving an NTC can be calculated and classified as either driver benefits or avoided cost benefits.
  - If driver benefits – then they are added
  - If avoided cost benefits – then either added or combined depending on ESWG preference.

Decision Elements/Summary

1. DCost & AVCosts calculated at least cost
2. EB = 100%
3. EB is driver ⇒ AVCosts are additive
4. R/P driver and no Avoided Costs from P/R
   a. Additive: DB = DCost
   b. Combined: DB = DCost - EB
5. R/P driver and P/R Avoided Costs
   a. Additive : DB = DCost & OB = AVCost
   b. Combined(3.a):

      DB = DCost - αAVCost & OB = αAVCost

   a. Combined(3.b):

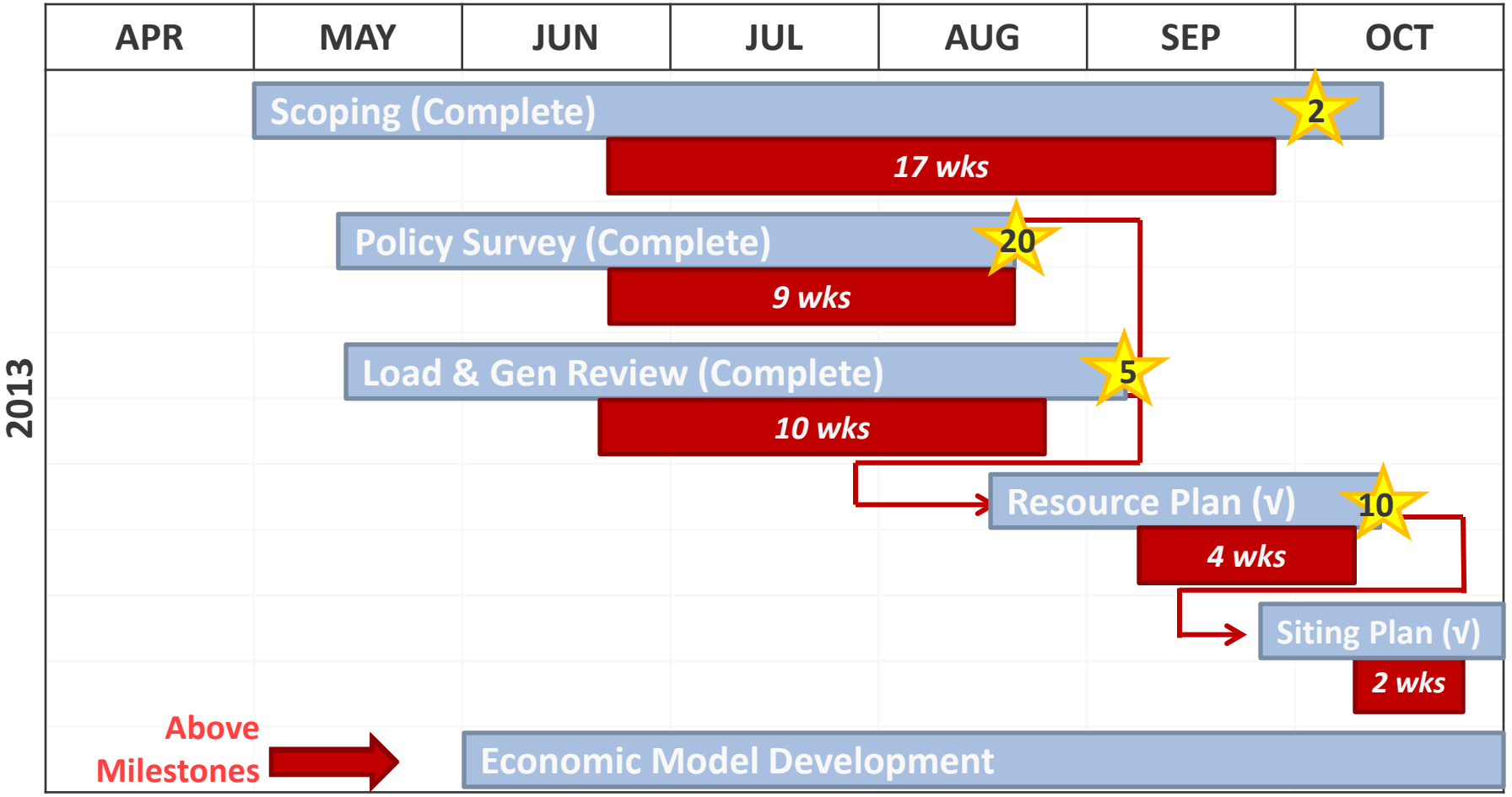
      DB = max{DCost – EB - αAVCost,0} & OB =min{DB, αAVCost}

2015 ITP10 Schedule

April 10th, 2014

SPP Southwest Power Pool

ITP10 Milestone Schedule (Apr-Oct 2013)

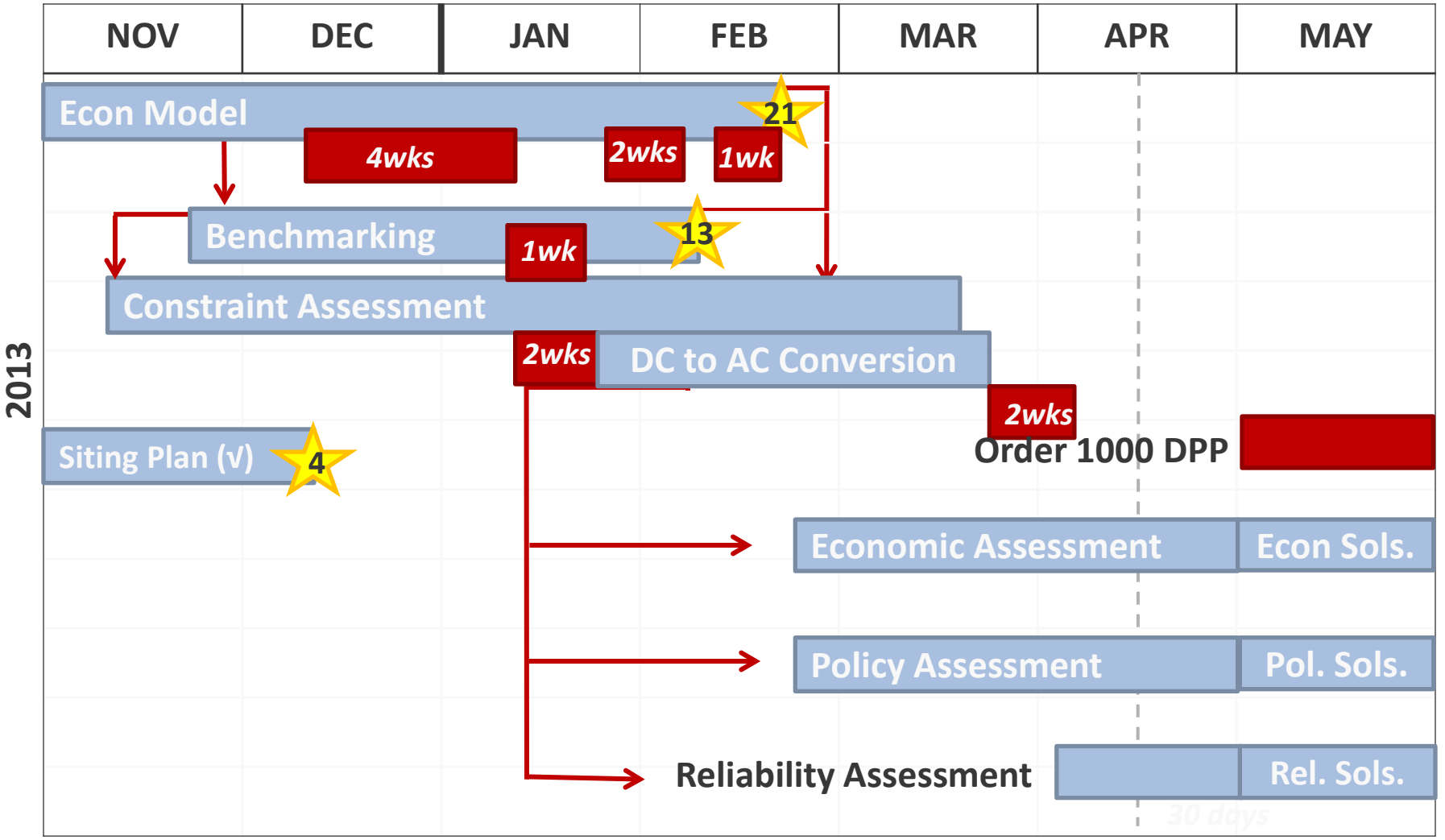


ESWG Approval

Member Review/Feedback Period

Milestone Period

ITP10 Milestone Schedule (Nov 2013-May 2014)

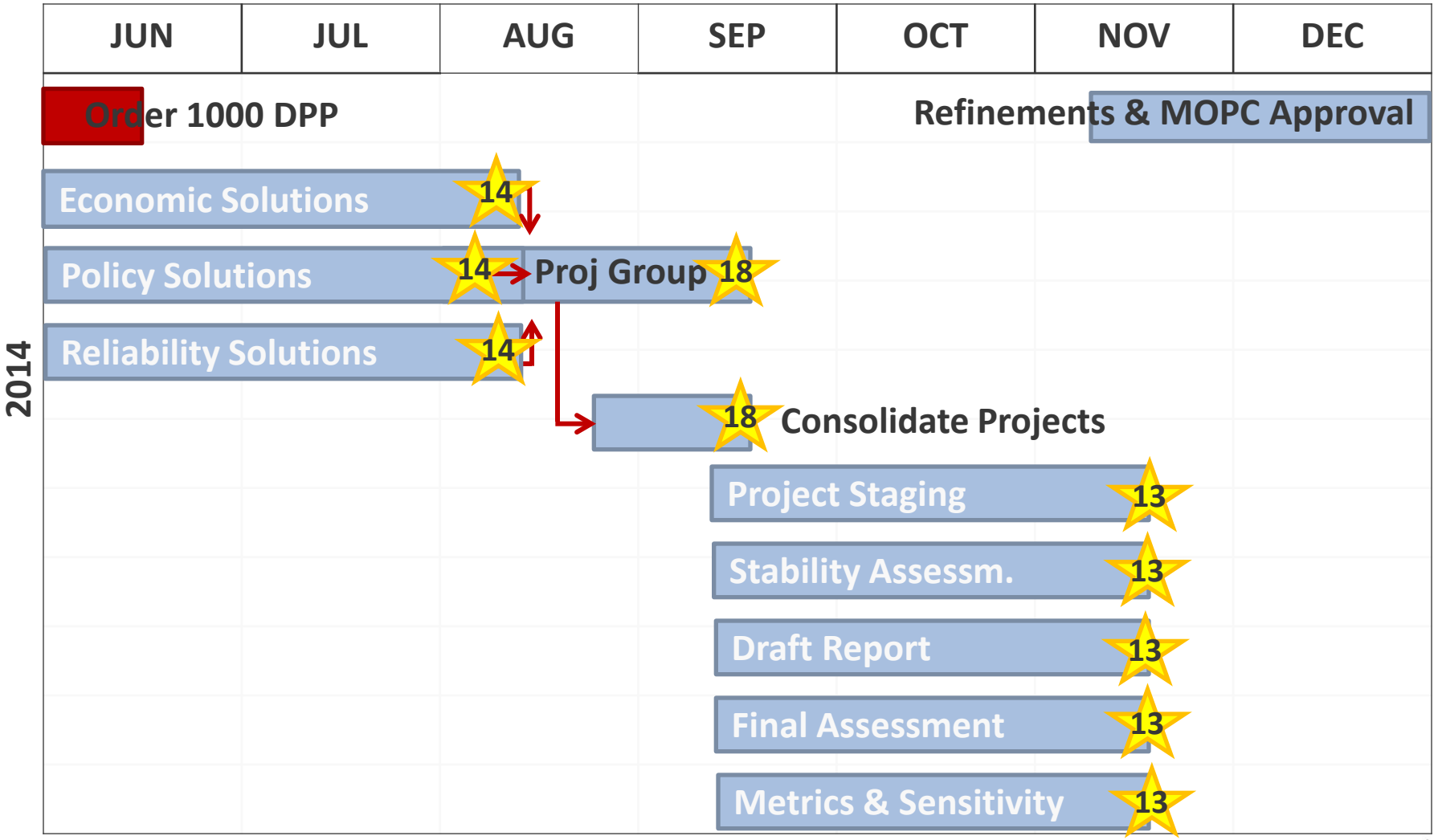


ESWG Approval

Member Review/Feedback Period

Milestone Period

ITP10 Milestone Schedule (Jun-Dec 2014)



ESWG Approval

Member Review/Feedback Period

Milestone Period

Schedule Options

- Three Options Proposed:
  - Option 1 (approved by TWG): DPP window opens at May 9th, Staging complete at Oct 15th
  - Option 2: DPP window opens at May 16th, Staging complete at Oct 22nd
  - Option 3: DPP window opens at May 23rd , Staging complete at Oct 29th

Option 1

	Option 1 (TWG Approval)	
	Start	**Finish**
DDP Opens	9-May	8-Jun
Evaluate/create Solutions	9-Jun	13-Aug
Project Groupings	14-Aug	5-Sep
Consolidate	8-Sep	23-Sep
Staging	24-Sep	15-Oct

Option 2

	Option 2	
	Start	**Finish**
DDP Opens	16-May	15-Jun
Evaluate/create Solutions	16-Jun	20-Aug
Project Groupings	21-Aug	12-Sep
Consolidate	15-Sep	30-Sep
Staging	1-Oct	22-Oct

Option 3

	Option 3	
	Start	**Finish**
DDP Opens	23-May	22-Jun
Evaluate/create Solutions	23-Jun	27-Aug
Project Groupings	28-Aug	19-Sep
Consolidate	22-Sep	7-Oct
Staging	8-Oct	29-Oct

Risks

- Final Reliability Assessment
- TWG/ESWG Approvals
- Benefit Metrics Calculation
- ITPNT/ITPNT CBA
- Final Report Approval

ITP10 Milestone Schedule - Summary

Task Name	Start	Finish	Member Feedback	ESWG Approval	
Scoping	April	October	17 weeks	10/2	
Policy Survey	May	August	9 weeks	12/04	
Load and Generation Review	May	September	10 weeks	9/5	
Resource Plan	August	October	3 weeks	12/04	2013
Siting Plan	September	October	2 weeks	12/04	
Economic Model development	June	February	7 weeks	Feb 21/2014	
Benchmarking	November	January '14	1 week	Feb 13/2014	
Constraint assessment - TWG Approval	November	March '14	1 week		
DC to AC Conversion of Peak Hours	January	March	2 weeks		
Reliability Assessment	March	May	30 days		
Reliability Solutions	May	July		Aug 14/2014	
Economic assessment	February	May	30 days		
Economic Solutions	April	July		Aug 14/2014	
Policy Assessment	February	May	30 days		
Policy Solutions	April	July		Aug 14/2014	
Stability Assessment	September	October			2014
Project Grouping	July	August	1 week	Sep 18/2014	
Consolidate Projects	August	September		Sep 18/2014	
Project Staging	September	October		Nov 13/2014	
Draft Report	July	November	3 weeks	Nov 13/2014	
Final Assessment	September	November		Nov 13/2014	
Benefit Calculation	September	November	3 weeks	Nov 13/2014	
Refinements and MOPC Presentation	November	January '15			

Metrics Review

April 10th, 2014

SPP Southwest Power Pool

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

Overview

- ESWG has been tasked with reviewing the calculation of metrics going forward
  - ITP10
  - RCAR 2
- Today – continue discussion of metrics that have been developed previously
  - Focus will be on the calculation of metrics that have received more attention from stakeholders during ITP and the previous RCAR

Approved Metrics for the RCAR

- Adjusted Production Cost (APC) Savings
- Reduction of Emission Rates and Values
- Savings due to Lower Ancillary Service Needs and Production Costs
- Avoided or Delayed Reliability Projects
- Capacity Cost Savings due to Reduced On-Peak Transmission Losses
- Mitigation of Transmission Outage Costs
- Assumed Benefit of Mandated Reliability Projects
- Public Policy Benefits

ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

Reliability Benefit Allocation Methodologies

- **Highway/Byway – utilized in RCAR**
- **DFAX**
- **LODF**
- **System Reconfiguration**

*These allocation methodologies do not impact the total reliability benefit of projects. They only impact the allocation of benefit to zones.

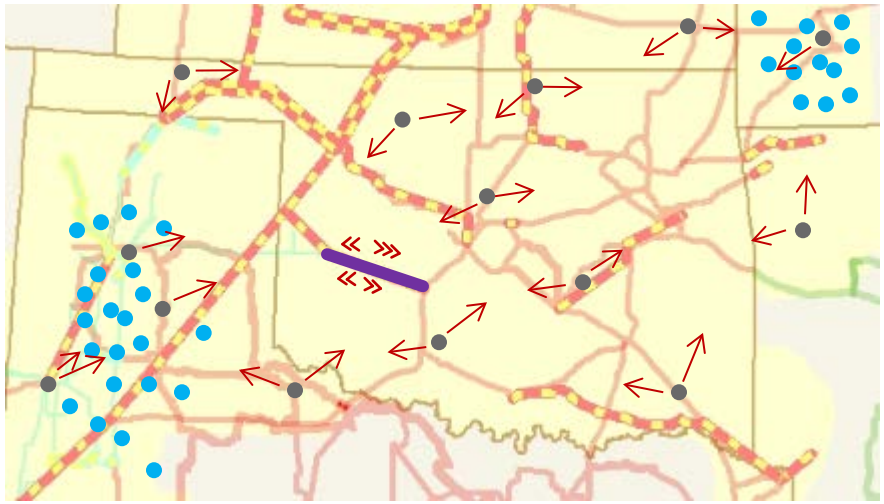
Highway/Byway Approach

- Benefits would be allocated in the same manner costs are allocated
- For upgrades > 300 kV:
  - 100% of benefit allocated to the region, based on Load Ratio Share (LRS)
- For upgrades between 100 kV and 300 kV:
  - 1/3 of benefit allocated to the region, based on LRS
  - 2/3 of benefit allocated to the zone
- For upgrades < 100 kV:
  - 100% of benefit allocated to the zone

DFAX Approach

- Distribution factors (DFAX) used to calculate the portion of a transfer of energy from a defined source to a defined sink that will flow across a specific transmission facility
- A DFAX is calculated for each transmission zone by modeling a transfer from all generation in the SPP region individually to the loads in each transmission zone
- The change in flow for the reliability upgrade was calculated for each of the zonal transfers
- DFAX represent a measure of the use by the load of each transmission zone of the required Reliability Project as determined by power flow analysis

DFAX Approach



Large DFAX -> large benefit

Small DFAX -> small benefit

DFAXs for each of the 16 transfers are normalized to develop allocation factors. These allocation factors are then normalized based on peak load by zone to obtain final allocation factors.

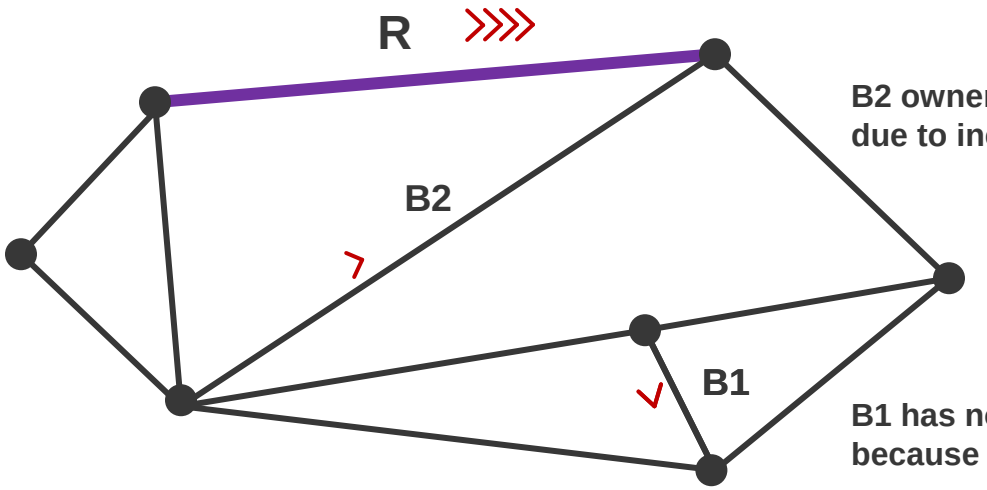
Zones with transfers that impact the reliability upgrade flow the most will have the most benefit.

Line Outage Distribution Factor (LODF) Approach

- N-1 Contingency Analysis
- Change in flow for Reliability Upgrade computed for each outage (LODF)
- Increase in flow for Reliability Upgrade due to Zone A Outage is credited as benefit to Zone A
- Sum of LODFs by zone are normalized to compute allocation factors by zone

LODF Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



B2 owner is assigned benefit, due to increased flow on R

B1 has no impact on benefit, because flow on R stays same

Outage taken for every branch, 1 by 1, and increase in flow on R is measured

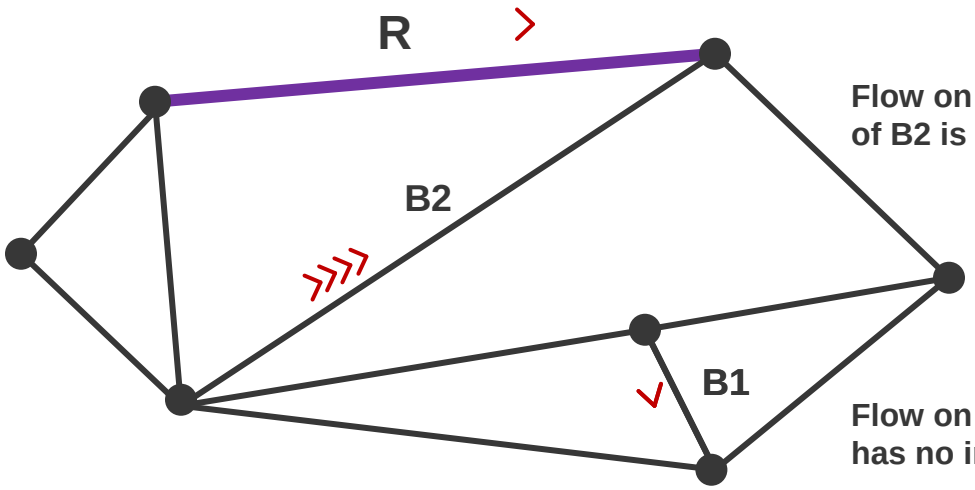
Benefits assigned to zones based on who owns the outaged facilities that cause increases in flow on R

System Reconfiguration Approach

- This approach is modified form of the MW-mile cost allocation utilized prior to Highway/Byway
  - This approach does not utilize line lengths
- Analyze all flows both with and without the reliability upgrade
  - Lines with increased flows after reliability upgrade is outaged are identified as beneficiaries of the reliability upgrade
  - Zones that own these lines are credited with reliability benefit
  - Approach and results are very similar to LODF

System Reconfiguration Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



Flow on B2 increases, owner of B2 is assigned benefit

Flow on B1 stays the same. B1 has no impact on benefit.

Flow on every branch is analyzed, 1 by 1, to determine if flow increased as a result of R being outaged

Benefit assigned to zones based on who owns the branches with increased flow after R is outaged

PJM Allocation Method

Cost Allocation Example

- 5 LDAs
- 1 upgrade (U1) resolves one or more criteria violations
- DFAX cutoff = 1%
- Usage: 80%/20% of U1 MWh is projected to be in the positive/negative direction

LDA	Peak Load (MW)	DFAX on U1 (%)
1	10,000	5.0
2	6,000	-10.0
3	4,000	0.9
4	3,000	-3.0
5	2,000	10.0

Cost Allocation Example

Step	Reference	LDA 1	LDA 2	LDA 3	LDA 4	LDA 5	Total
1. Peak Load (MW)	From PJM Load Report	10,000	6,000	4,000	3,000	2,000	25,000
2. DFAX	From DFAX Analysis	5.0%	-10.0%	0.9%	-3.0%	10.0%	
3. Positive Impact (MW)	Line 1 * Line 2 if DFAX is >= 1% Else 0	500	0	0	0	200	700
4. Negative Impact (MW)	Line 1 * Line 2 if DFAX is =< -1% Else 0	0	-600	0	-90	0	-690
5. Positive Usage	Line 5 Total * Line 3 / Line 3 Total (Line 5 Total From Production Cost Simulation)	57.14%	0	0	0	22.86%	80%
6. Negative Usage	Line 6 Total * Line 4 / Line 4 Total (Line 6 Total From Production Cost Simulation)	0	17.39%	0	2.61%	0	20%
7. DFAX Allocation	Line 5 + Line 6	57.14%	17.39%	0%	2.61%	22.86%	100%

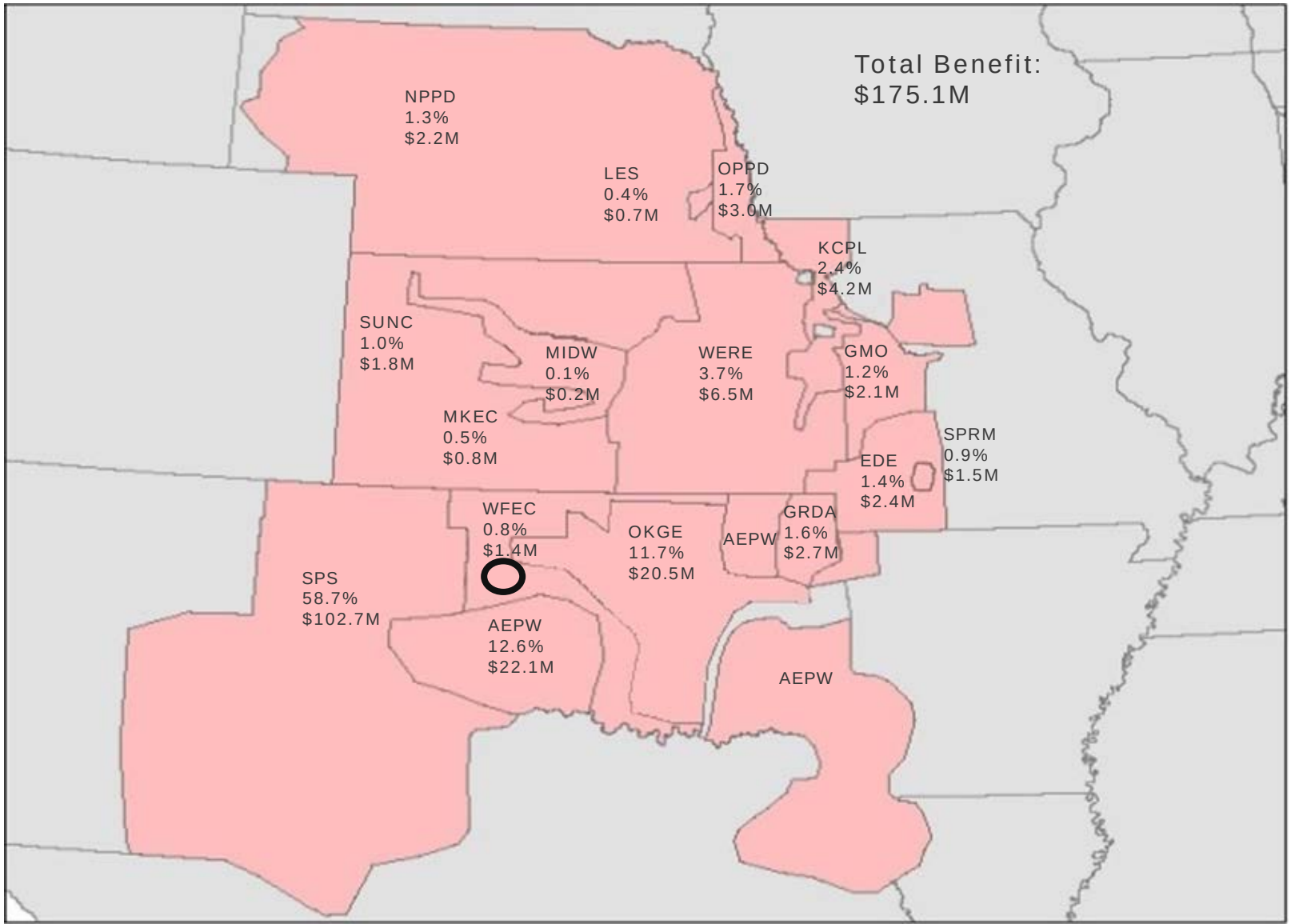
* For Regional and Necessary Lower Voltage Facilities greater than or equal to $5 Million, the allocation for each LDA will be the average of the DFAX allocation and the LDA load ratio share based on the appropriate Network Service Peak Loads.

This methodology was used for final allocations in the DFAX, LODF, and System Reconfiguration Approaches

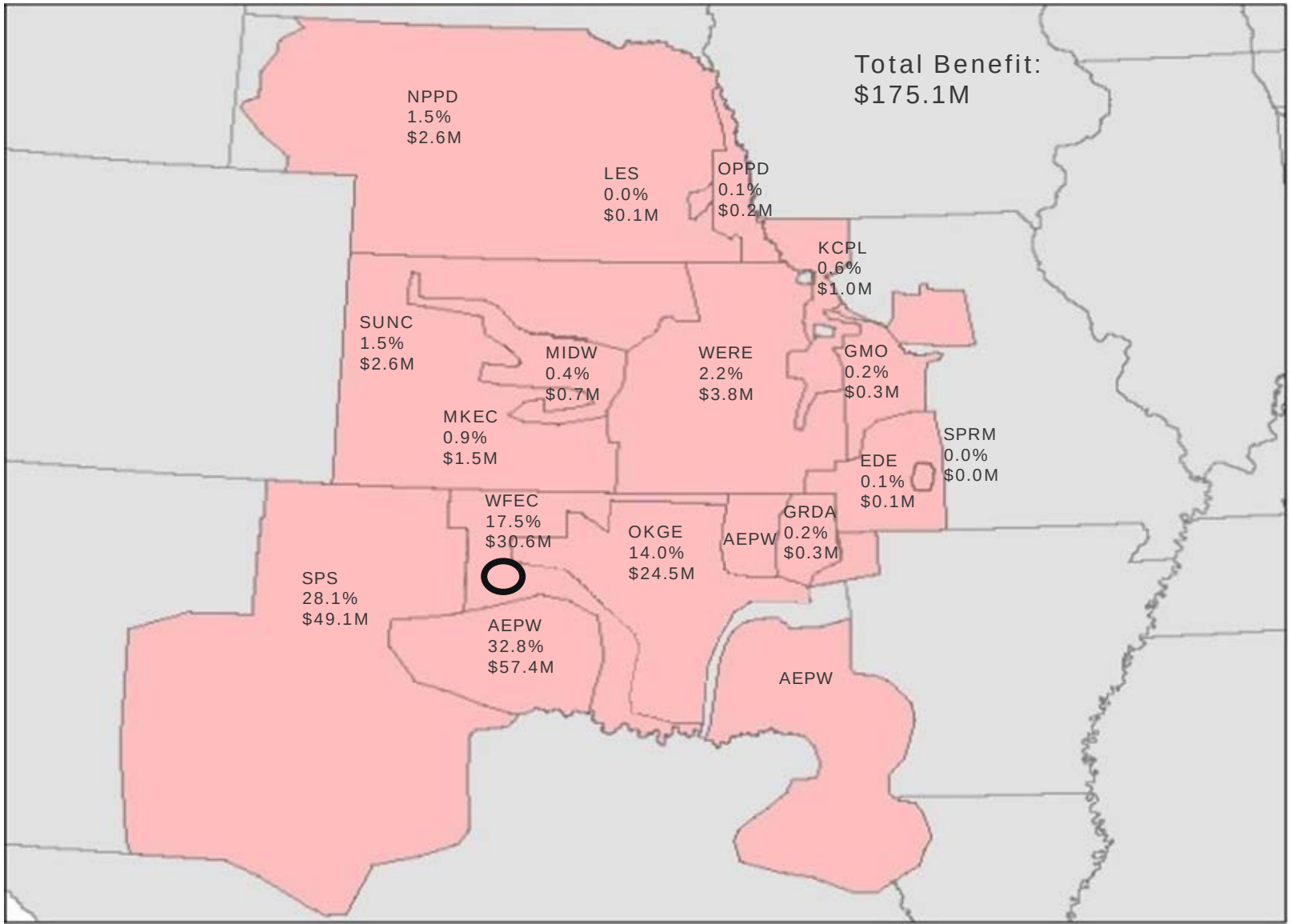
Examples

- Considered three existing reliability projects
  - Summit – Elm Creek 345 (central KS)
  - Elk City – Gracemont 345 (west OK)
  - Oronogo Jct – Riverton 161 (southwest MO)
- For each, compared the benefit allocation results using the different approaches
  - Highway/Byway – used in RCAR
  - DFAX
  - LODF
  - System Reconfiguration

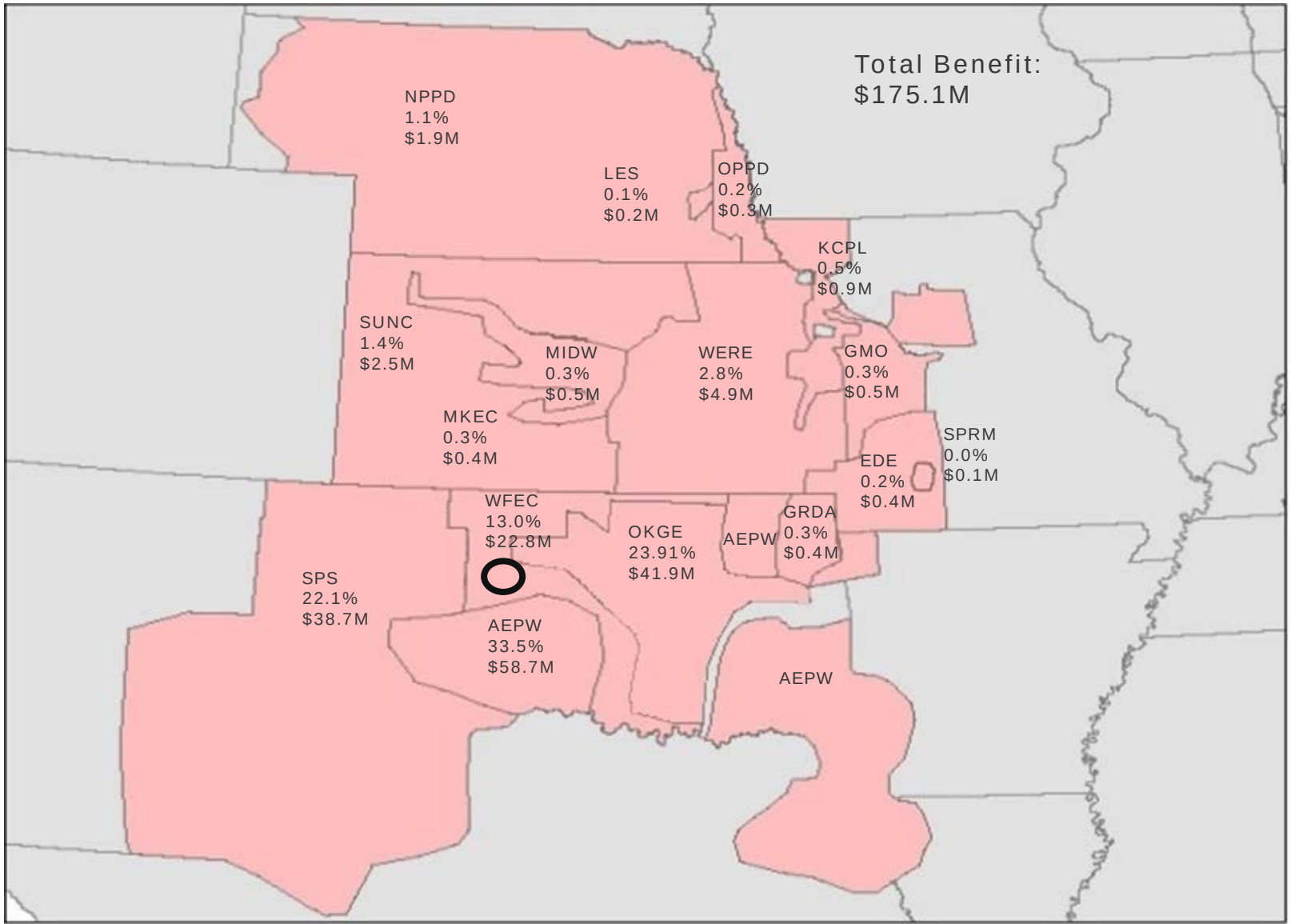
DFAX – Elk City to Gracemont 345 kV



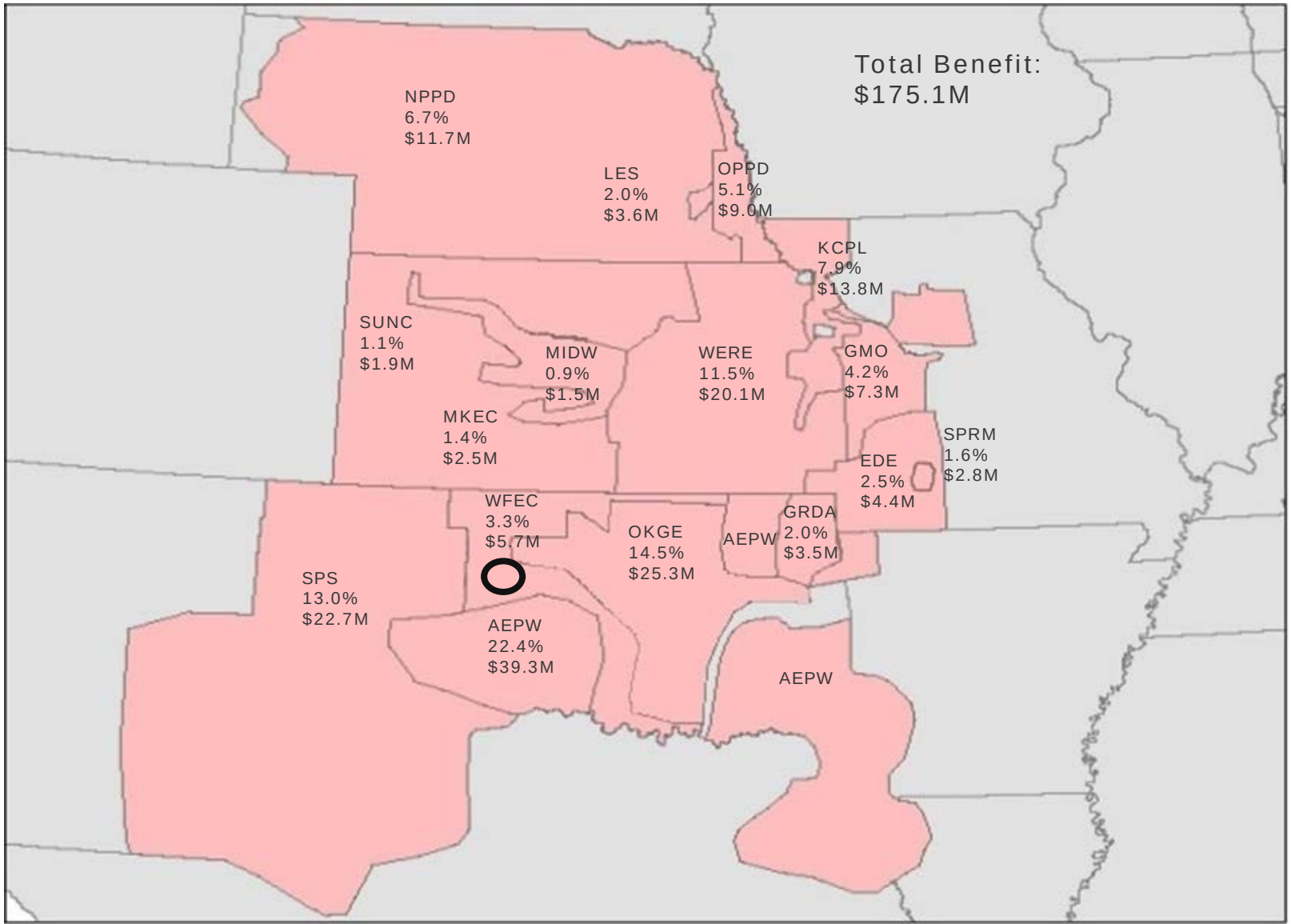
LODF – Elk City to Gracemont 345 kV



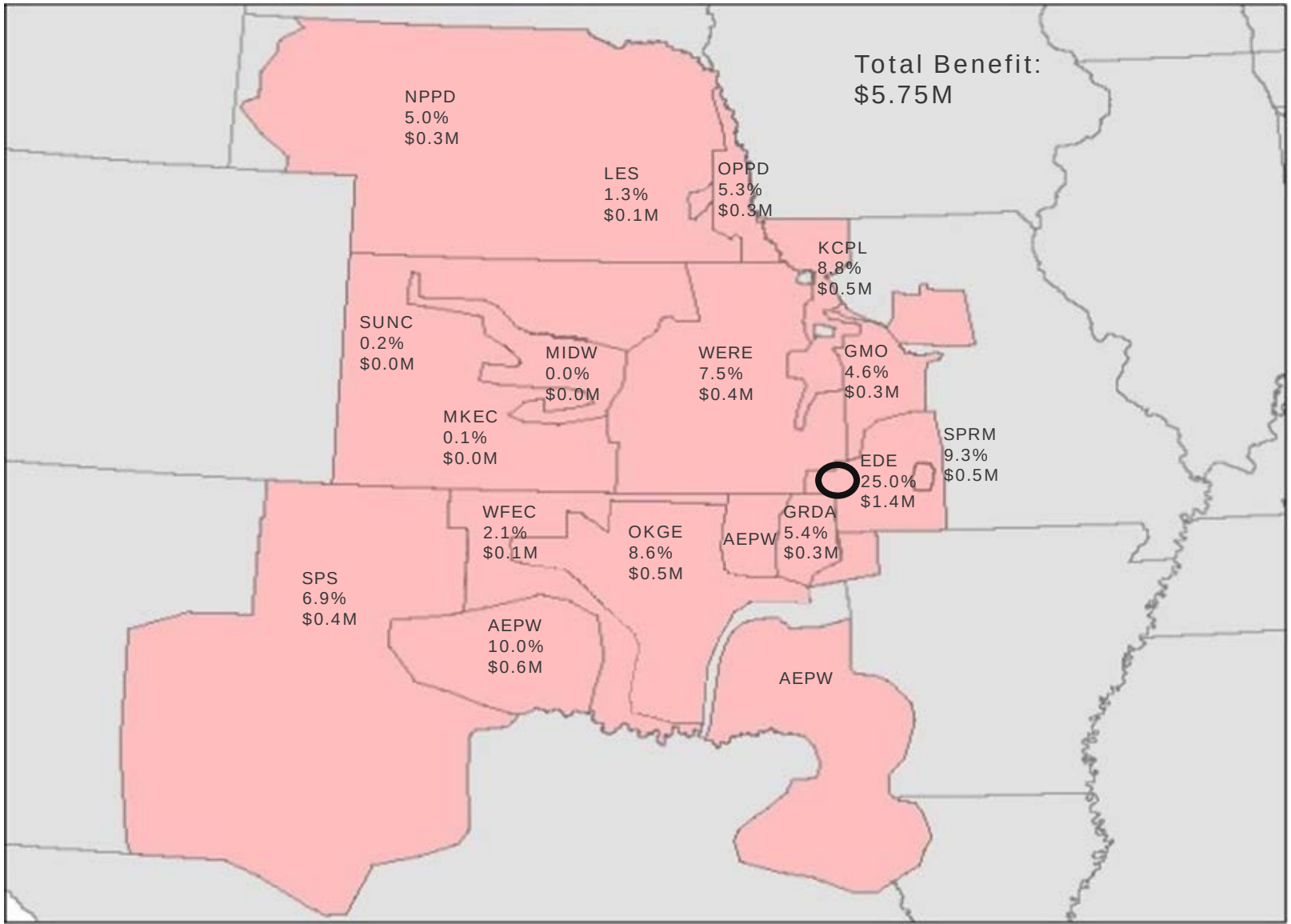
System Reconfiguration – Elk City to Gracemont 345 kV



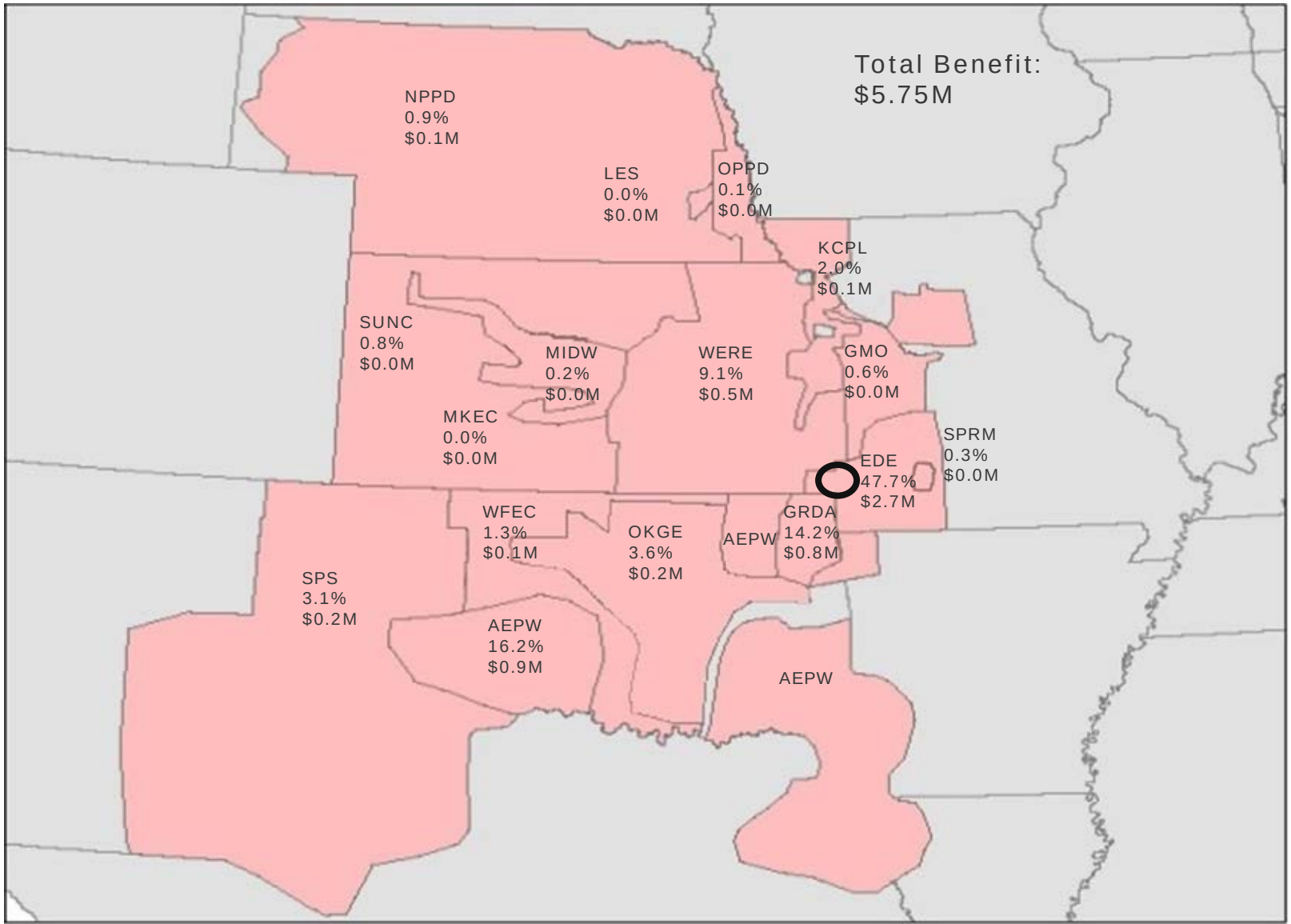
Highway/Byway – Elk City to Gracemont 345 kV



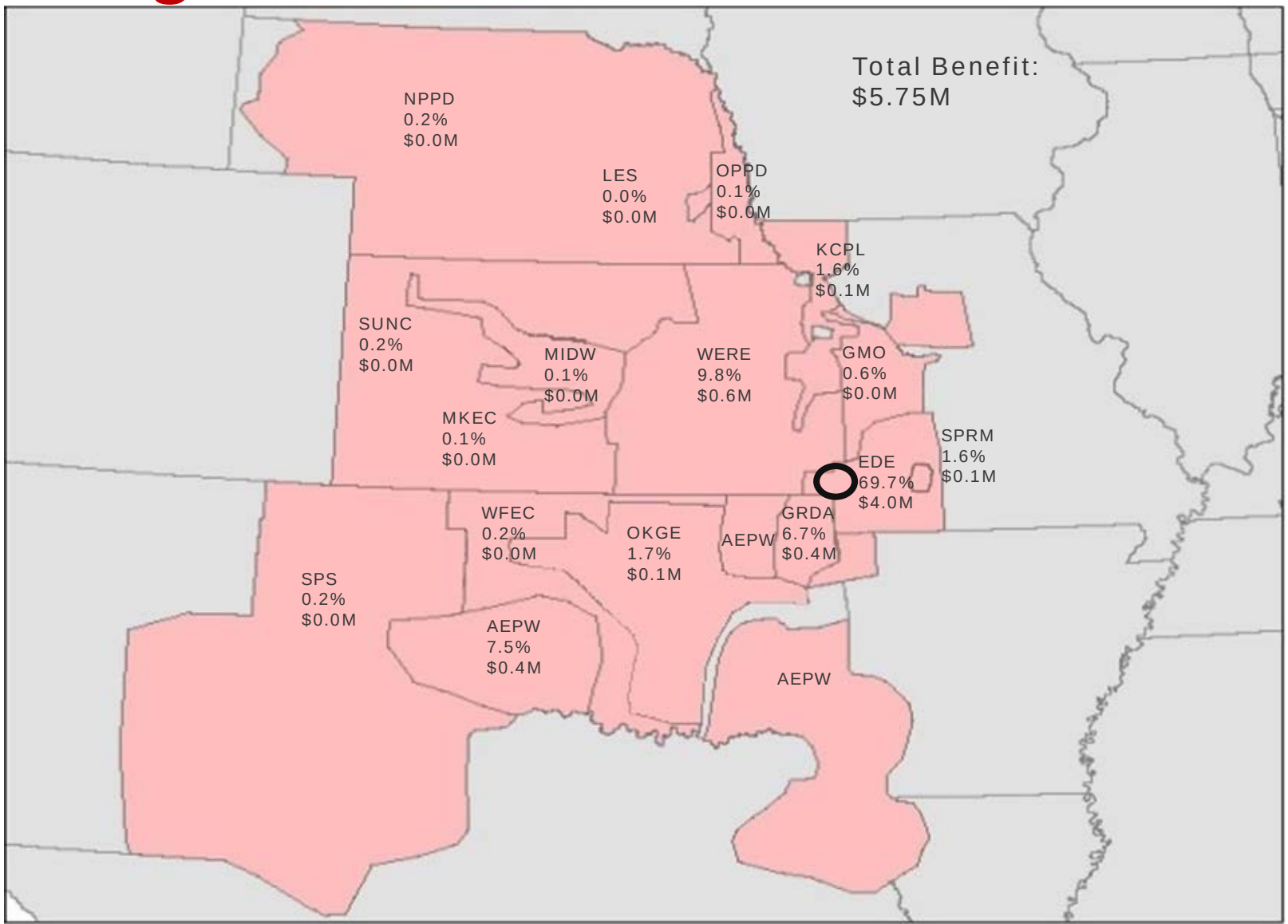
DFAX – Riverton to Oronogo 161 kV



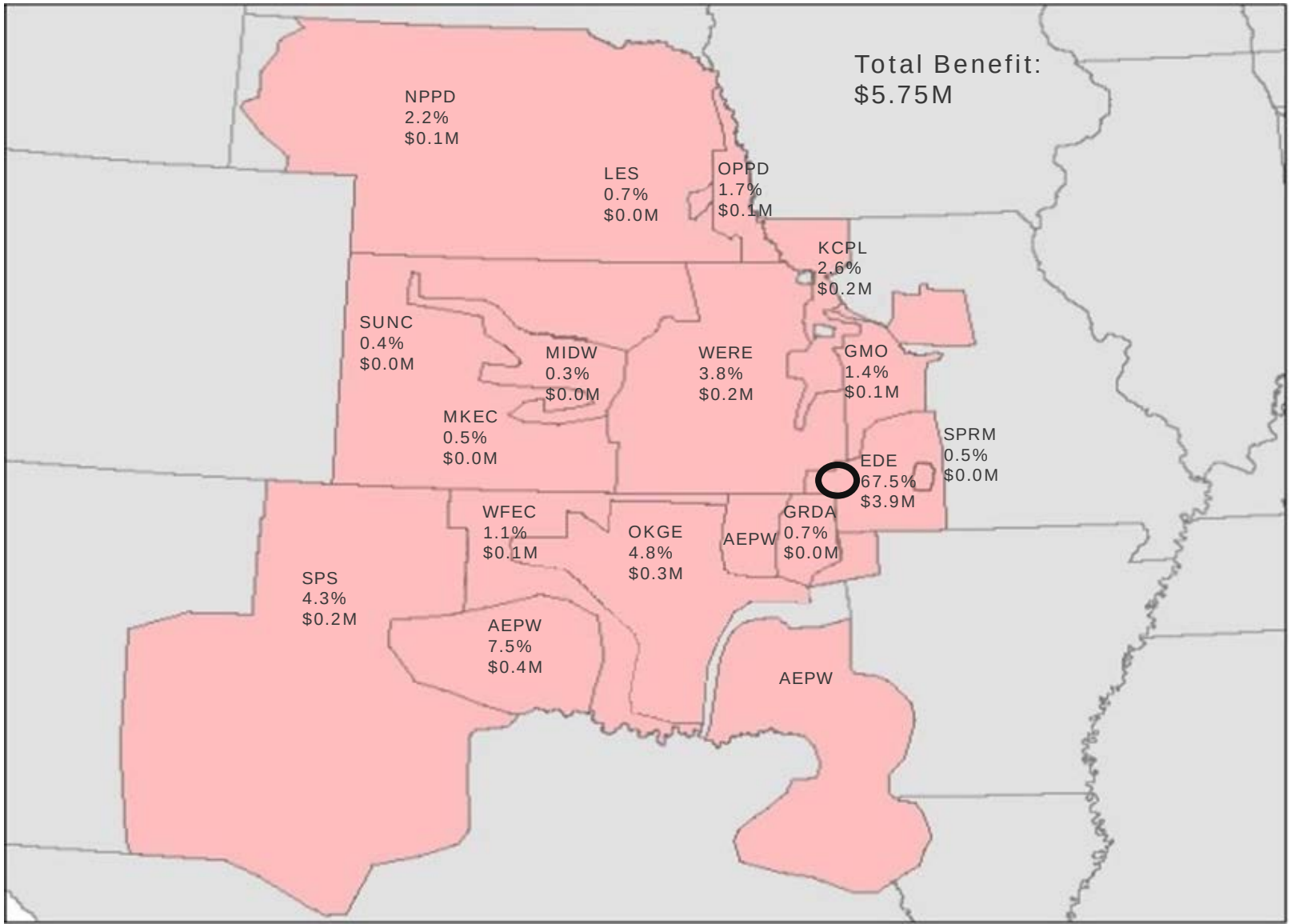
LODF – Riverton to Oronogo 161 kV



System Reconfiguration – Riverton to Oronogo 161 kV



Highway/Byway – Riverton to Oronogo 161 kV



Results Comparison – Elk City to Gracemont 345

Elk City - Gracemont 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$39,292,246	12.61%	$22,070,635	32.80%	$57,426,760	33.50%	$58,652,851
523	GRDA	2.01%	$3,523,360	1.56%	$2,732,454	0.18%	$308,351	0.25%	$441,514
524	OKGE	14.47%	$25,325,133	11.73%	$20,542,390	14.01%	$24,519,535	23.91%	$41,851,230
525	WFEC	3.27%	$5,723,806	0.82%	$1,442,962	17.49%	$30,623,101	13.00%	$22,763,222
526	SPS	12.98%	$22,725,093	58.67%	$102,707,267	28.07%	$49,143,574	22.11%	$38,711,584
531	MIDW	0.85%	$1,485,501	0.13%	$228,919	0.40%	$706,122	0.28%	$483,359
534	SUNC	1.08%	$1,893,089	1.00%	$1,757,112	1.48%	$2,587,438	1.44%	$2,513,189
536	WERE	11.48%	$20,100,127	3.73%	$6,527,446	2.19%	$3,836,896	2.81%	$4,919,923
540	GMO	4.18%	$7,318,366	1.21%	$2,123,400	0.19%	$329,406	0.27%	$471,908
541	KCPL	7.86%	$13,761,449	2.39%	$4,179,816	0.57%	$999,096	0.51%	$899,100
544	EMDE	2.53%	$4,430,995	1.38%	$2,422,150	0.08%	$146,083	0.20%	$357,008
546	SPRM	1.59%	$2,782,656	0.88%	$1,536,618	0.03%	$44,045	0.04%	$66,146
640	NPPD	6.69%	$11,706,991	1.29%	$2,249,917	1.49%	$2,613,735	1.10%	$1,925,600
645	OPPD	5.11%	$8,953,392	1.73%	$3,031,455	0.09%	$158,632	0.20%	$349,009
650	LES	2.03%	$3,555,862	0.40%	$706,349	0.04%	$78,612	0.12%	$208,336
539	MKEC	1.42%	$2,483,325	0.46%	$802,503	0.88%	$1,540,005	0.26%	$447,414
Total		100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392

Results Comparison – Summit to Elm Creek 345

Summit - Elm Creek 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$25,373,674	22.96%	$25,952,226	4.03%	$4,553,167	2.49%	$2,813,179
523	GRDA	2.01%	$2,275,273	2.93%	$3,316,056	0.52%	$586,534	0.46%	$523,117
524	OKGE	14.47%	$16,354,160	23.50%	$26,570,727	1.46%	$1,644,876	3.06%	$3,463,442
525	WFEC	3.27%	$3,696,250	6.75%	$7,627,840	0.44%	$496,188	0.46%	$522,626
526	SPS	12.98%	$14,675,137	32.20%	$36,401,169	3.82%	$4,317,980	0.29%	$324,247
531	MIDW	0.85%	$959,289	0.00%	$401	13.38%	$15,123,684	3.22%	$3,636,323
534	SUNC	1.08%	$1,222,496	0.00%	$479	14.63%	$16,536,242	18.64%	$21,067,896
536	WERE	11.48%	$12,980,018	9.44%	$10,677,305	33.07%	$37,386,161	52.24%	$59,057,673
540	GMO	4.18%	$4,725,966	0.00%	$2,998	0.76%	$854,705	0.75%	$848,003
541	KCPL	7.86%	$8,886,703	0.01%	$5,860	3.64%	$4,112,908	3.06%	$3,461,328
544	EMDE	2.53%	$2,861,394	1.57%	$1,773,728	0.17%	$192,165	0.29%	$323,853
546	SPRM	1.59%	$1,796,950	0.60%	$674,452	0.04%	$40,154	0.24%	$273,791
640	NPPD	6.69%	$7,560,000	0.01%	$12,617	6.38%	$7,211,929	4.41%	$4,981,700
645	OPPD	5.11%	$5,781,814	0.01%	$10,032	1.51%	$1,703,673	1.30%	$1,469,425
650	LES	2.03%	$2,296,261	0.00%	$3,177	0.27%	$299,720	0.66%	$746,945
539	MKEC	1.42%	$1,603,652	0.02%	$19,973	15.91%	$17,988,953	8.43%	$9,535,489
Total		100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038

Results Comparison – Riverton to Oronogo 161

Riverton - Oronogo Jct 161		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	7.48%	$430,193	9.97%	$573,526	16.23%	$933,380	7.48%	$430,259
523	GRDA	0.67%	$38,576	5.40%	$310,715	14.24%	$818,671	6.70%	$385,052
524	OKGE	4.82%	$277,273	8.55%	$491,670	3.58%	$205,656	1.65%	$95,045
525	WFEC	1.09%	$62,667	2.14%	$123,087	1.25%	$71,752	0.20%	$11,267
526	SPS	4.33%	$248,807	6.94%	$398,963	3.06%	$175,774	0.15%	$8,815
531	MIDW	0.28%	$16,264	0.03%	$1,926	0.21%	$11,918	0.06%	$3,168
534	SUNC	0.36%	$20,727	0.17%	$9,595	0.78%	$44,842	0.20%	$11,574
536	WERE	3.83%	$220,067	7.48%	$430,386	9.06%	$520,986	9.79%	$562,770
540	GMO	1.39%	$80,125	4.60%	$264,345	0.58%	$33,208	0.58%	$33,189
541	KCPL	2.62%	$150,668	8.75%	$502,903	1.97%	$113,406	1.60%	$92,086
544	EMDE	67.51%	$3,881,846	24.96%	$1,435,197	47.68%	$2,741,646	69.67%	$4,005,990
546	SPRM	0.53%	$30,466	9.29%	$534,013	0.33%	$18,923	1.56%	$89,502
640	NPPD	2.23%	$128,174	5.00%	$287,277	0.90%	$51,580	0.24%	$14,026
645	OPPD	1.70%	$98,027	5.28%	$303,698	0.10%	$5,563	0.05%	$3,066
650	LES	0.68%	$38,931	1.32%	$75,949	0.04%	$2,333	0.02%	$1,023
539	MKEC	0.47%	$27,189	0.12%	$6,753	0.01%	$362	0.06%	$3,168
Total		100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000

Comparison of Alternative Approaches

	DFAX	LODF	System Reconfiguration
Does it impact the total reliability benefit for a project?	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones
Does it measure how overloaded a line is or isn't?	No	No	No
Emphasizes use of the upgrade by…..	Zonal loads	Zonal branches	Zonal branches
Measures……	How much the upgrade is utilized in serving a zone's load	Additional flows that the upgrade will pick up when a zone's existing facilities are outaged	Additional flows that a zone's facilities will pick up when the upgrade is outaged
General allocation observation from examples	Allocation is slightly more levelized than the other two alternatives	Significant benefit going to a few zones closest to upgrade	Significant benefit going to a few zones closest to upgrade
Complexity in evaluating numerous projects	Moderate to difficult	Moderate	Moderate
Does it utilize PJM method of allocating based on how often flow on upgrade is positive or negative, and whether shift factor is positive or negative?	Yes	Yes	Yes
Other Notes	All SPP generators scaled. DFAX results were normalized based on peak load by zone	Similar to the System Reconfiguration approach, but a reverse variation of it.	Similar to the LODF approach, but a reverse variation of it. This is the MW-mile approach without accounting for mileage.

PUBLIC POLICY BENEFITS

Public Policy Benefits – Previous Approach

- Benefits allocated to zones in proportion to each zone's share of unmet renewable energy goals.
  - Public Policy Benefit per zone = (% share of unmet goals) x (cost of upgrade)
  - If a zone has no public policy mandate or goal, or already meets their mandate or goal, their public policy benefit is zero
- Production cost savings due to policy upgrades are additional to this benefit

Potential Alternative for Benefit Allocation

- Public Policy Benefit is allocated only to zones in the state in which the mandate/goal is driving the project
- New Gentleman – Cherry – Holt 345 kV line
  - Driven by Nebraska goal
  - Benefits allocated to Nebraska entities
  - Total 40-Year Cost = Public Policy Benefit = $296.4 M

	Unmet Renewable Goal* (MWh)	% Share of Unmet Renewable Goal	Public Policy Benefit (millions $)
NPPD	1,374,534	48%	$143
OPPD	1,470,070	52%	$153
LES	0	0%	$0
Total	**2,844,604**	**100%**	**$296**

*These numbers represent unmet goals from the RCAR; these are not up-to-date with ITP10 data

State Policy Benefit Allocation – Example

	Unmet Renewable Goal (MWh)	% Share of **SPP** Unmet Renewable Goal	Public Policy Benefit - RCAR ($M)	% Share of **Nebraska** Unmet Renewable Goal	Public Policy Benefit - State Policy Allocation ($M)
AEPW	1,787,126	10.1%	$30	0.0%	$0
CUS	0	0.0%	$0	0.0%	$0
EDE	887,873	5.0%	$15	0.0%	$0
GMO	1,737,706	9.8%	$29	0.0%	$0
GRDA	0	0.0%	$0	0.0%	$0
KCPL	2,906,537	16.4%	$49	0.0%	$0
LES	0	0.0%	$0	0.0%	$0
MIDW	0	0.0%	$0	0.0%	$0
MKEC	228,122	1.3%	$4	0.0%	$0
NPPD	1,374,534	7.8%	$23	48.3%	$143
OKGE	3,485,957	19.7%	$58	0.0%	$0
OPPD	1,470,070	8.3%	$25	51.7%	$153
SUNC	126,037	0.7%	$2	0.0%	$0
SWPS	0	0.0%	$0	0.0%	$0
WEFA	804,394	4.6%	$13	0.0%	$0
WRI	2,868,358	16.2%	$48	0.0%	$0
Total	17,676,714	100.0%	$296	100.0%	$296

*If a policy project enables members in multiple states to meet their mandates/goals, the benefit would be applied to all impacted members

MITIGATION OF TRANSMISSION OUTAGES

Mitigation of Outage Costs – Existing Approach

- Add set of historical transmission outages to production cost simulations
- Benefit = APC Benefit$_{\text{With Outages}}$ – APC Benefit$_{\text{Without Outages}}$
  - This metric is an adder to traditional APC Benefit
- Since it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone, this benefit is calculated on an SPP-wide basis and allocated to zones based on a load ratio share.

APC Savings Allocation Approach

- For APC Savings with no outages, calculate each zone's benefit as a percentage of the total SPP benefit
- Multiply each zone's APC benefit % by the Mitigation of Transmission Outage Costs total benefit to determine that zone's allocation of the Total Outage benefit

APC Savings Allocation Approach

	Mitigation of Transmission Outages Benefit - RCAR, based on LRS ($M)	APC Savings - 40-year NPV benefit* ($M)	Percent of Total APC Savings	Mitigation of Transmission Outages Benefit - allocated by APC Savings % ($M)
AEPW	$76	$240	7.9%	$27
CUS	$5	$7	0.2%	$1
EDE	$9	$7	0.2%	$1
GMO	$14	$23	0.8%	$3
GRDA	$7	$10	0.3%	$1
KCPL	$27	$24	0.8%	$3
LES	$7	$5	0.2%	$1
MIDW	$3	$60	2.0%	$7
MKEC	$5	$42	1.4%	$5
NPPD	$23	$226	7.5%	$25
OKGE	$49	$175	5.8%	$20
OPPD	$17	$34	1.1%	$4
SUNC	$4	-$10	-0.3%	-$1
SWPS	$44	$1,939	64.2%	$218
WEFA	$11	$24	0.8%	$3
WRI	$39	$215	7.1%	$24
Total	$340	$3,021	100.0%	$340

Historical Outage Data Approach

- Obtained operational data for outages from Sept 2011 to present
  - Number of outages by zone
  - Operations used different application before Sept 2011, making it more difficult to query and organize data prior to Sept 2011
  - Some tie lines are being double counted (~5% of outages)
- Number of outages by zone was divided by total outages for region to obtain allocation factor by zone
- Allocation factor multiplied by total outages benefit

Historical Outage Data Approach

Zone	# of outages	Allocation %	Benefit based on outage data ($M)	Benefit based on LRS, from RCAR ($M)	Increase in Benefit with new methodology ($M)
AEP	3,044	21.64%	$74	$76	($2)
EDE	545	3.88%	$13	$9	$4
GRDA	273	1.94%	$7	$7	($0)
KCPL	431	3.06%	$10	$27	($17)
LES	212	1.51%	$5	$7	($2)
MIDW	123	0.87%	$3	$3	($0)
GMO	393	2.79%	$10	$14	($4)
NPPD	1,492	10.61%	$36	$23	$13
OKGE	2,326	16.54%	$56	$49	$7
OPPD	434	3.09%	$10	$17	($7)
SUNC/MKEC	602	4.28%	$15	$9	$6
CUS	218	1.55%	$5	$5	$0
SPS	2,238	15.91%	$54	$44	$10
WFEC	399	2.84%	$10	$11	($1)
WR	1,334	9.49%	$32	$39	($7)
Total	14,064	100.00%	$340	$340	$0

INCREASED WHEELING THROUGH AND OUT REVENUES

Increased Wheeling Through and Out Revenues

- Increased ATC with neighbors can lead to increased through and out transactions, that can increase SPP wheeling revenues
  - Schedules 7, 8, 11
  - Metric does not capture the energy revenue from increased exports, only the wheeling revenue

Increased Wheeling – Calculation

- Increased Wheeling Benefit ($) = (Increased annual MWh exports) * (Average $/MWh Wheeling Charge)
  - Use PROMOD simulations to determine annual MWh exports in the base and change cases
  - Average $/MWh Wheeling Charge =

$$\frac{Total\ SPP\text{–}wide\ wheeling\ revenues\ for\ 2013}{Total\ MWh\ wheeling\ through\ and\ out\ transactions\ for\ 2013}$$

- MTF Recommendation: Allocate to zones based on Load Ratio Share

MARGINAL ENERGY LOSSES BENEFIT

Marginal Energy Losses Benefit

- Full MWh losses are not reflected in standard production cost simulations
- Energy loss savings can be calculated through post-processing of simulations
  - Based on Marginal Loss Revenues
- The calculation is performed for each zone

APPENDIX – METRICS REVIEW CALCULATIONS

DFAX Approach

For 10 MW transfer:

DFAX = (Post-transfer MW flow – Pre-transfer MW flow)/10 MW, in which:

- **Pre-transfer MW flow = MW flow over transmission upgrade before the 10 MW transfer**
- **Post-transfer MW flow = MW flow over transmission upgrade after the 10 MW transfer**

Wind units are excluded from the scaling

Units with GSF > 20% are excluded from the scaling

In this pass, ALL other generators were scaled up equally.

Transfers with positive DFAX are grouped together, and transfers with negative DFAX are grouped together

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Positive\ DFAX's}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) * \boldsymbol{LRS}, if\ DFAX_{Zone\ A}\ is(+)$$

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Negative\ DFAX's}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right) * \boldsymbol{LRS}, if\ DFAX_{Zone\ A}\ is\ (-)$$

(LRS = Load Ratio Share Percentage)

$$\boldsymbol{Reliability\ Project\ Benefit}\ (\$)_{\boldsymbol{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

LODF Approach

$$\sum Positive\ LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}$$, where

Post Contingent Flow > Pre Contingent Flow

$$\sum Negative\ LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}$$, where

Pre Contingent Flow > Post Contingent Flow

Post contingent flow (MW) = MW flow on reliability upgrade after contingency

Pre contingent flow (MW) = MW flow on reliability upgrade prior to contingency

LODF Approach

$$\boldsymbol{Allocation\ Factor_{Zone\ A}} = \left(\frac{\sum Positive\ LODF_{Zone\ A}}{\sum Positive\ LODF_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) +$$

$$\left(\frac{\sum Negative\ LODF_{Zone\ A}}{\sum Negative\ LODF_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right)$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)_{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

System Reconfiguration Approach

$$\sum Positive\ Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} +$$

$$\sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}, \text{where}$$

Post Contingent Flow $>$ Pre Contingent Flow

$$\sum Negative\ Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} +$$

$$\sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}, \text{where}$$

Pre Contingent Flow $>$ Post Contingent Flow

Post contingent flow (MW) = MW flow on system branch <u>after</u> reliability upgrade is outaged

Pre contingent flow (MW) = MW flow on system branch <u>prior to</u> reliability upgrade being outaged

System Reconfiguration Approach

$$\boldsymbol{Allocation\ Factor}_{\boldsymbol{Zone\ A}} =$$

$$\left(\frac{\sum Positive\ Relieved\ MW's_{Zone\ A}}{\sum Positive\ Relieved\ MW's_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) +$$

$$\left(\frac{\sum Negative\ Relieved\ MW's_{Zone\ A}}{\sum Negative\ Relieved\ MW's_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right)$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)}_{\boldsymbol{Zone\ A}}$$

$$= Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

Probabilistic Assessment 2014 Scope Overview

Seth Mayfield
501-482-2238
smayfield@spp.org

SPP Southwest Power Pool

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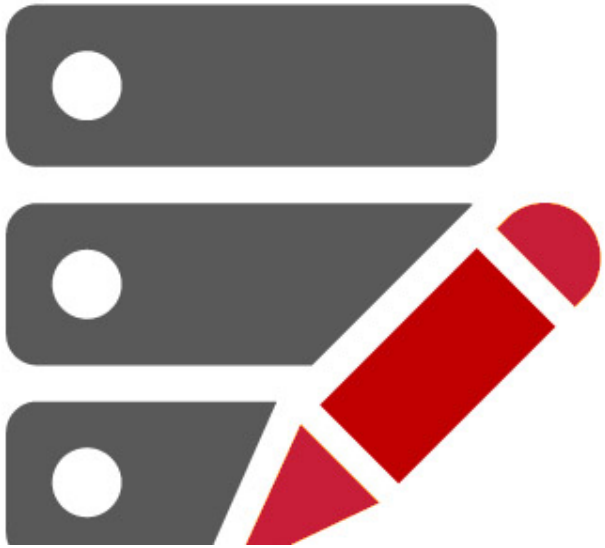
Points of Interest

- Process Steps
- Data inputs
- Assumptions
- Reporting
- Schedule
- Load forecast uncertainty model
- Averaging multiple load shapes

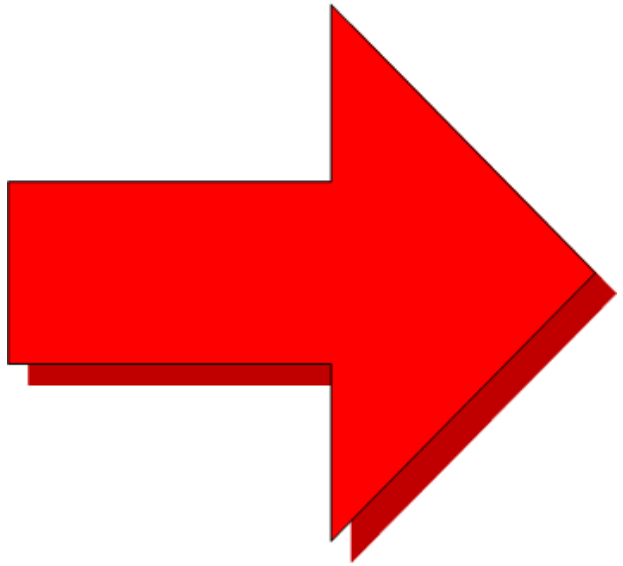
Process Steps

- Step 1: Create scope
- Step 2: Gather input data
- Step 3: Model data in GridView tool
- Step 4: Run simulation for SPP Balancing Authorities (BAs)
- Step 5: Evaluate results
- Step 6: Run simulation for the Consolidated Balancing Authority (CBA)
- Step 7: Evaluate results
- Step 8: Compile results into report
- Step 9: Present to Stakeholders for endorsement
- Step 10: Submit report to NERC



Data inputs

- Area load shapes
- Thermal / Renewable Generation data
- Wind Generation data
- Interface, Monitored branches, and Contingency data
- Purchases and Sales (Imports / Exports)
- Load Uncertainty data
- Transmission topology
- Emergency Operating Procedures

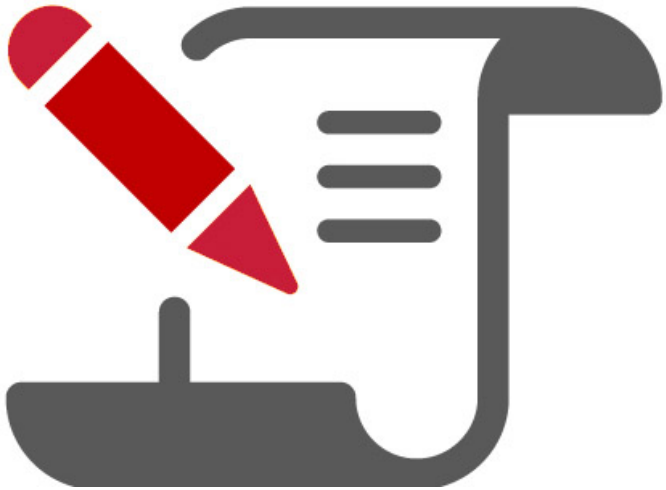


Assumptions

- Load shed penalty is $2000/MWh, Branch overload penalty is $6000/MWh.
- 2400 trials per simulation will be ran to get a proper convergence.
- Only Existing, Certain and Future, Planned reported generation are used as inputs from the LTRA.
- Future, Planned generation as stated in the LTRA is “firm and deliverable”.
- Uncertainty based generation outages are randomly selected.
- Operating reserve is 1700 MW.
- Spinning reserve is 50% of the Operating reserve.

Reporting

- Instances of LOLH, or LOLE above 0.1 days/year
- Finalized metric results (LOLH, LOLE, EUE, Normalized EUE)



Schedule

- 7/21/14: NERC releases LTRA data
- 9/25/14: 1st draft due to NERC
- 11/3/14: Final draft due to NERC
- 12/11/14: Draft Report presented to the ESWG for endorsement
- 1/6/15: Draft Report due to RAS- ProbA Team
- 1/23/15: Draft Report due to RAS

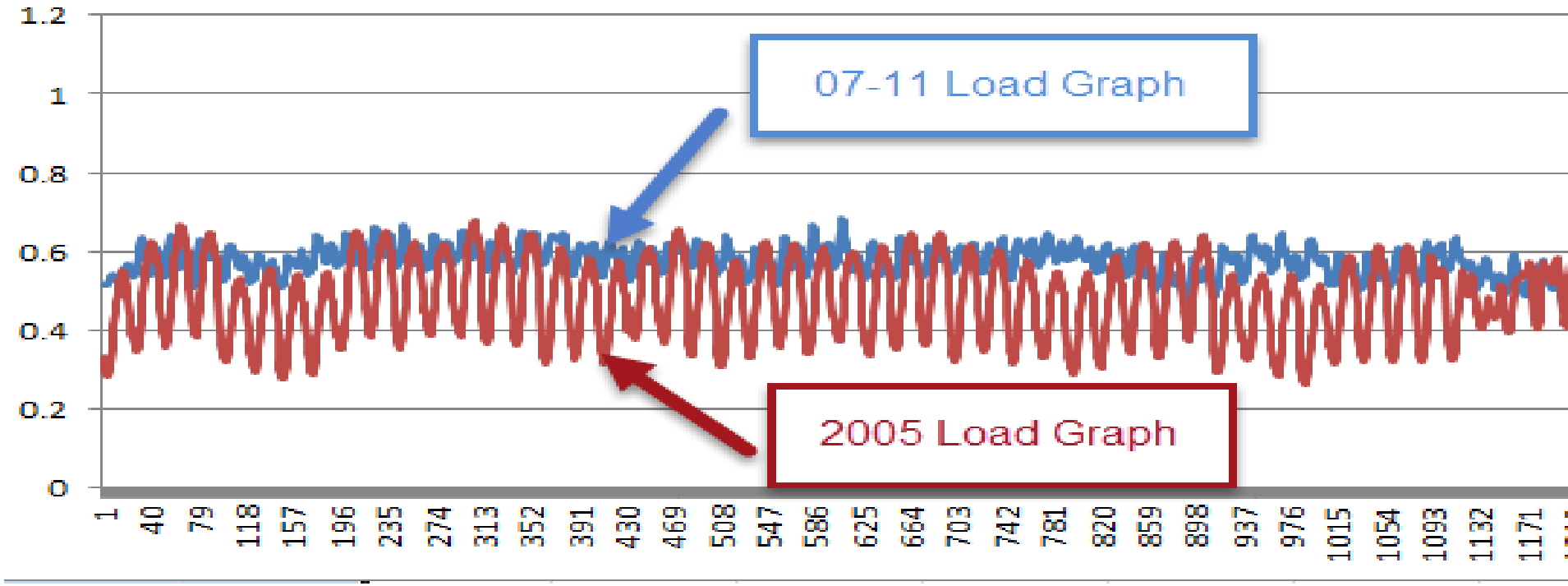
Load Forecast Uncertainty Model

- SPP staff recommends using 2006-2011 forecasted data, previously used in the previous NERC Probabilistic Assessment (2012 ProbA)

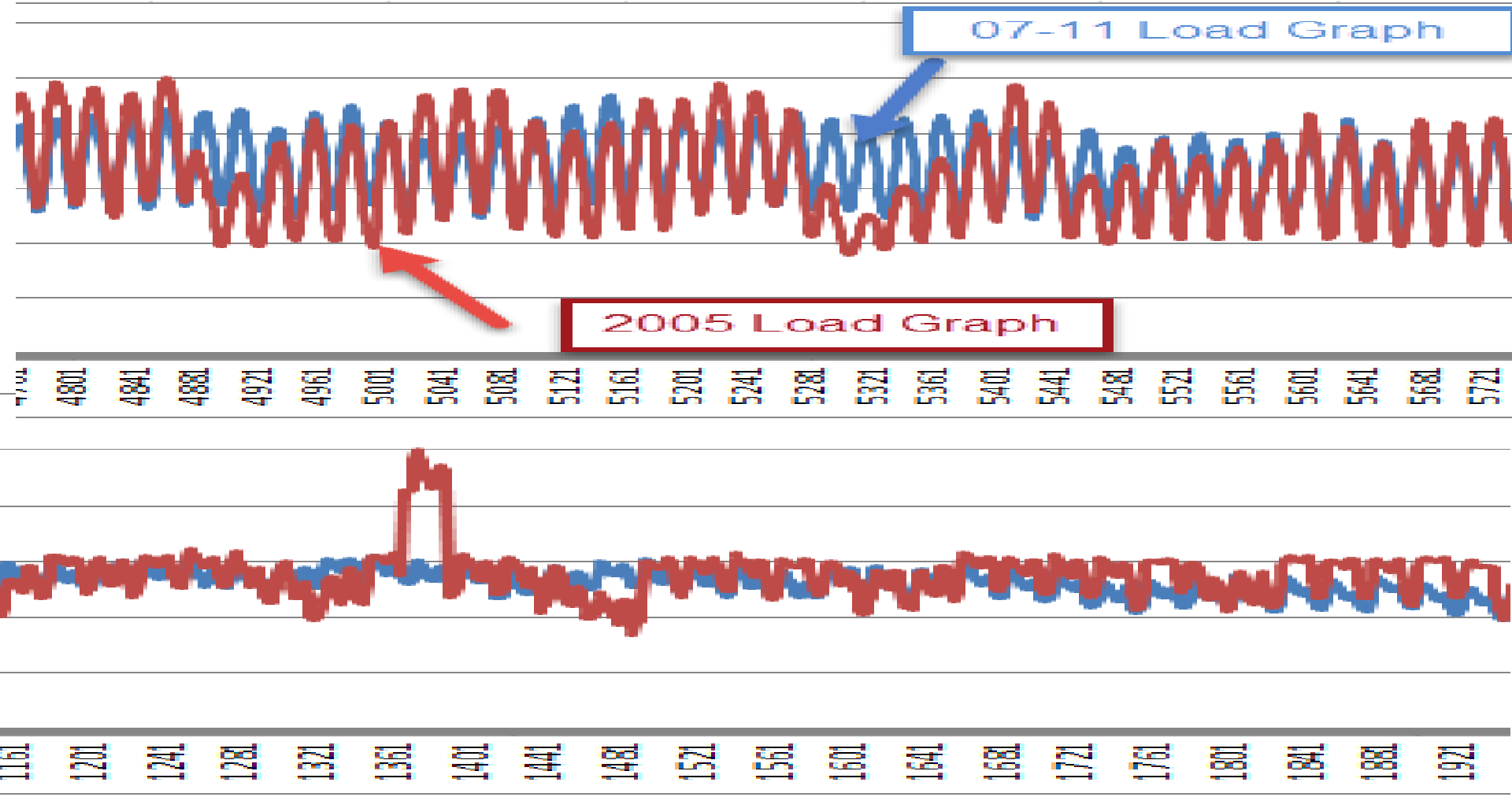
Averaged Load Shapes vs 2005

- Benefits of averaging multiple years
  - More realistic load shape
  - Off-peak events
  - Allows use of multiple years of wind data
- SPP staff recommends using 2007-2011 load and wind shapes

2007-2011 Average Load vs 2005



Sample sections of averaged vs 2005 shapes



HPILS Approval for MOPC

Al Tamimi

Jay Caspary

April 15, 2014

SPP Southwest Power Pool

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HPILS Scope

- Board directed staff to develop a plan to address high load increase expectations in a high priority study
- Grid topology based on existing system plus approved plans with a focus on restudy of suspended NTC-Cs
  - Tuco – New Deal 345 kV
  - Tuco – Amoco – Hobbs 345 kV
  - Grassland – Wolfforth 230 kV
- Member-driven load and resource plans
- Results will be utilized in 2015 ITP10
- Scope approved by Task Force, TWG and ESWG in June 2013, and MOPC in July 2013

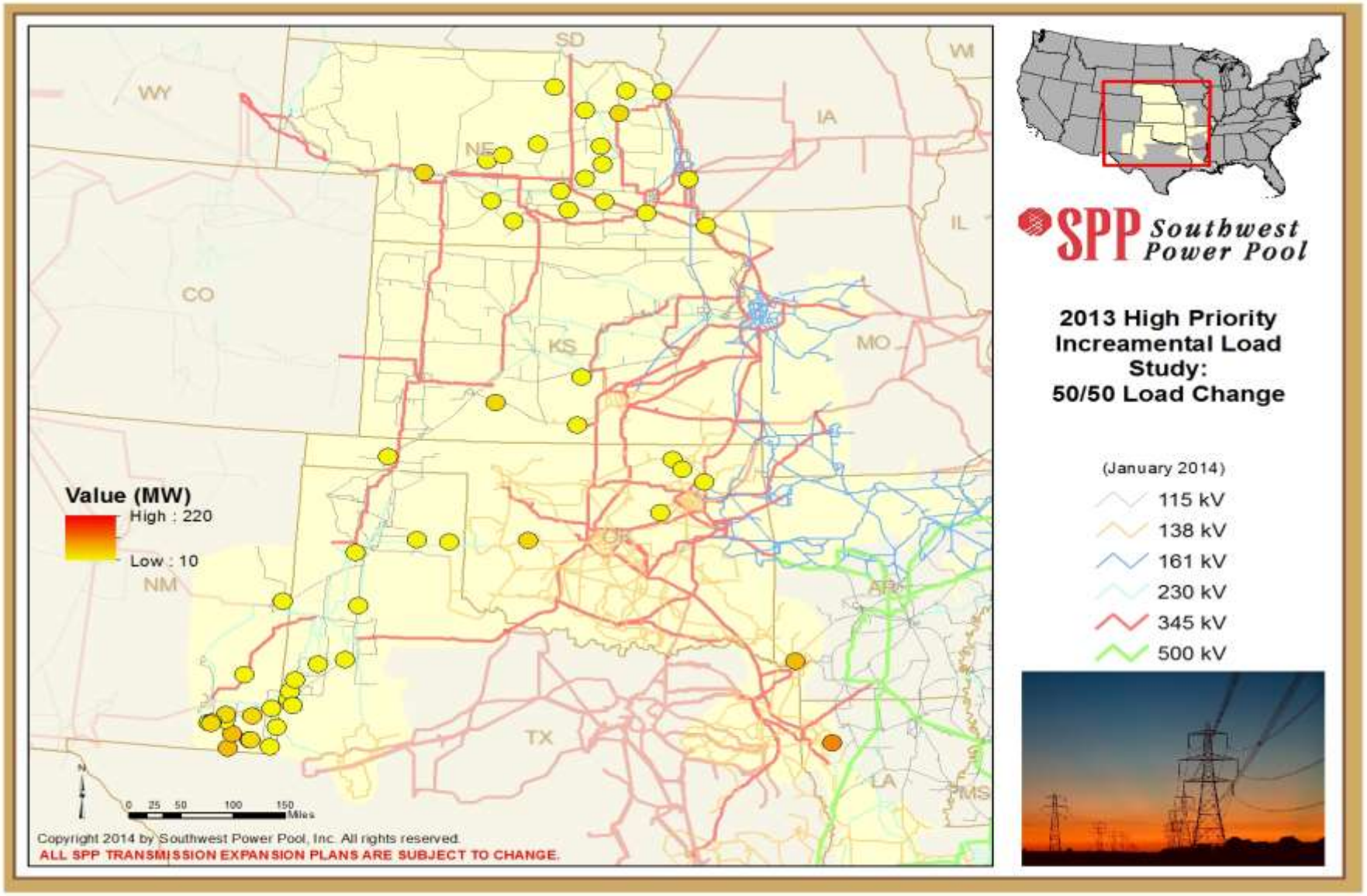
HPILS Highlights

- Approved scope required a focus on 2015, 2018, and 2023S N-1 reliability analyses and related 2018 and 2023 economic simulations
- Network upgrades identified to connect loads and integrate new resources prior to any reliability needs, with focus to exclude Base Plan funding for facilities related to generator outlet or select direct assigned/radial connections
- Completed analytics and finalized Portfolio of $1.5B of transmission expansion through 2023 to cost effectively address approved scope which reflects conservative standards.

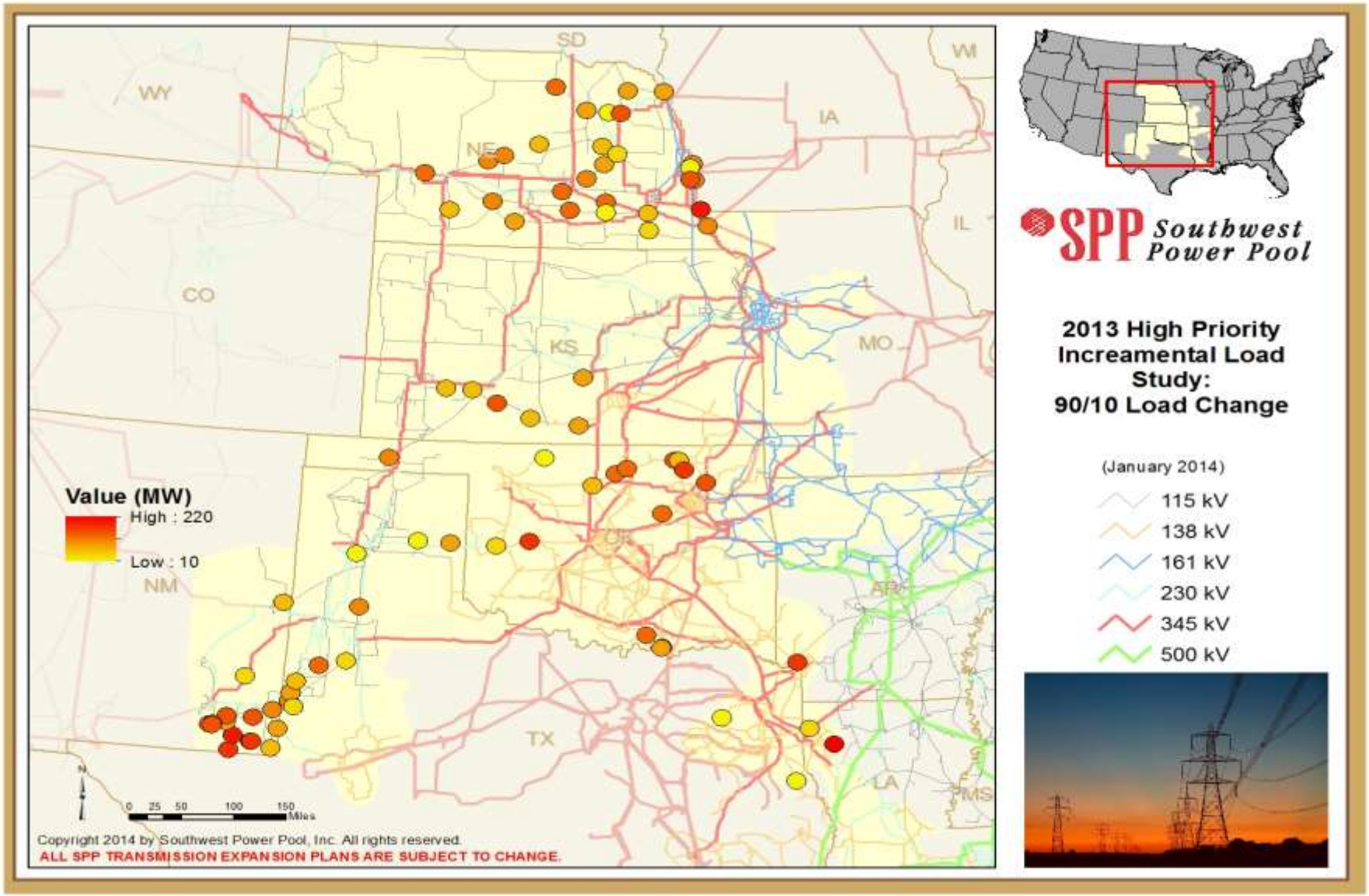
HPILS Recommendation

- Study recommends:
  - NTCs for $573M of Base Plan upgrades for reliability projects needed in the next 3 years; or for which financial commitments are needed prior to August 2015;
  - Issue NTCs for approximately $85M of projects which are direct-assigned or radials to connect HPILS loads that are not Highway/Byway funded
  - Withdraw suspended NTC-Cs for Tuco – New Deal and Grassland – Wolfforth projects saving $114M in E&C costs
  - Replace the existing $258M Tuco-Amoco-Hobbs suspended NTC-C which HPILS identified as a reliability need in 2020, with Tuco-Yoakum-Hobbs as a better performing solution saving at least $20M in E&C costs

Incremental Load Changes (50/50)



Incremental Load Changes (90/10)



Robust Growth in SPS

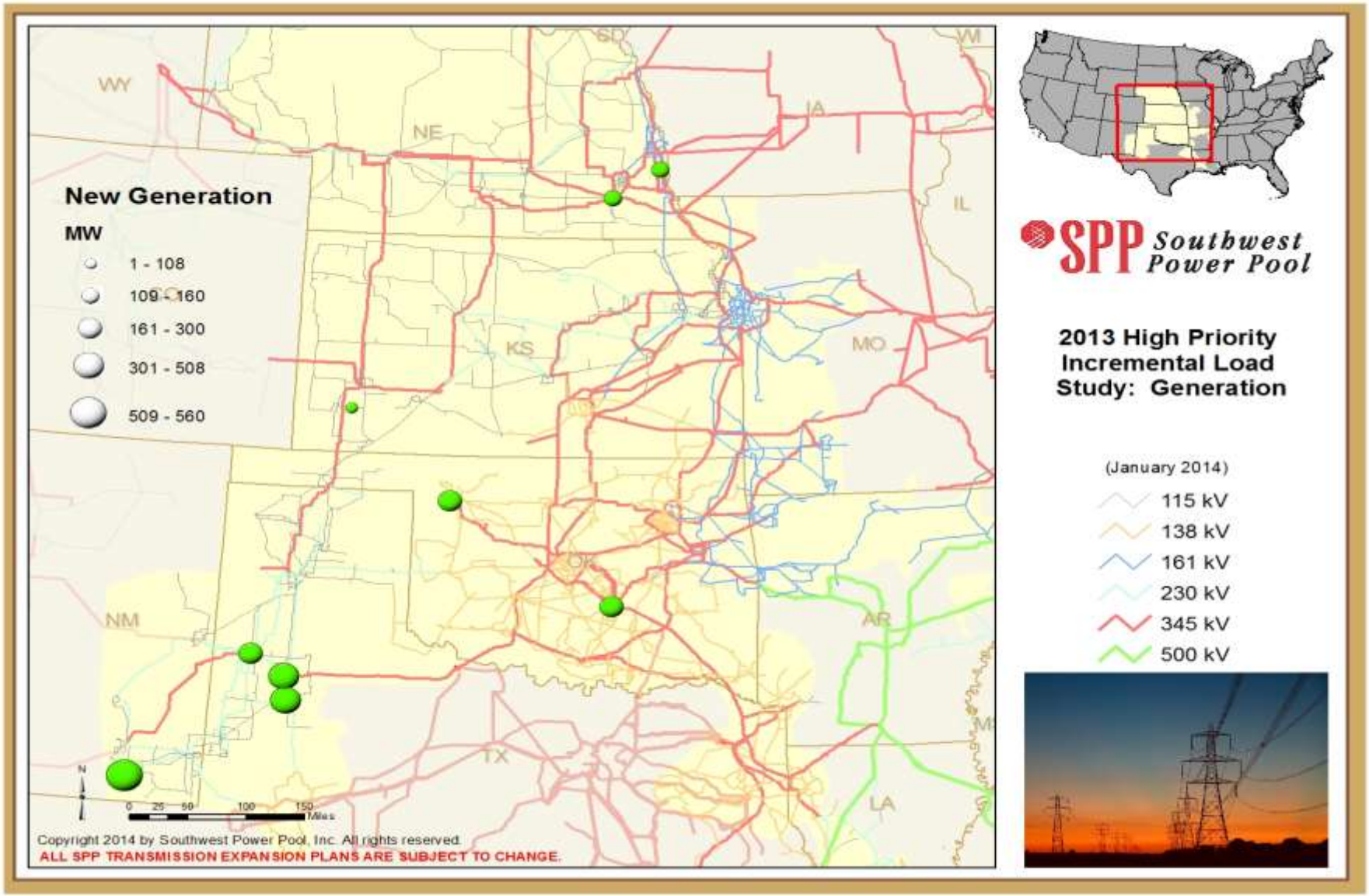
"SPS base retail load growth forecast is a robust 1.8% annually through 2020, but this is boosted to 3.6% when considering the potential for growth from the shale plays in New Mexico (Avalon) and the Panhandle (Anadarko wet gas). The booming oil and gas industry within SPS territory presents opportunities for both transmission and well as generation ratebase growth."

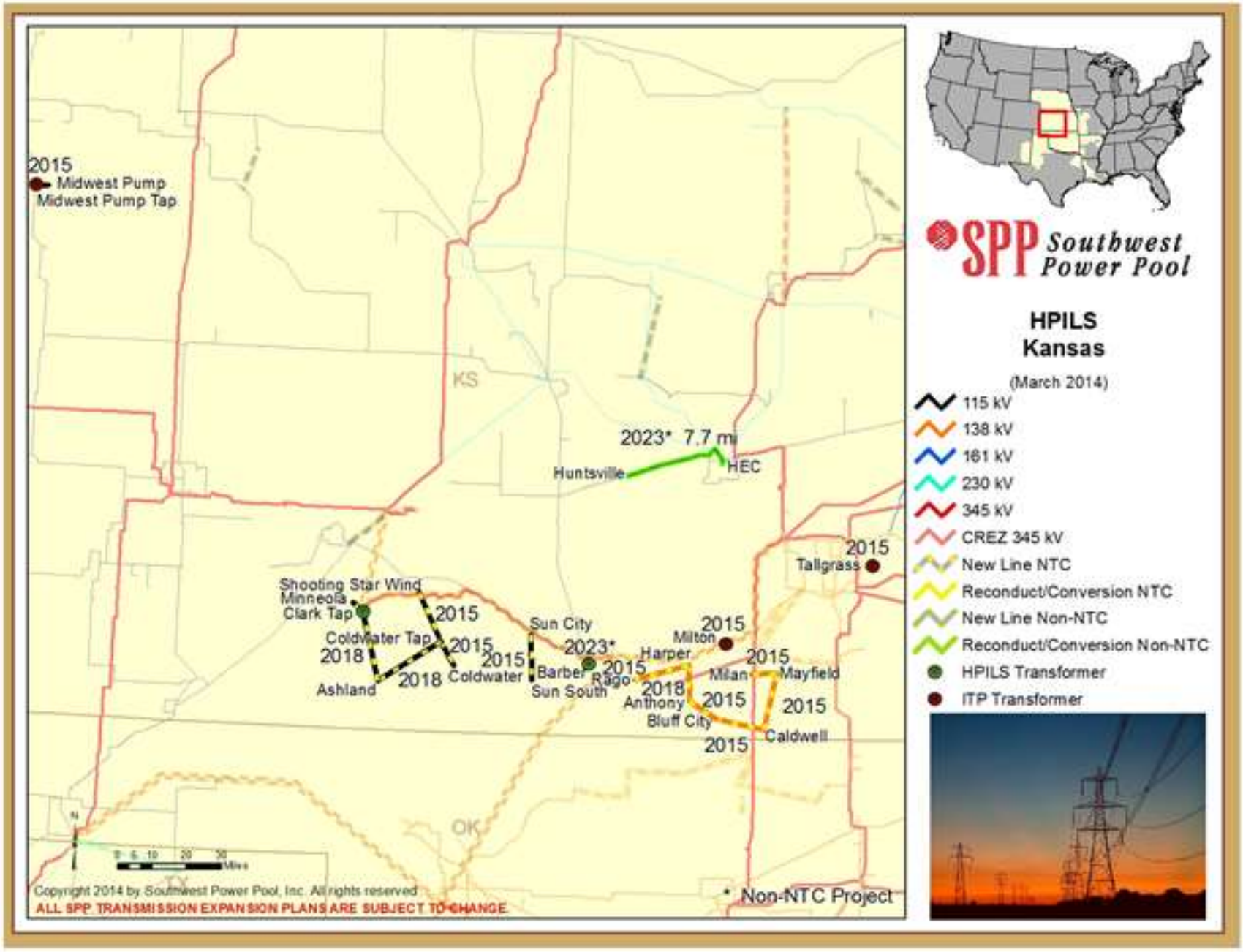
UBS Utilities Global Research

5 December 2013

"Xcel Energy Inc; It's All About Execution"

Incremental Generation




2015
Midwest Pump
Midwest Pump Tap
KS
2023* 7.7 mi
Huntsville
HEC
2015
Tallgrass
Shooting Star Wind
Minneola
Clark Tap
2015
Coldwater Tap
2018
2015
2018
Ashland
Coldwater
2015
Sun City
2023*
Barber
Sun South
2015
Rago
2015
Milton
Harper
2015
Milan
Mayfield
2018
Anthony
2015
2015
Bluff City
Caldwell
2015
OK
0 5 10 20 30
Miles
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ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE
* Non-NTC Project
SPP Southwest Power Pool
HPILS
Kansas
(March 2014)
115 kV
138 kV
161 kV
230 kV
345 kV
CREZ 345 kV
New Line NTC
Reconduct/Conversion NTC
New Line Non-NTC
Reconduct/Conversion Non-NTC
HPILS Transformer
ITP Transformer

SPP Southwest Power Pool

HPILS
Nebraska

(March 2014)

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
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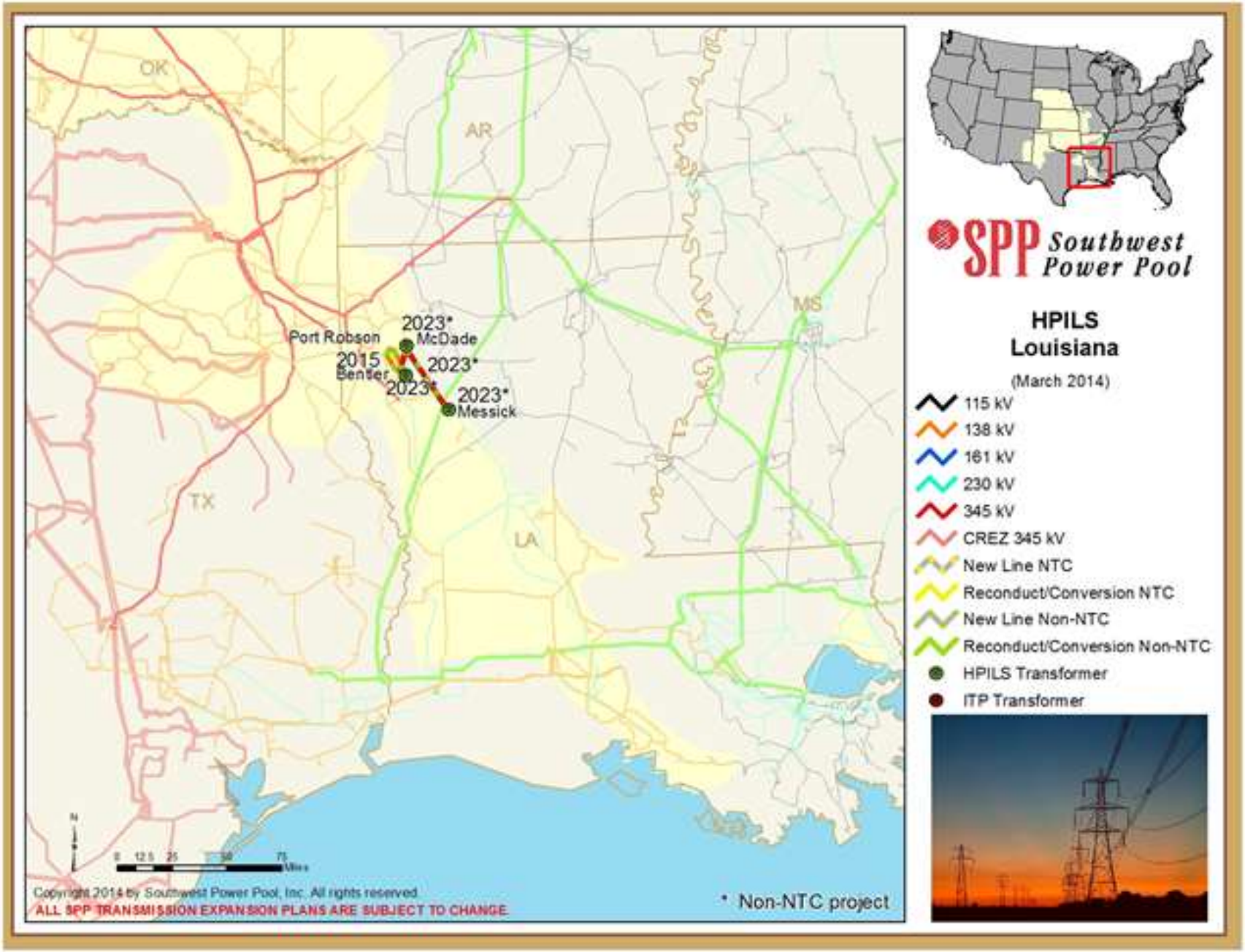
- HPILS Transformer


OK
AR
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LA
Port Robson
2015
Bentler
2023*
McDade
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Messick
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Miles
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* Non-NTC project
SPP Southwest Power Pool
HPILS
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(March 2014)
115 kV
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161 kV
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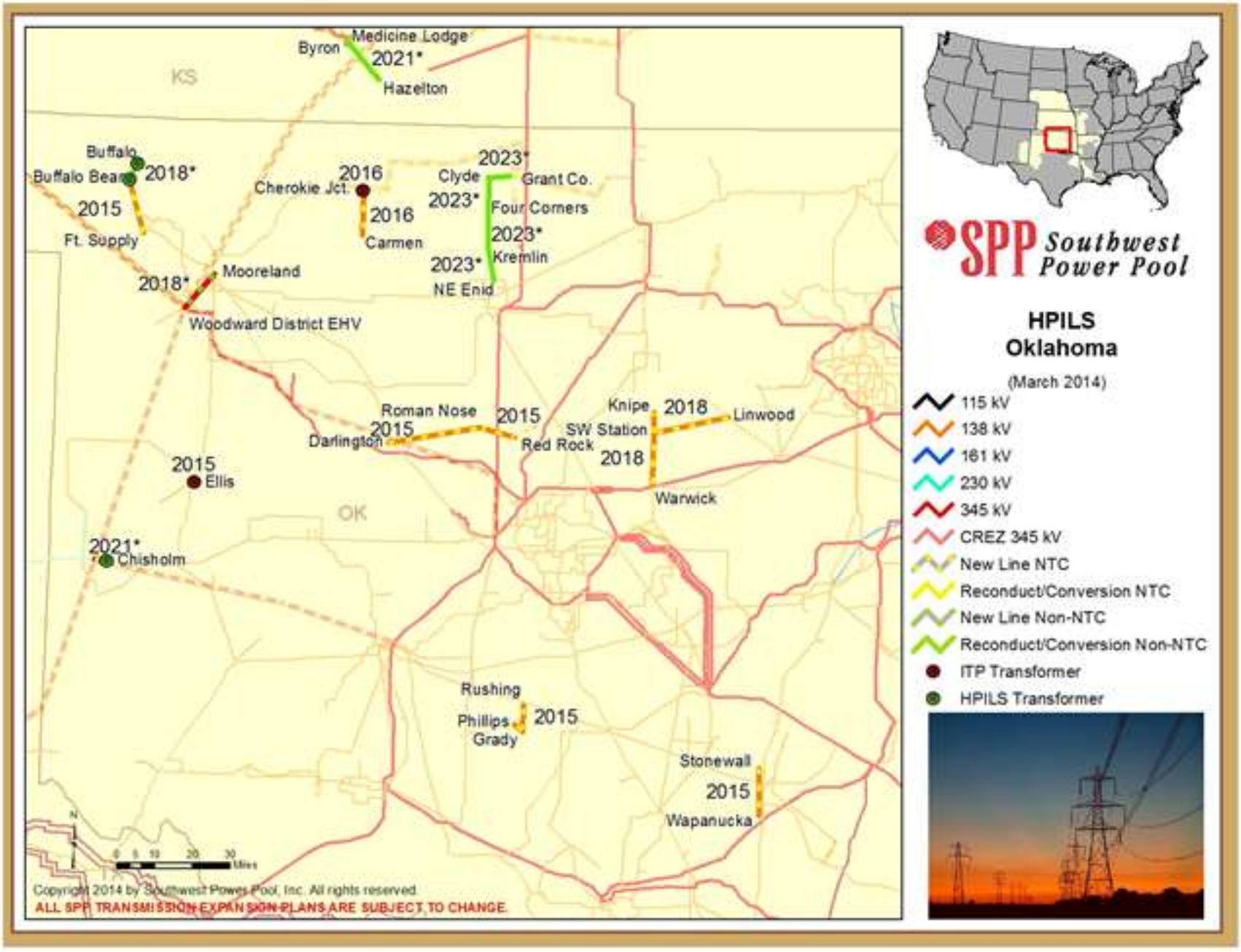
New Line Non-NTC
Reconduct/Conversion Non-NTC
HPILS Transformer
ITP Transformer


Medicine Lodge
Byron
2021*
Hazelton
KS
Buffalo
Buffalo Bear
2018*
2015
Ft. Supply
2016
Cherokie Jct.
2016
Carmen
2023*
Clyde
Grant Co.
2023*
Four Corners
2023*
Kremlin
2023*
NE Enid
2018*
Mooreland
Woodward District EHV
Roman Nose
2015
2015
Darlington
Red Rock
Knipe
2018
SW Station
2018
Linwood
Warwick
2015
Ellis
OK
2021*
Chisholm
Rushing
Phillips
Grady
2015
Stonewall
2015
Wapanucka
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SPP Southwest Power Pool
HPILS
Oklahoma
(March 2014)
115 kV
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New Line NTC
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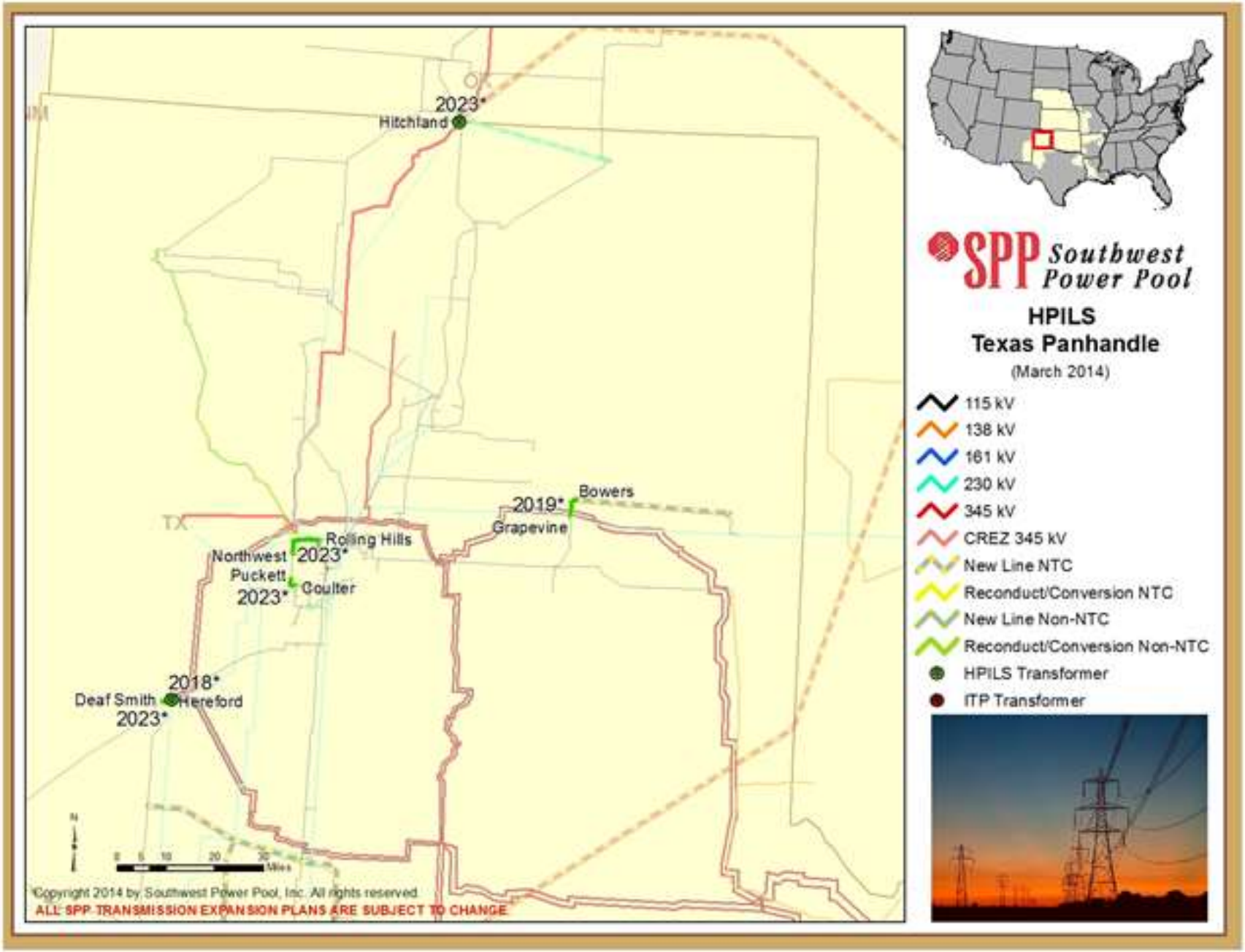
New Line Non-NTC
Reconduct/Conversion Non-NTC
ITP Transformer
HPILS Transformer


2023*
Hitchland
2019*
Bowers
Grapevine
Rolling Hills
Northwest
2023*
Puckett
2023*
Coulter
2018*
Deaf Smith
Hereford
2023*
TX
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SPP Southwest Power Pool
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Texas Panhandle
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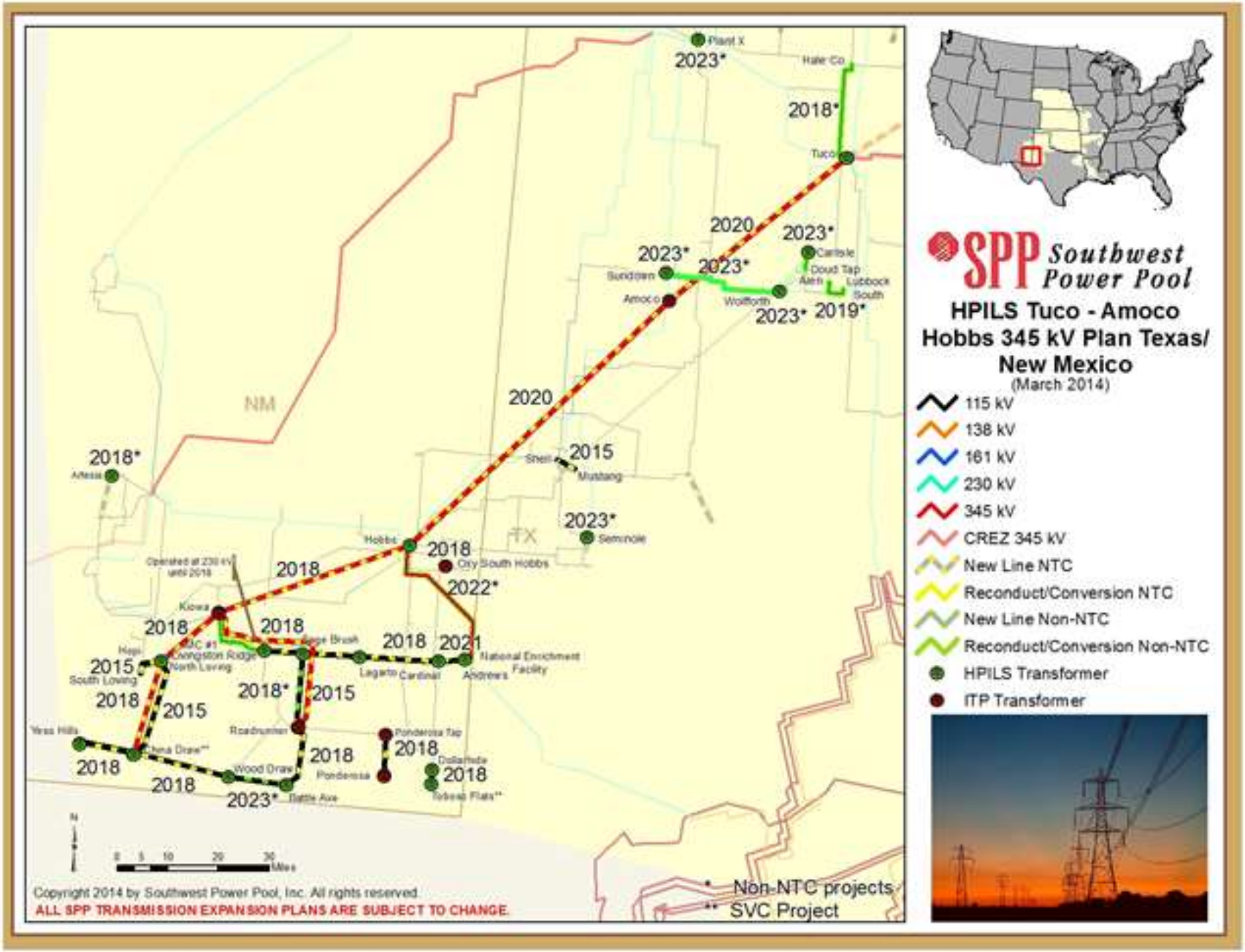
New Line Non-NTC
Reconduct/Conversion Non-NTC
HPILS Transformer
ITP Transformer

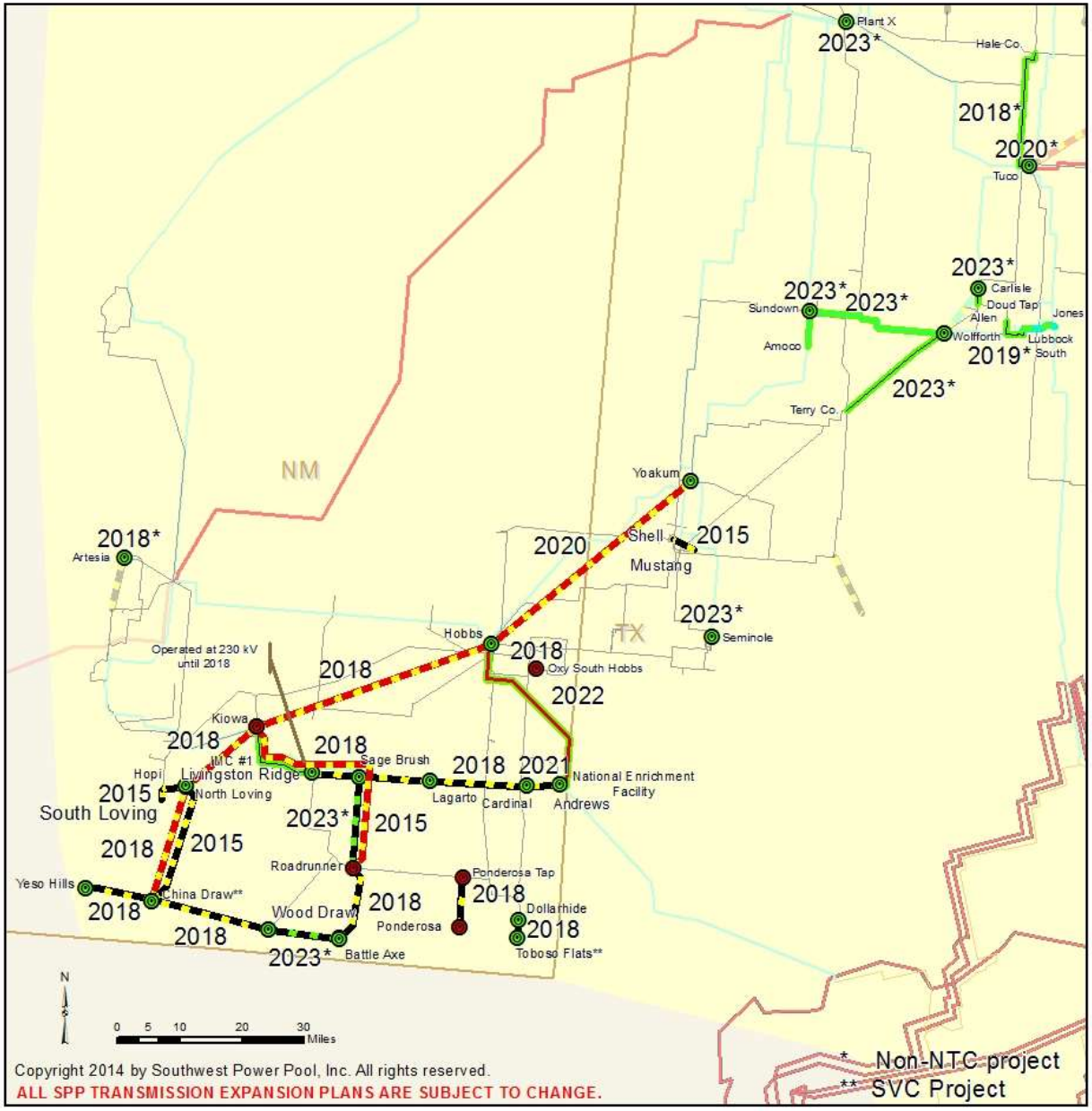


SPP Southwest Power Pool

HPILS Tuco - Amoco Hobbs 345 kV Plan Texas/ New Mexico

(March 2014)

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- CREZ 345 kV
- New Line NTC
- Reconduct/Conversion NTC
- New Line Non-NTC
- Reconduct/Conversion Non-NTC
- HPILS Transformer
- ITP Transformer

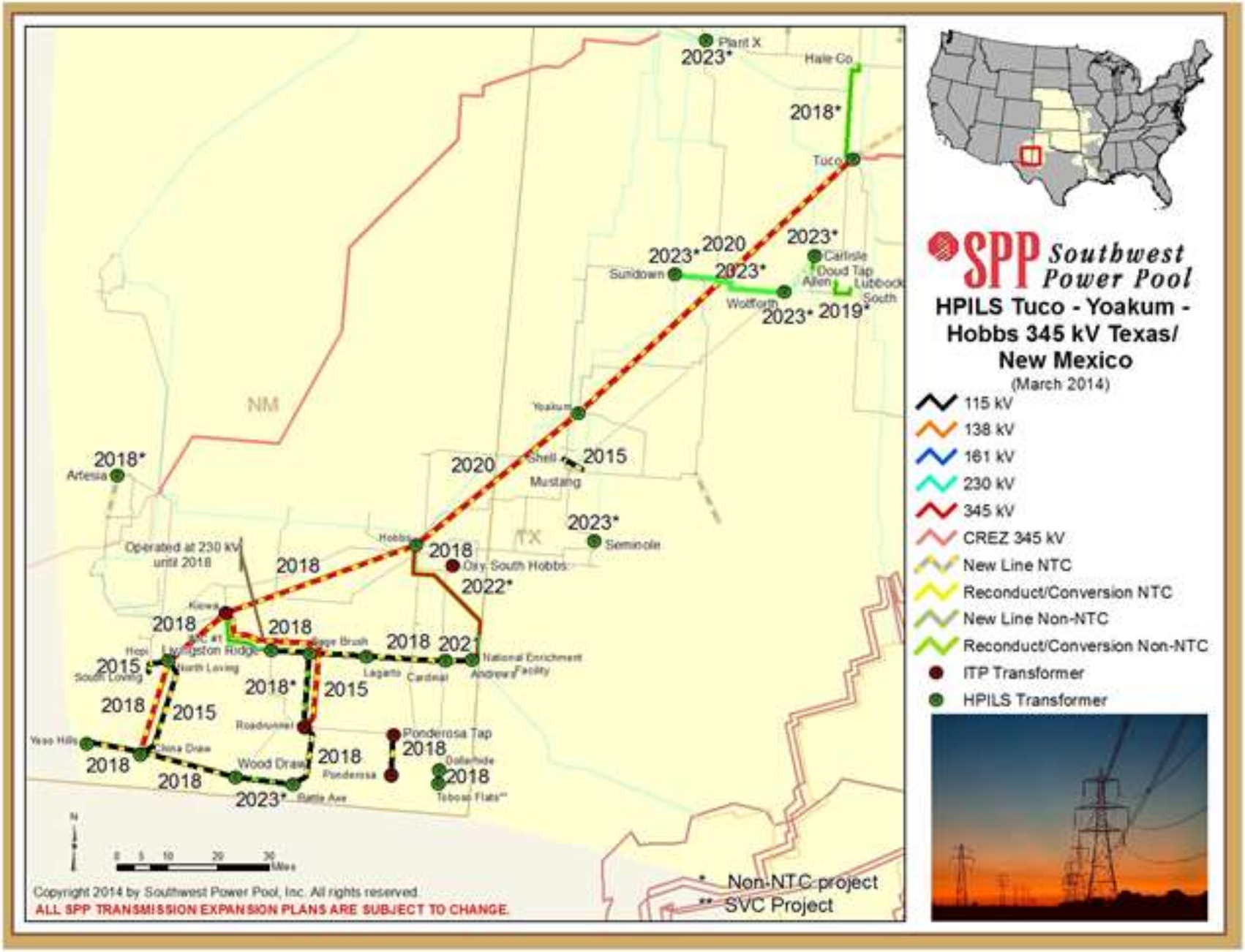


SPP Southwest Power Pool

HPILS Yoakum-Hobbs 345 kV Plan Texas/ New Mexico

(March 2014)

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- CREZ 345 kV
- New Line NTC
- Reconduct/Conversion NTC
- New Line Non-NTC
- Reconduct/Conversion Non-NTC
- ITP Transformer
- HPILS Transformer


Plant X
2023*
Hale Co
2018*
Tuco
2023*
2020
2023*
Carlisle
2023*
Sundown
Doud Tap
Allen
Lubbock South
Wolfforth
2023*
2019*
NM
Yoakum
2018*
Artesia
2020
Shell
2015
Mustang
2023*
Hobbs
TX
Seminole
Operated at 230 kV until 2018
2018
2018
Oxy South Hobbs
2022*
Kiowa
2018
2018
Hopi
Livingston Ridge
Sage Brush
2018
2021
National Enrichment Facility
2015
South Loving
North Loving
Lagarto
Cardinal
Andrews
2018*
2015
2018
2015
Roadrunner
Ponderosa Tap
Yoso Hills
2018
China Draw
2018
Wood Draw
2018
Ponderosa
Dollarhide
2018
2018
2023*
Battle Axe
Tobosa Flats**
0 5 10 20 30 Miles
Copyright 2014 by Southwest Power Pool, Inc. All rights reserved.
ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE.
* Non-NTC project
** SVC Project
SPP Southwest Power Pool
HPILS Tuco - Yoakum - Hobbs 345 kV Texas/ New Mexico
(March 2014)
115 kV
138 kV
161 kV
230 kV
345 kV
CREZ 345 kV
New Line NTC
Reconduct/Conversion NTC
New Line Non-NTC
Reconduct/Conversion Non-NTC
ITP Transformer
HPILS Transformer

Initial

SPP Southwest Power Pool

HPILS 345 kV
Conceptual Expansion
Texas/NewMexico
(April 2014)

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- CREZ 345 kV
- New Line NTC
- Reconduct/Conversion NTC
- New Line Non-NTC
- Reconduct/Conversion Non-NTC
- ITP Transformer
- HPILS Transformer

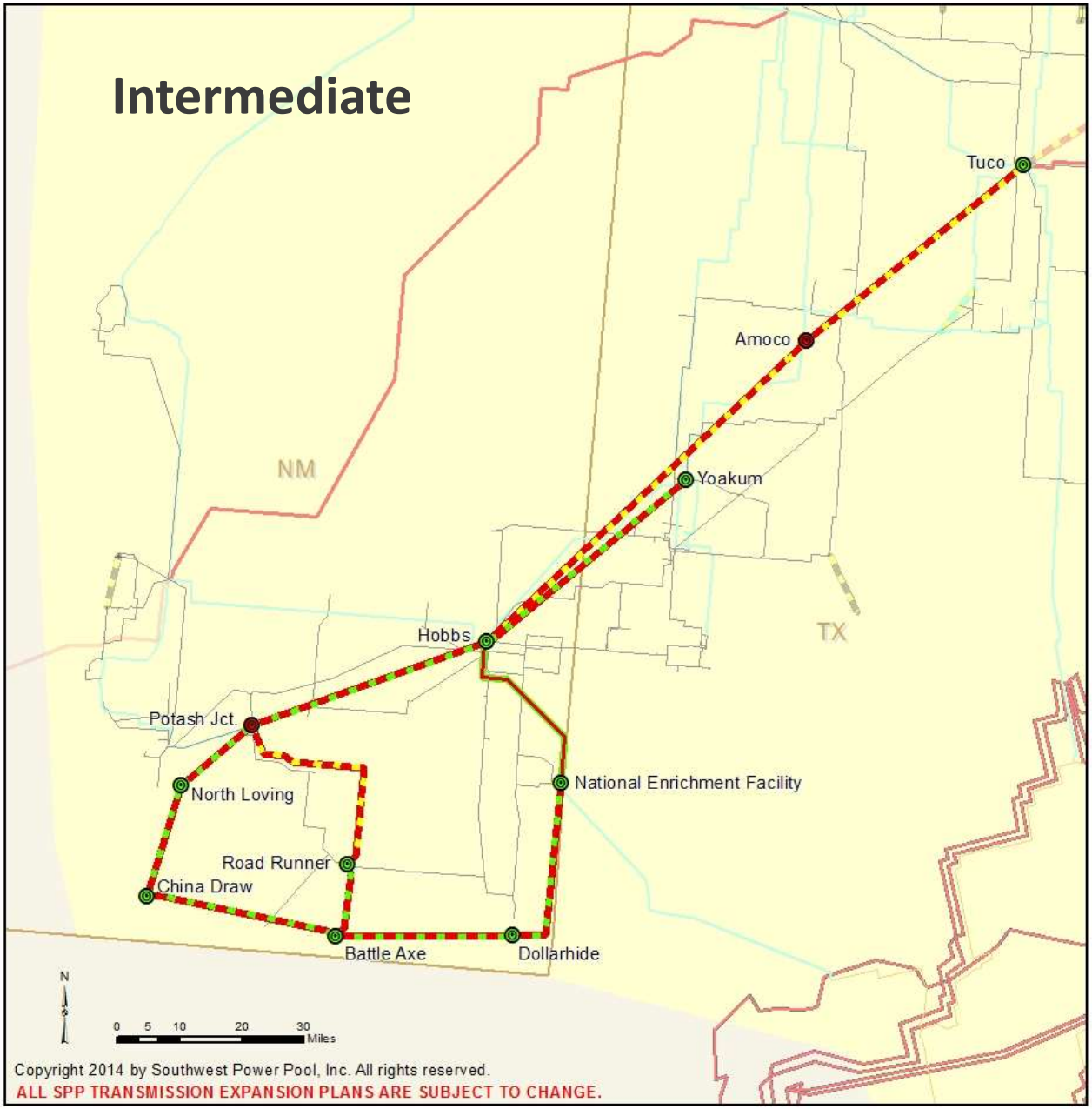
Tuco
Amoco
NM
TX
Hobbs
Potash Jct.
National Enrichment Facility
Road Runner
4
China Draw
Battle Axe
5

N

0 5 10 20 30 Miles

ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE.

Intermediate



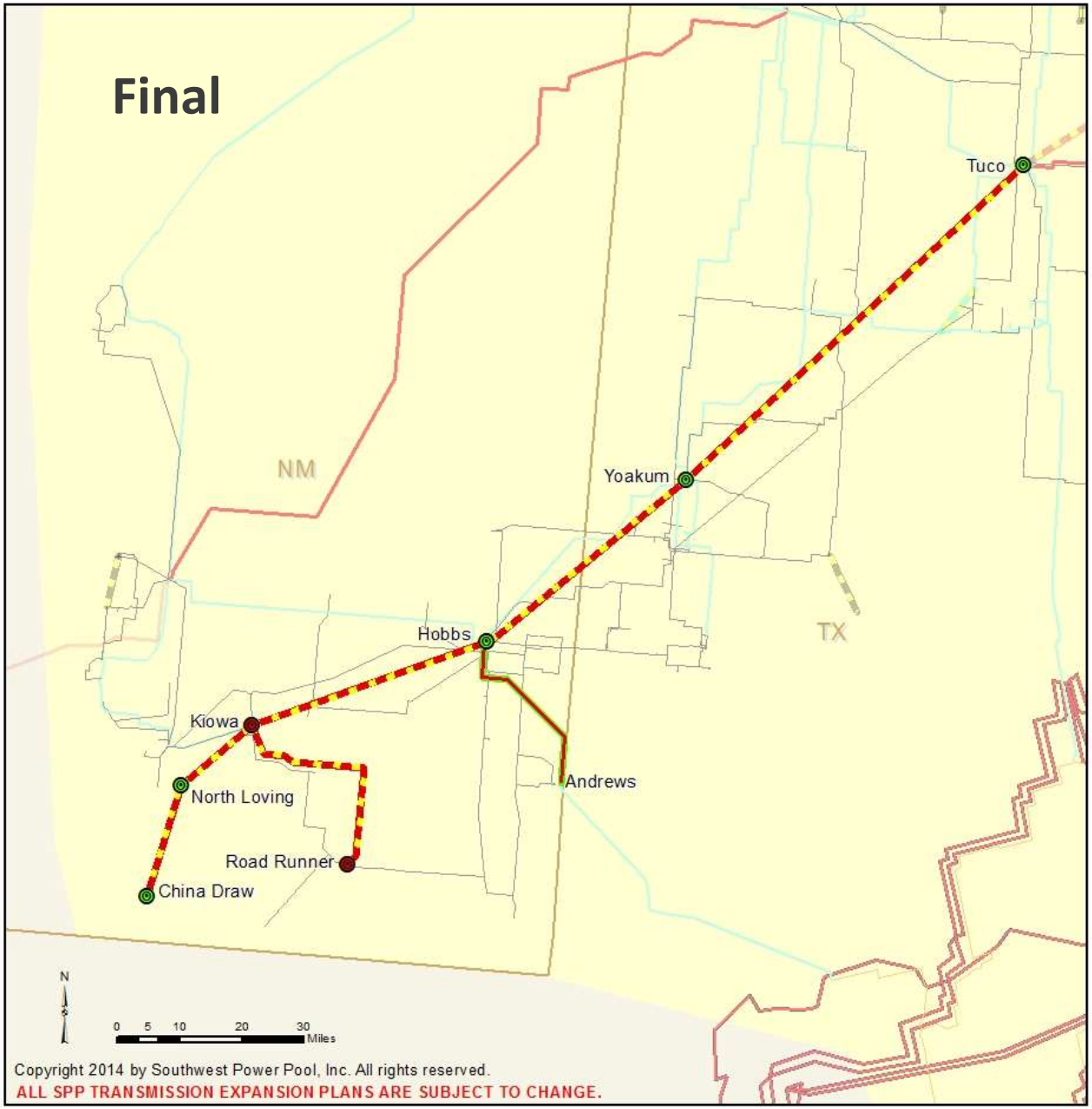
SPP Southwest Power Pool

HPILS 345kV Intermediate Expansion Plan
Texas/NewMexico
(April 2014)

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- CREZ 345 kV
- New Line NTC
- Reconduct/Conversion NTC
- New Line Non-NTC
- Reconduct/Conversion Non-NTC
- ITP Transformer
- HPILS Transformer

ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE.

Final



SPP Southwest Power Pool

HPILS 345 kV
Proposed Expansion
Texas/NewMexico
(April 2014)

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- CREZ 345 kV
- New Line NTC
- Reconduct/Conversion NTC
- New Line Non-NTC
- Reconduct/Conversion Non-NTC
- ITP Transformer
- HPILS Transformer

ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE.

Economic Analysis

- Economic Needs Assessment based on scope and leveraged ITP10 assumptions
- Economic Needs Assessment did not identify opportunities for economic projects to be considered as part of the HPILS Portfolio
- HPILS TF decided to limit HPILS economic analyses given findings, practical considerations of timing, resources limitations and pending ITP10 analyses

2023 50/50 Incremental Reliability Portfolio APC Delta

SPP Footprint Summary			
Adjusted Production Cost Delta (2023$, Millions)			
Base Case Comparison to Incremental Reliability Portfolio without West TX/NM Alternatives			
SPP TS Customers Benefits	$ (152.0)		
SPP Other Benefits (SWPA)	$ 0.4		
TOTAL (TS Customers + Other)	$ (151.6)		
Base Case Comparison to Reliability Portfolio with West TX/NM Alternatives			
	TAH	YH	TYH
SPP TS Customers Benefits	$ (163.6)	$ (137.5)	$ (167.6)
SPP Other Benefits (SWPA)	$ (0.3)	$ (0.1)	$ (0.3)
TOTAL (TS Customers + Other)	$ (164.0)	$ (137.5)	$ (167.9)
Regional[1] SPP TSC APC Delta Breakdown (2023$, Millions)			
AR	$ (0.2)	$ 1.0	$ 0.1
KS	$ (9.4)	$ (9.6)	$ (9.1)
LA	$ -	$ (0.2)	$ -
MO	$ (2.1)	$ (2.4)	$ (1.6)
NE	$ 2.7	$ 0.7	$ 1.3
NM	$ (38.0)	$ (24.5)	$ (40.2)
OK	$ (0.8)	$ (5.6)	$ (2.3)
TX	$ (113.1)	$ (100.5)	$ (113.6)

[1] Exclude SPP IPP entities

2023 50/50 TYH Incremental Reliability Portfolio APC Delta Zonal Breakdown

Zonal SPP TSC APC Delta Breakdown (2023$, Millions)		
Zone	APC	
AEPW	$	0.4
EMDE	$	(0.2)
GMO	$	0.8
GRDA	$	0.1
KCPL	$	(3.3)
LES	$	0.0
MIDW	$	(2.6)
MKEC	$	(1.5)
NPPD	$	1.2
OKGE	$	0.9
OPPD	$	0.1
SPCIUT	$	(0.6)
SUNC	$	3.1
SWPS	$	(155.6)
WFEC	$	(1.4)
WRI	$	(6.4)
Total	$	(165.1)

2023 50/50 Inferred B/C of TY

SPP Footprint Summary	YH'	TYH	TY
Adjusted Production Cost Delta (2023$, Millions)			
SPP TS Customers Benefits	$ 17.4	$ (15.6)	$ (33.0)
SPP Other Benefits (SWPA)	$ (0.6)	$ (0.8)	$ (0.2)
TOTAL (TS Customers + Other)	$ 16.8	$ (16.3)	$ (33.1)
Project Cost (2023$, Millions)			
1 Yr. Project Cost	$ 15.5	$ 48.0	$ 32.5
Benefit / Cost Ratio Summary			
SPP TS Customers Benefits	(1.12)	0.33	1.02
SPP Other Benefits (SWPA)	0.04	0.02	0.01
TOTAL (TS Customers + Other)	(1.08)	0.34	1.02

TYH Incremental Benefits

	2020*	2023
Incremental Benefit	$6.8	$16.3

*2020 values interpolated from 2018 and 2023 data points

- One-Year APC Savings for SPP Resulting from TYH ($ millions)
- Two study years were analyzed, 2018 and 2023, and the incremental APC savings were calculated consistent with ITP approaches
- 8% discount rate, 2.5% escalation rate, and 20 year terminal value
- Sum of all discounted benefits are presented as the Net Present Value (NPV) benefit

40 Year NPV Value of TYH based on APC

Zone	NPV APC Delta
AEPW	$37.2
EMDE	($0.5)
GMO	$5.9
GRDA	$8.1
KCPL	$2.8
LES	$1.9
MIDW	($13.6)
MKEC	$13.6
NPPD	$0.9
OKGE	$74.0
OPPD	$5.0
SPCIUT	($17.6)
SUNC	($4.4)
SWPS	($533.4)
WFEC	($6.9)
WRI	$17.9
Total	($409.1)

State	NPV APC Delta ($Millions)
Arkansas	$14.9
Kansas	$10.2
Louisiana	$3.5
Missouri	($6.2)
Nebraska	$7.8
New Mexico	($400.4)
Oklahoma	$96.0
Texas	($135.1)
Total	($409.1)

Direct Assigned Facilities

- The following facilities have been designated by TO as direct assigned or radial facilities that would not be Base Plan funded via an NTC as a result of HPILS:
  - MIDW - Midwest Pump
  - WERE – Tallgrass
  - SUNF – Sun City
  - SPS – Yeso Hills, Battle Axe, Toboso Flats, Ponderosa, Oxy South
- These facilities amount to $72M of projects which may be eligible for cost recovery under zonal, but not regional, rates in SPP

HPILS Impact on STEP

Project Category	Cost Estimate
New NTC Projects	$573 M
Withdrawal of Suspended NTC-C for Tuco - New Deal	($57 M)
Withdrawal of Suspended NTC-C for Grassland - Wolfforth	($57 M)
Modification of Suspended NTC-C for Tuco-Amoco-Hobbs	($258 M)
Reinstate NTC-C for Tuco-Yoakum-Hobbs	$238 M
HPILS Impact on STEP	$439 M

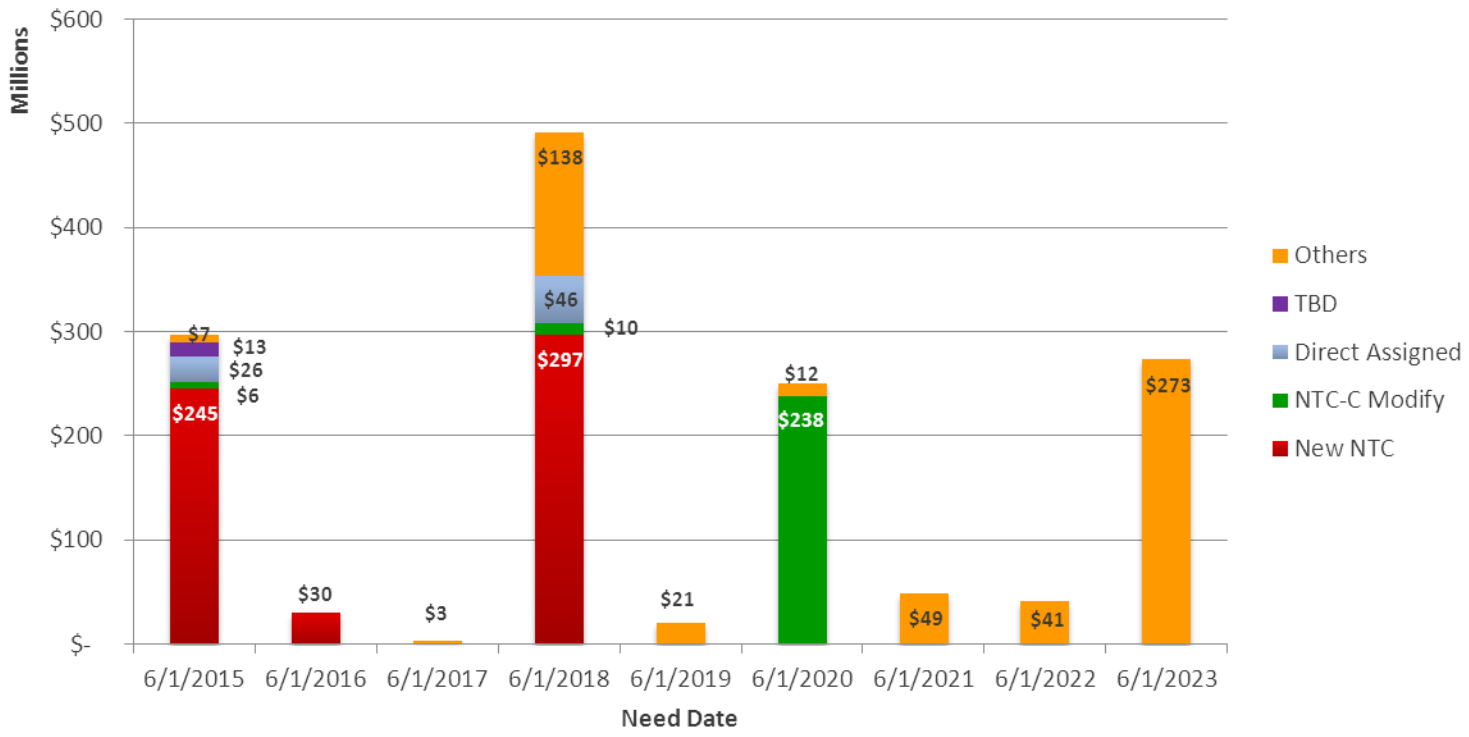
E&C Costs (2014$), which assume new NTCs are Base Plan Funded and does not consider impacts of Direct Assigned Projects

Note that Rate Impacts analysis is conservative in assuming all Direct Assigned Projects (and TBD too) are included in zonal SPP Transmission Rates

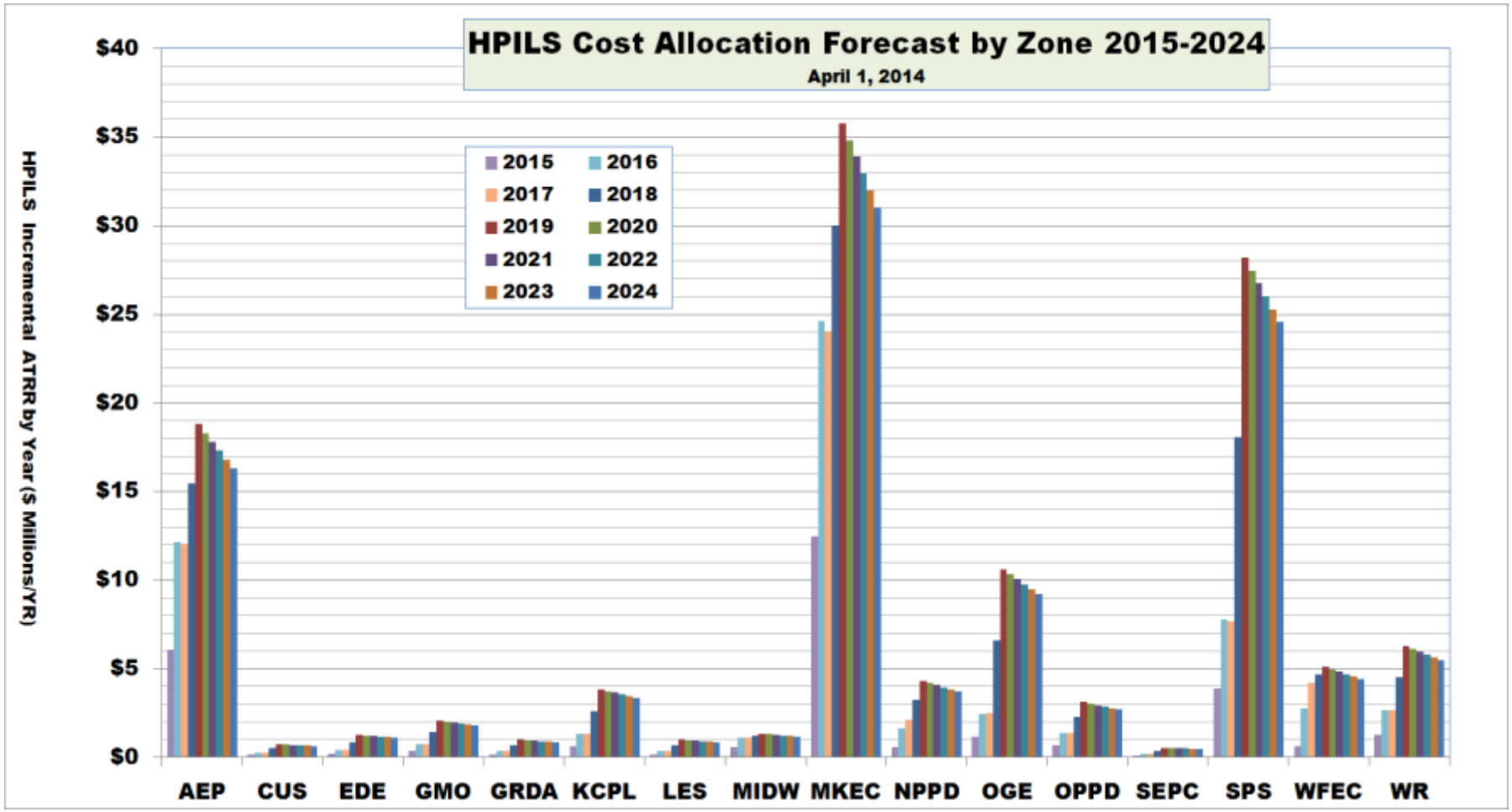
HPILS Portfolio Costs by Need Year

Need Year	New NTC	NTC-C Modify	Direct Assigned	TBD	Others	Total
2015	245	6	26	13	7	296
2016	30					30
2017					3	3
2018	297	10	46		138	491
2019					21	21
2020		238			12	250
2021					49	49
2022					41	41
2023					273	273
Total	**573**	**253**	**72**	**13**	**544**	**1,455**

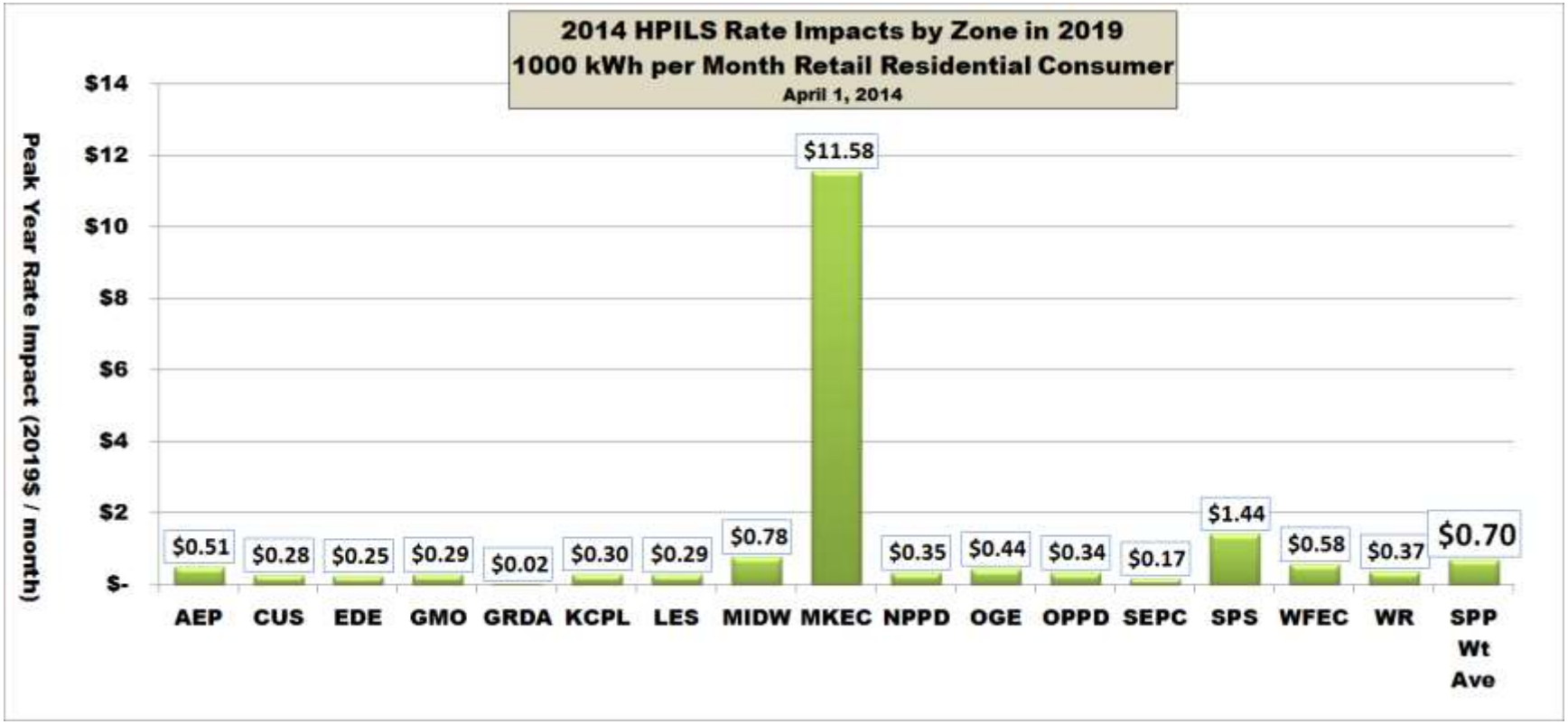
HPILS Portfolio Costs by Need Year



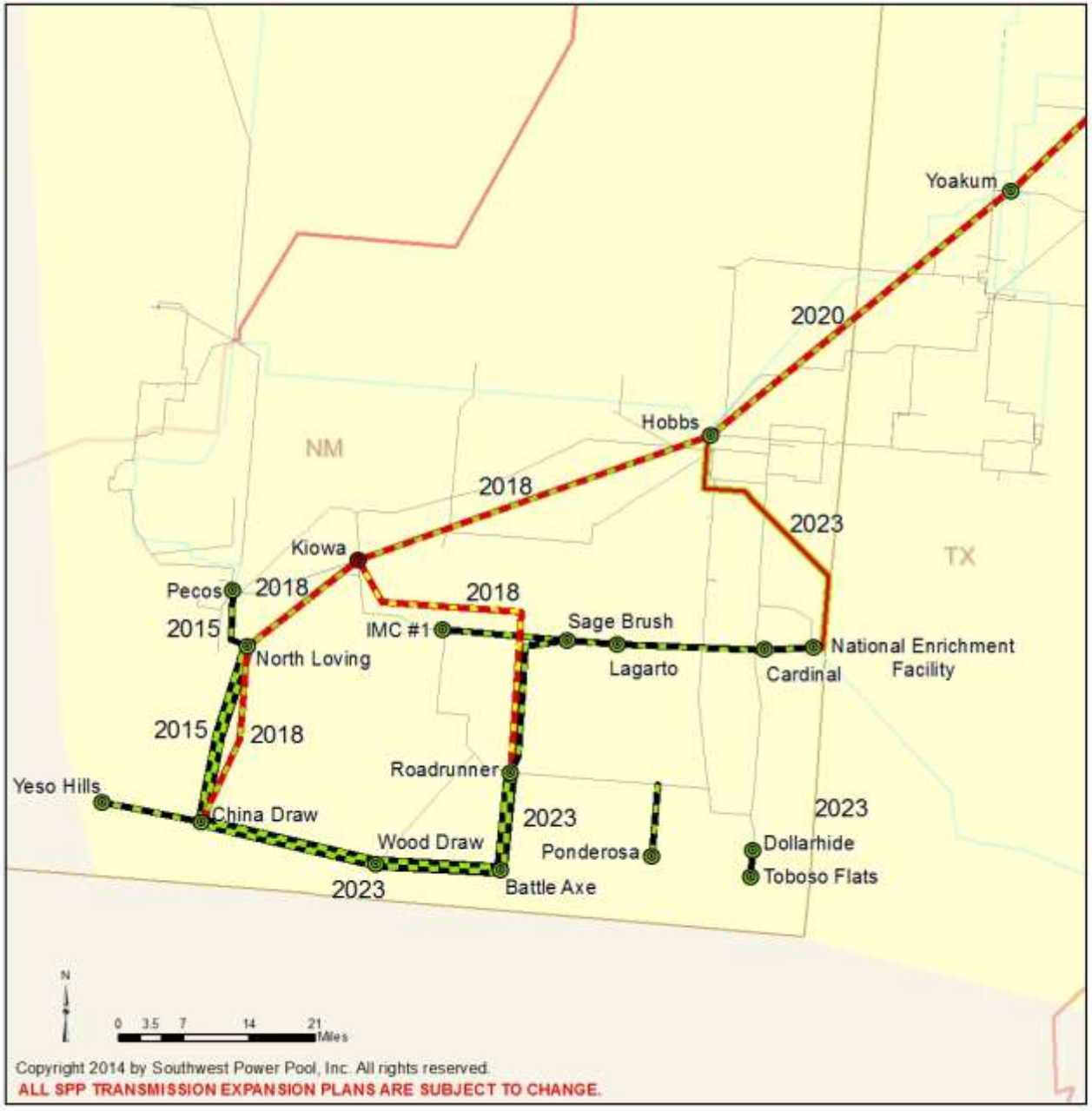
ATRR Allocations from Incremental HPILS Upgrades



Projected HPILS Incremental Rate Impacts



NOTE: Rate impacts assume $85M of Direct Assigned and TBD projects are allocated to host zonal transmission rate



ALL SPP TRANSMISSION EXPANSION PLANS ARE SUBJECT TO CHANGE.

SPP Southwest Power Pool

HPILS Yoakum - Hobbs 345 kV Plan

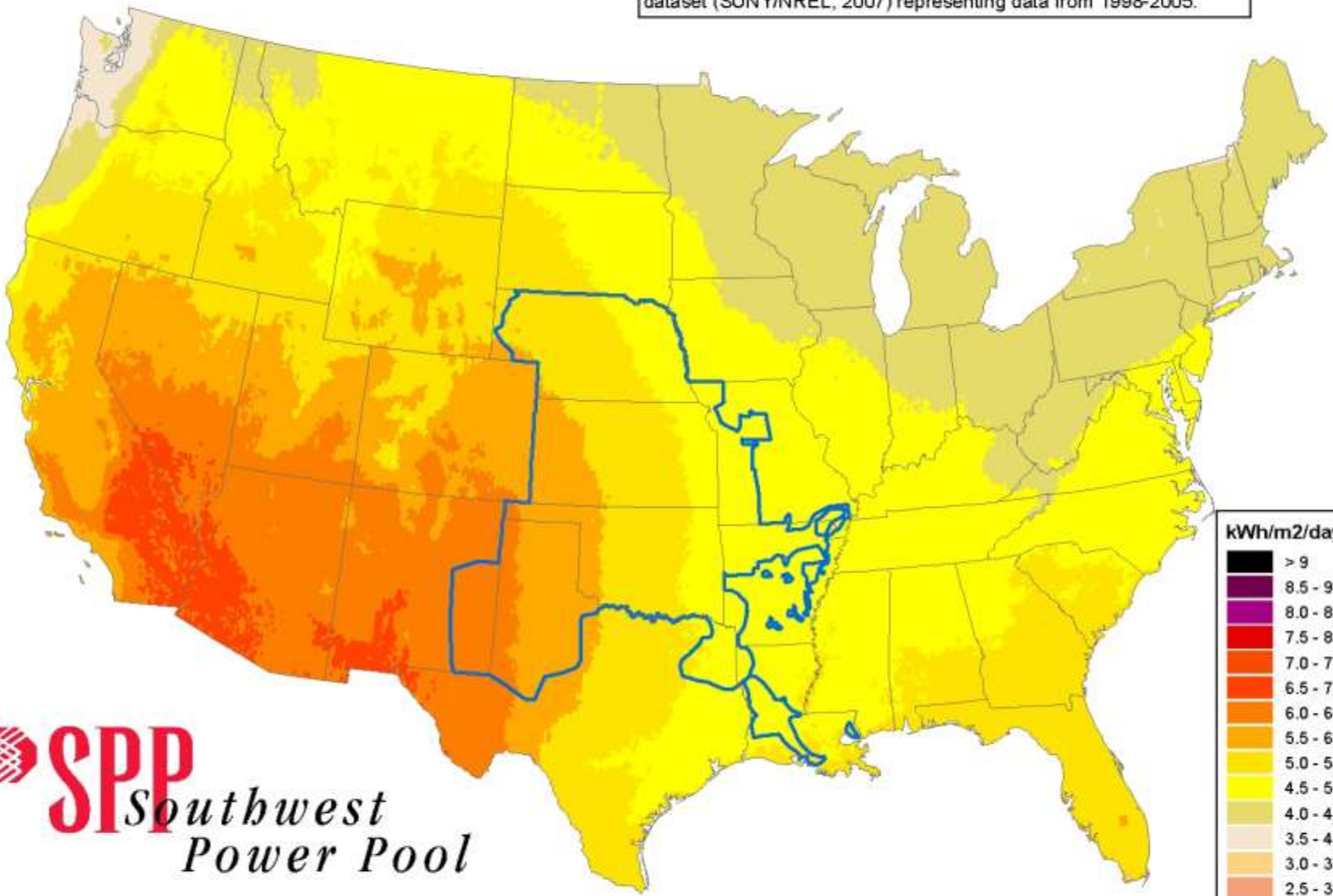
(February 2014)

- HPILS, 115
- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- New Line ITP
- Reconduct/Conversion ITP
- New Line HPILS
- Reconduct/Conversion HPIL
- ITP Transformer
- HPILS Transformer

PV Solar Radiation
(Flat Plate, Facing South, Latitude Tilt)

Annual

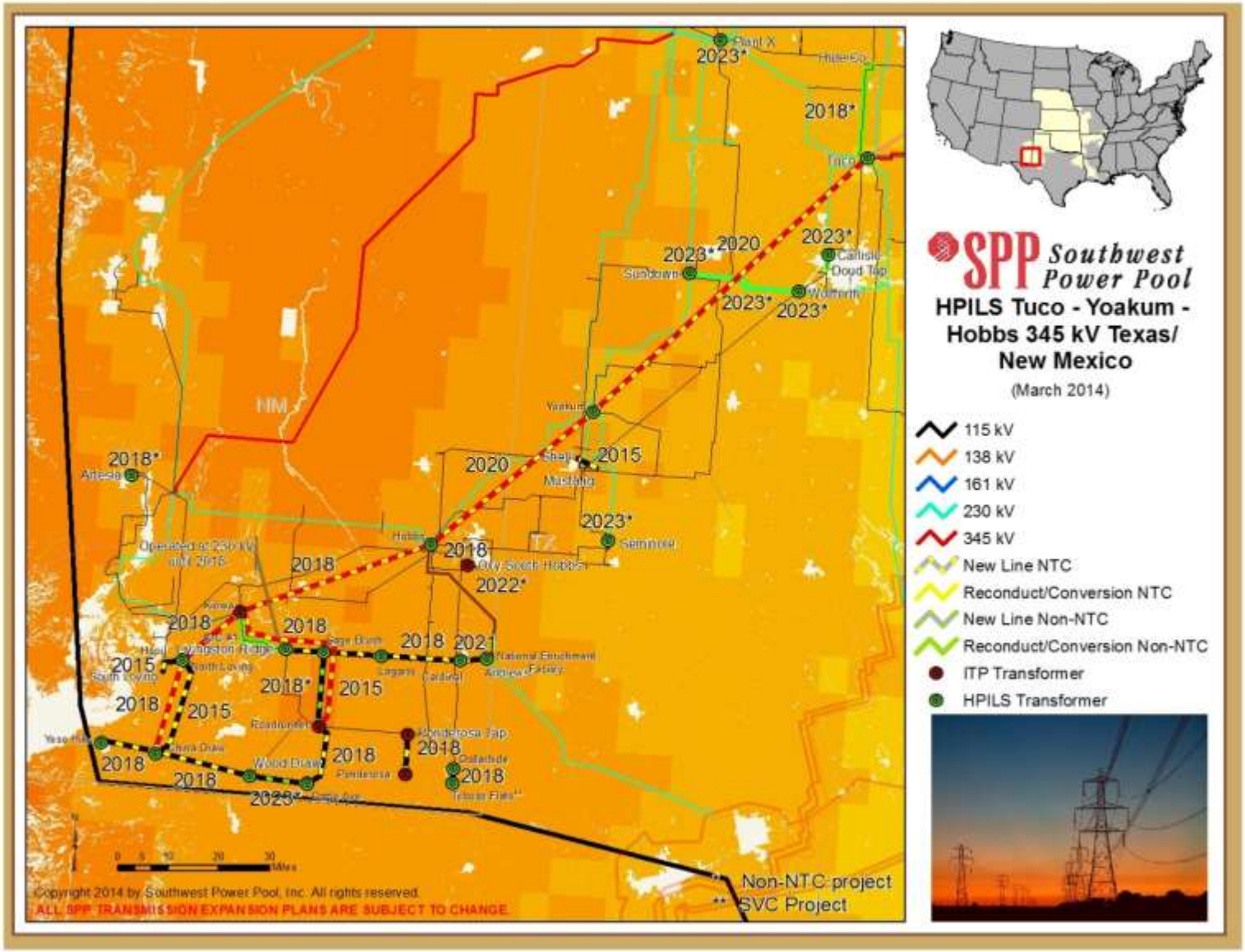
This data represents annual average solar resource potential for 48 Contiguous United States and Hawaii, in High Resolution. The data for Hawaii and the 48 contiguous states is a 10 km, satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2005.



SPP Southwest Power Pool

Source: National Renewable Energy Laboratory (NREL), U.S. Department of Energy

HPILS Enables Best Solar Development in EI



Conclusions

- HPILS TF has completed its assignment per the approved scope and identified a cost effective solution set to address N-1 reliability needs through 2023
- Several HPILS Portfolio Projects need commitments prior to next ITP study based on need dates and lead times, and criteria approved by HPILS TF and TWG
- HPILS does not bypass existing tariff processes, but compliments them per the BOD directive
- The suspended NTC-C for Tuco-Amoco-Hobbs is a reliability solution in 2020, but should be modified to Tuco-Yoakum-Hobbs to save significant costs and achieve better performance

DPP Analysis

April 10th, 2014

SPP Southwest Power Pool

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Background

- Required by FERC Order 1000
- Removes federal right of first refusal (ROFR) for the construction of transmission projects from regional tariffs
- SPP will bid out approved transmission projects to qualified participants using the Transmission Owner Selection Process (TOSP)

Pre-Project Selection

- SPP staff shall notify stakeholders of the identified transmission needs
- A transmission planning response window of thirty (30) days
- The information in the DPP must be sufficient to allow SPP staff to evaluate the project

SELECTION PROCESS

Phase 1 – Individual Project Testing

- Projects will move on to Phase 2 for further testing if they meet the following criteria
  - The project must meet the need for which it was submitted and
    - Projects to address economic needs must provide a 1-year B/C ratio greater than 0.9 by reducing the congestion. If the project is a seams project the B/C ratio requirement is .8
    - Policy Projects must allow the utilities to meet the regulatory/statutory mandates and goals. Competing projects will be tested for net APC benefit

Phase 2 – Project Grouping

- Project groupings with the greatest Net APC benefit will move on to the final portfolio per future
- Reliability, policy, and economic projects will be combined into project groupings for each future
- The grouping of projects will be evaluated for redundancies

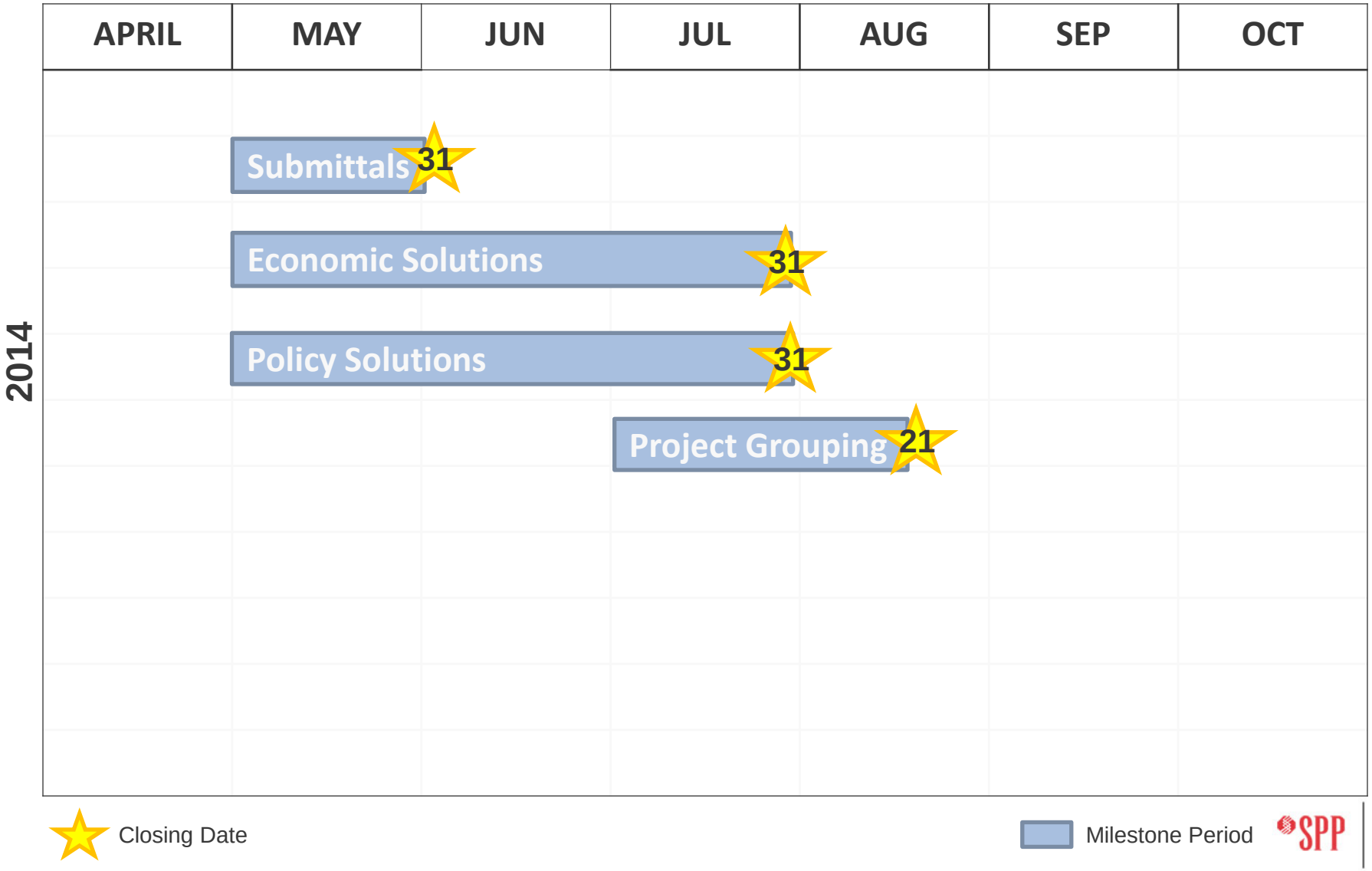
Phase 3 – The Consolidated Portfolio

- The consolidation will be consistent with the Stakeholder approved consolidation methodology

Post Project Selection

- If the project described in a DPP is selected and approved for construction as a Competitive Upgrade, the submitting stakeholder may be eligible to receive incentive points in the bidding process

Timeline


APRIL
MAY
JUN
JUL
AUG
SEP
OCT
2014
Submittals
31
Economic Solutions
31
Policy Solutions
31
Project Grouping
21
Closing Date
Milestone Period

Economic Assessment Areas

April 10th, 2014

SPP Southwest Power Pool

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Background

- System congestion will be identified in each of the 8,784 hours.
- A list of binding constraints will be developed for each future and ranked based upon the average shadow price associated with each constraint.
- The top twenty constraints based upon this ranking will be identified as economic needs

Constraint List Options

- Top 20 constraints:
  - SPP Area only
  - SPP + Integrated System
  - SPP + Integrated System + Seams
- Top 20 constraints in the SPP area plus 5 top in the Integrated System
- Top 20 constraints in the SPP area plus 5 top in the Integrated System plus 5 top in the Seams

Recommendation

- **SPP Staff, recommends to use up to the top 20 constraints in the SPP area plus up to the 2 top in the Integrated System plus up to the 8 top in the Seams**

Policy Needs Assessment

ESWG

April 10th, 2014

SPP Southwest Power Pool

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Policy Needs Definition

- A policy need results when a company is unable to meet a renewable mandate/goal due to inadequate transmission to deliver wind
  - Results in wind curtailment in the SCUC/SCED simulation
- Transmission projects will be developed to address policy needs

Renewable Energy Standards by State

State	Type	Source	Amount
Arkansas	Court Order	United States District Court Order (SWEPCO)	400 MW in SWEPCO Service Territory (AR, LA, or TX)
Kansas	Statute	Kansas Statutes 66-1256 - 66-1262	10% - 2011 - 2015 15% - 2016 - 2019 20% - 2020
Louisiana	Court Order	United States District Court Order (SWEPCO)	400 MW in SWEPCO Service Territory (AR, LA, or TX)
Missouri	Statute	R.S. Mo. § 393.1020 et seq.	2% - 2011 - 2013 5% - 2014 - 2017 10% - 2018 - 2020 15% - 2021
Nebraska	State Agency	Public Power District Board Action	10% - 2020 (NPPD/OPPD)
New Mexico	Statute	Renewable Energy Act ("REA"), §§ 62-16-1 et seq. NMSA	10% - Current 15% - 2015 20% - 2020
Oklahoma	Statute	17 Okl. St. § 801.4	15% by 2015
Texas	Statute	TEX UT. CODE ANN. § 39.904 United States District Court Order (SWEPCO)	5,256 MW - Current 5,880 MW – 2015 400 MW in SWEPCO Service Territory (AR, LA, or TX)

Policy Needs Identification

- After SCUC/SCED simulation, renewable output will be analyzed by company, by state, to determine how much wind energy is being delivered vs. curtailed.
  - Wind from the OTHER category of Policy Survey does not qualify towards policy needs
  - Companies with annual wind energy output less than 97% of the scheduled energy output will be identified as having policy need(s)

Example 1

- Company A is subject to state renewable <u>capacity</u> mandate/goal of 150 MW
  - 150 MW (500,000 MWh) of installed wind driven by mandate/goal
    - Company must deliver 500,000 MWh * 0.97 = 485,000 MWh
  - 60 MW (200,000 MWh) of additional installed wind classified as OTHER
  - All 700,000 MWh of wind is available to meet required 485,000 MWh threshold

Example 2

- Company B is subject to renewable capacity mandate/goal of 55 MW in state X
  - 100 MW (400,000 MWh) of installed wind in state X assigned to company B
- Company B is subject to renewable energy mandate/goal of 1,000,000 MWh in state Y
  - 300 MW (1,000,000 MWh) of installed wind in state Y assigned to company B
- Company B must deliver (55 MW)*(CF)*(8,784 hrs)*(97%) to meet state X mandate/goal
- Any additional wind not needed to meet state X goal can be applied toward state Y goal

Next Steps

- Staff is working to assess specific requirements for each company, for each state, based on data from Policy Survey
- Analyze wind curtailments from model and identify companies that do not meet renewable mandates/goals

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 24th, 2014

Web Conference

• SUMMARY OF ACTIONS TAKEN •

1. SPP Staff will develop a methodology to select Economic Needs.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 24th, 2014

Web Conference

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains, LLC) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:35 a.m., welcomed those in attendance. (Attachment 1 – Attendance List)

There were 46 web conference participants representing 10 of 11 members.

Agenda Item 1b – Receipt of Proxies

Juliano Freitas (SPP staff) requested proxy statements. No proxies identified.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains, LLC) presented the agenda for review and asked for any additions or corrections. The agenda was approved unanimously. (Attachment 2 – Agenda)

> **A motion to approve the proposed agenda was made by Kurt Stradley (LES) and seconded by Paul Dietz (Westar). The motion was approved unanimously.**

After approving the agenda Juliano Freitas (SPP Staff) asked members if they decided to approve the methodology proposed by SPP Staff to select Economic Needs (For further details check the April 10, 2014 Minutes). Members did not have a final decision and asked SPP to develop a methodology to calculate the benefit of adding these needs in the 2015 ITP10 Study. Members decided to make a motion to approve the methodology that will be developed by SPP Staff, due to a limited amount of time to have the ESWG vote before the next face to face meeting. SPP Staff will post the methodology as soon as possible.

> **A motion to approve the methodology to select economic needs to be developed by SPP Staff was made by Leon Howell (OGE) and seconded by Kurt Stradley (LES). The motion was approved unanimously.**

ACTION ITEM: SPP Staff will develop a methodology to select Economic Needs.

Agenda Item 2 – Metrics Review

Antoine Lucas (SPP staff) continued presenting the metrics review, the focus of his presentation in this particular web conference is on metrics that have received more attention from stakeholders during the ITP process and also in the previous RCAR. The main metrics approached in the presentations were: Assumed Benefit of Mandated Reliability Projects, Public Policy Benefits, Mitigation of Transmission Outages, Increased Wheeling Through and Out Benefits and Marginal Energy Losses Benefit. For each metric Antoine explained the methodology options currently under evaluation to calculate these metrics and allocate benefits. ESWG members asked for more time to review the methods proposed before having a final decision. (Attachment 3 – Metrics Review)

Agenda Item 3 – DPP – Projects Selection Methodology

Juliano Freitas (SPP staff) presented the methodology developed by SPP Staff to select economic and policy projects to be included in the final 2015 ITP10 portfolio. The process consists of three phases; the intention is to select the optimal projects in order to have a robust transmission plan. In Phase one, projects will be evaluated on an individual basis, with the selection being made considering the economic and/or policy performance of each project. In phase two, the projects performance will be measured as part of a grouped portfolio, evaluating first the reliability projects, and then on top of that policy projects, and finally the last group to be added will be the economic projects. Phase three consists of a consolidation methodology combining the final groupings from both futures. The DPP project submittal window will begin after assessments are complete. ESWG members requested SPP Staff to review the B/C ratio to select economic projects in Phase 1, as members expressed opinions that the proposed values are too high (Attachment 4 – DPP – Projects Selection Methodology)

Closing Items

Chair Alan Myers (ITC Great Plains, LLC) requested if any other items merited discussion.

The meeting was adjourned at 11:38 a.m.

Respectfully Submitted,

Juliano Freitas,

Secretary

Name	Email	Attendance
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Al Tamimi	atamimi@sunflower.net	Webex
Alan Myers	amyers@itcgreatplains.com	Webex
Antoine Lucas	alucas@spp.org	Webex
Ben Roubique	broubique@pwrsol.biz	Webex
Bennie Weeks	bennie.weeks@xcelenergy.com	Webex
Bill Leung (NPRB)	bleung@bjleung.com	Webex
Bruce Walkup (AECC)	bruce.walkup@aecc.com	Webex
Caitlin Shank	cshank@spp.org	Webex
Cory Blair (RES Americas)	cory.blair@res-americas.com	Webex
David Treichler	david.treichler@oncor.com	Webex
Deral Danis (Clean Line)	ddanis@cleanlineenergy.com	Webex
Don Le	don.le@nexteraenergy.com	Webex
Eric Burkey (Ameren)	eburkey@ameren.com	Webex
Gayle Freier (SPP)	gfreier@spp.org	Webex
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Jerry Bradshaw (CUS)	jerry.bradshaw@cityutilities.net	Webex
Jim Jacoby	jwjacoby@aep.com	Webex
Joe Lang	jlang@les.com	Webex
Jon Iverson	jiverson@oppd.com	Webex
Jon Shipman (OPPD)	jeshipman@oppd.com	Webex
Josh Ross	jross@spp.org	Webex
Juliano Freitas	jfreitas@spp.org	Webex
Kaustubh Deshmukh	kdeshmukh@itctransco.com	Webex
Kelsey Allen	kallen@spp.org	Webex
Kirk Hall	khall@spp.org	Webex
Kurt Stradley (LES)	kstradley@les.com	Webex
Leon Howell	howelllc@oge.com	Webex
Liz Coffield (SPP)	lcoffield@spp.org	Webex
Michael Watt (OMPA)	mwatt@ompa.com	Webex
Mike Proctor	mproctor910@sbcglobal.net	Webex
Nathan McNeil (MIDW)	nmcneil@mwenergy.com	Webex
Noumvi Ghomsi	nghomsi@gmail.com	Webex
Pat Hayes (Ameren)	phayes@ameren.com	Webex
Pat McCool	patrick.mccool@kcpl.com	Webex
Paul Dietz	paul.dietz@westarenergy.com	Webex
Randy Collier (CUS)	randy.collier@cityutilities.net	Webex
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ECONOMIC STUDIES WORKING GROUP

April 24th, 2014

Conference Call

• A G E N D A •

8:30 am – 11:30 am

1. Administrative items
    a. Call to Order, Introductions ..... Alan Myers (5 minutes)
    b. Receipt of Proxies ..... Juliano Freitas (1 minute)
    c. Review of Agenda ..... Alan Myers (1 minute)
2. Metrics Review ..... SPP Staff (2 hours)
3. DPP Project Selection Methodology ..... Juliano Freitas (1 hour)
4. Closing Items ..... All

Metrics Review

April 10th, 2014

SPP Southwest Power Pool

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

Overview

- ESWG has been tasked with reviewing the calculation of metrics going forward
  - ITP10
  - RCAR 2
- Today – continue discussion of metrics that have been developed previously
  - Focus will be on the calculation of metrics that have received more attention from stakeholders during ITP and the previous RCAR

Approved Metrics for the RCAR

- Adjusted Production Cost (APC) Savings
- Reduction of Emission Rates and Values
- Savings due to Lower Ancillary Service Needs and Production Costs
- Avoided or Delayed Reliability Projects
- Capacity Cost Savings due to Reduced On-Peak Transmission Losses
- Mitigation of Transmission Outage Costs
- Assumed Benefit of Mandated Reliability Projects
- Public Policy Benefits

ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

Reliability Benefit Allocation Methodologies

- **Highway/Byway – utilized in RCAR**
- **DFAX**
- **LODF**
- **System Reconfiguration**

*These allocation methodologies do not impact the total reliability benefit of projects. They only impact the allocation of benefit to zones.

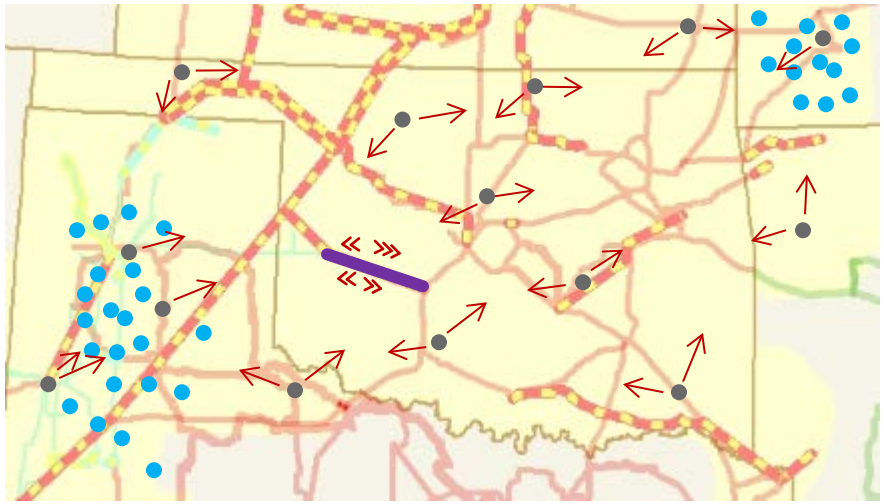
Highway/Byway Approach

- Benefits would be allocated in the same manner costs are allocated
- For upgrades > 300 kV:
  - 100% of benefit allocated to the region, based on Load Ratio Share (LRS)
- For upgrades between 100 kV and 300 kV:
  - 1/3 of benefit allocated to the region, based on LRS
  - 2/3 of benefit allocated to the zone
- For upgrades < 100 kV:
  - 100% of benefit allocated to the zone

DFAX Approach

- Distribution factors (DFAX) used to calculate the portion of a transfer of energy from a defined source to a defined sink that will flow across a specific transmission facility
- A DFAX is calculated for each transmission zone by modeling a transfer from all generation in the SPP region individually to the loads in each transmission zone
- The change in flow for the reliability upgrade was calculated for each of the zonal transfers
- DFAX represent a measure of the use by the load of each transmission zone of the required Reliability Project as determined by power flow analysis

DFAX Approach



Large DFAX -> large benefit

Small DFAX -> small benefit

DFAXs for each of the 16 transfers are normalized to develop allocation factors. These allocation factors are then normalized based on peak load by zone to obtain final allocation factors.

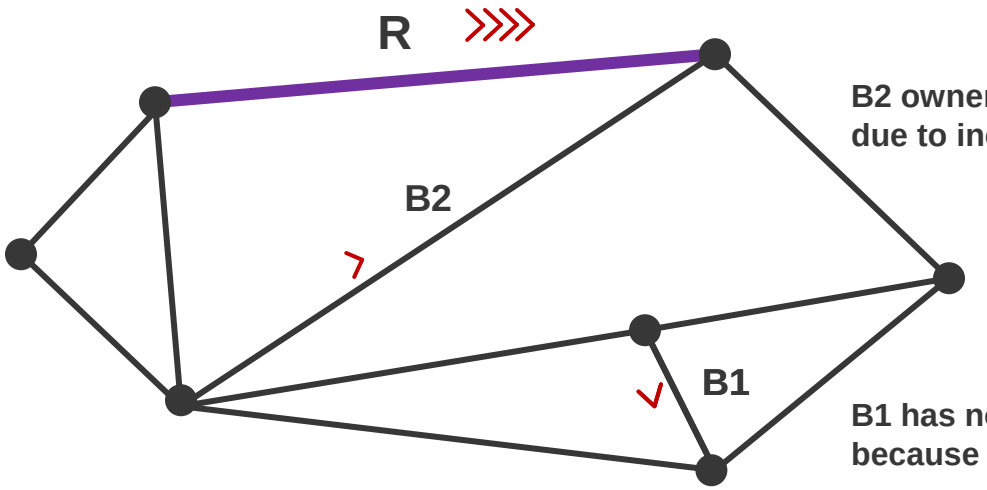
Zones with transfers that impact the reliability upgrade flow the most will have the most benefit.

Line Outage Distribution Factor (LODF) Approach

- N-1 Contingency Analysis
- Change in flow for Reliability Upgrade computed for each outage (LODF)
- Increase in flow for Reliability Upgrade due to Zone A Outage is credited as benefit to Zone A
- Sum of LODFs by zone are normalized to compute allocation factors by zone

LODF Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



B2 owner is assigned benefit, due to increased flow on R

B1 has no impact on benefit, because flow on R stays same

Outage taken for every branch, 1 by 1, and increase in flow on R is measured

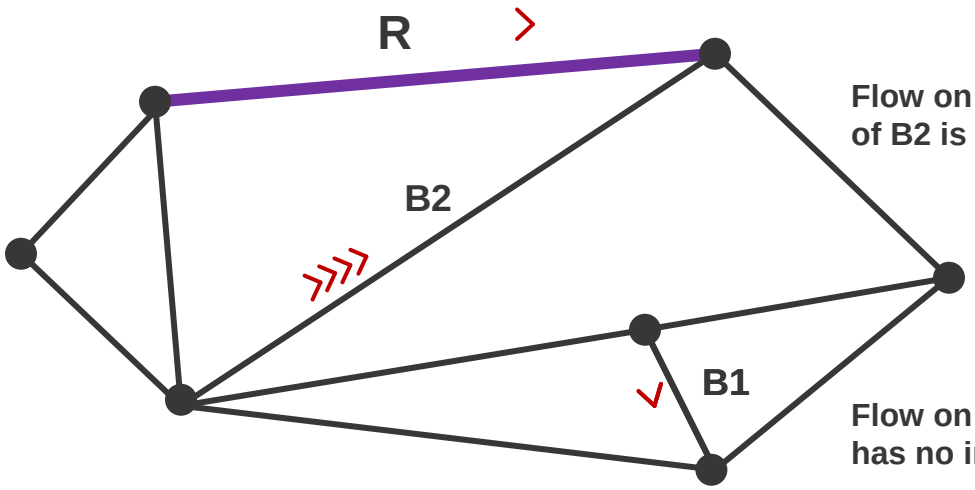
Benefits assigned to zones based on who owns the outaged facilities that cause increases in flow on R

System Reconfiguration Approach

- This approach is modified form of the MW-mile cost allocation utilized prior to Highway/Byway
  - This approach does not utilize line lengths
- Analyze all flows both with and without the reliability upgrade
  - Lines with increased flows after reliability upgrade is outaged are identified as beneficiaries of the reliability upgrade
  - Zones that own these lines are credited with reliability benefit
  - Approach and results are very similar to LODF

System Reconfiguration Approach

R = Reliability Upgrade
B1 = Branch 1
B2 = Branch 2



Flow on B2 increases, owner of B2 is assigned benefit

Flow on B1 stays the same. B1 has no impact on benefit.

Flow on every branch is analyzed, 1 by 1, to determine if flow increased as a result of R being outaged

Benefit assigned to zones based on who owns the branches with increased flow after R is outaged

PJM Allocation Method

Cost Allocation Example

- 5 LDAs
- 1 upgrade (U1) resolves one or more criteria violations
- DFAX cutoff = 1%
- Usage: 80%/20% of U1 MWh is projected to be in the positive/negative direction

LDA	Peak Load (MW)	DFAX on U1 (%)
1	10,000	5.0
2	6,000	-10.0
3	4,000	0.9
4	3,000	-3.0
5	2,000	10.0

Cost Allocation Example

Step	Reference	LDA 1	LDA 2	LDA 3	LDA 4	LDA 5	Total
1. Peak Load (MW)	From PJM Load Report	10,000	6,000	4,000	3,000	2,000	25,000
2. DFAX	From DFAX Analysis	5.0%	-10.0%	0.9%	-3.0%	10.0%	
3. Positive Impact (MW)	Line 1 * Line 2 if DFAX is >= 1% Else 0	500	0	0	0	200	700
4. Negative Impact (MW)	Line 1 * Line 2 if DFAX is =< -1% Else 0	0	-600	0	-90	0	-690
5. Positive Usage	Line 5 Total * Line 3 / Line 3 Total (Line 5 Total From Production Cost Simulation)	57.14%	0	0	0	22.86%	80%
6. Negative Usage	Line 6 Total * Line 4 / Line 4 Total (Line 6 Total From Production Cost Simulation)	0	17.39%	0	2.61%	0	20%
7. DFAX Allocation	Line 5 + Line 6	57.14%	17.39%	0%	2.61%	22.86%	100%

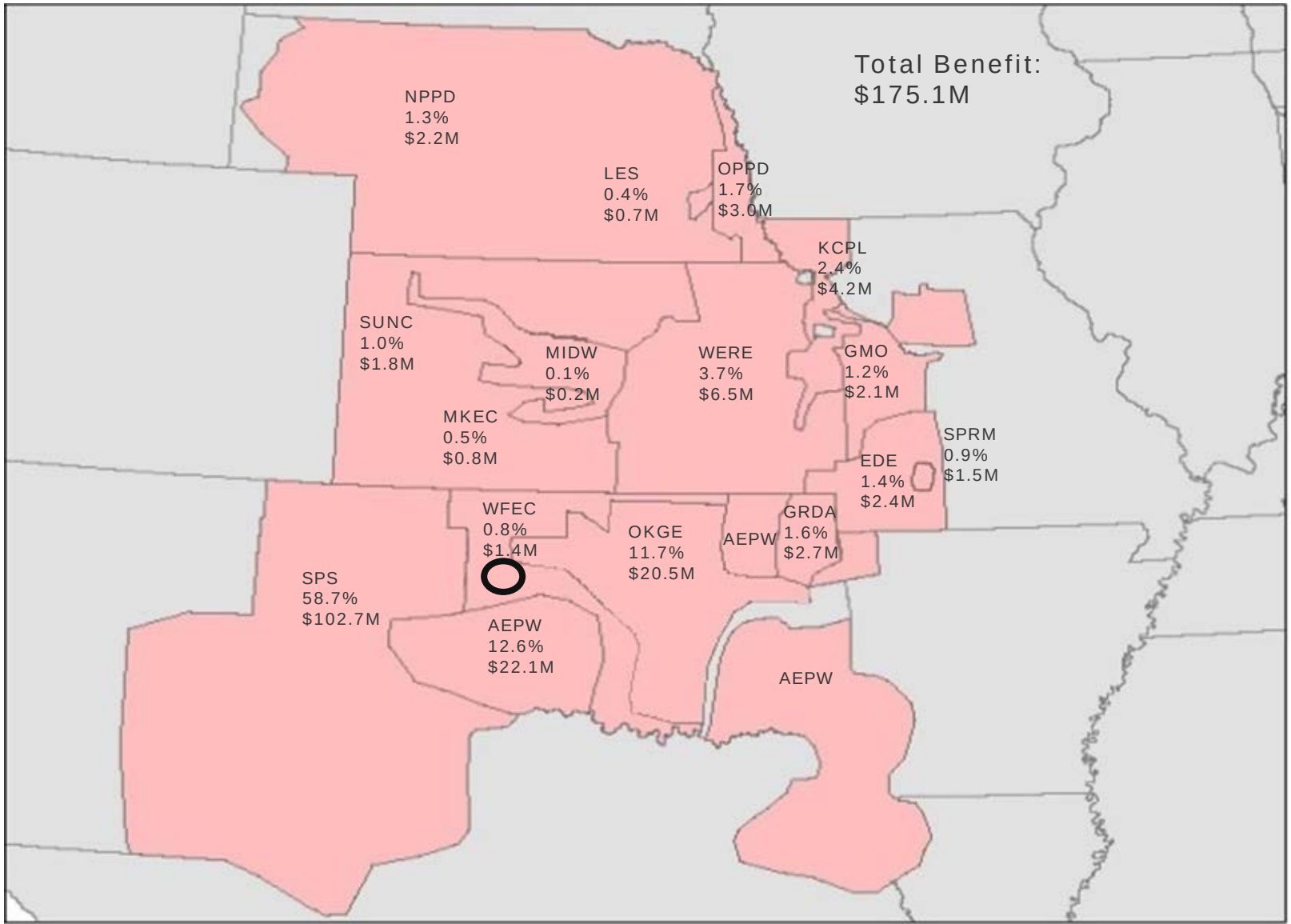
* For Regional and Necessary Lower Voltage Facilities greater than or equal to $5 Million, the allocation for each LDA will be the average of the DFAX allocation and the LDA load ratio share based on the appropriate Network Service Peak Loads.

This methodology was used for final allocations in the DFAX, LODF, and System Reconfiguration Approaches

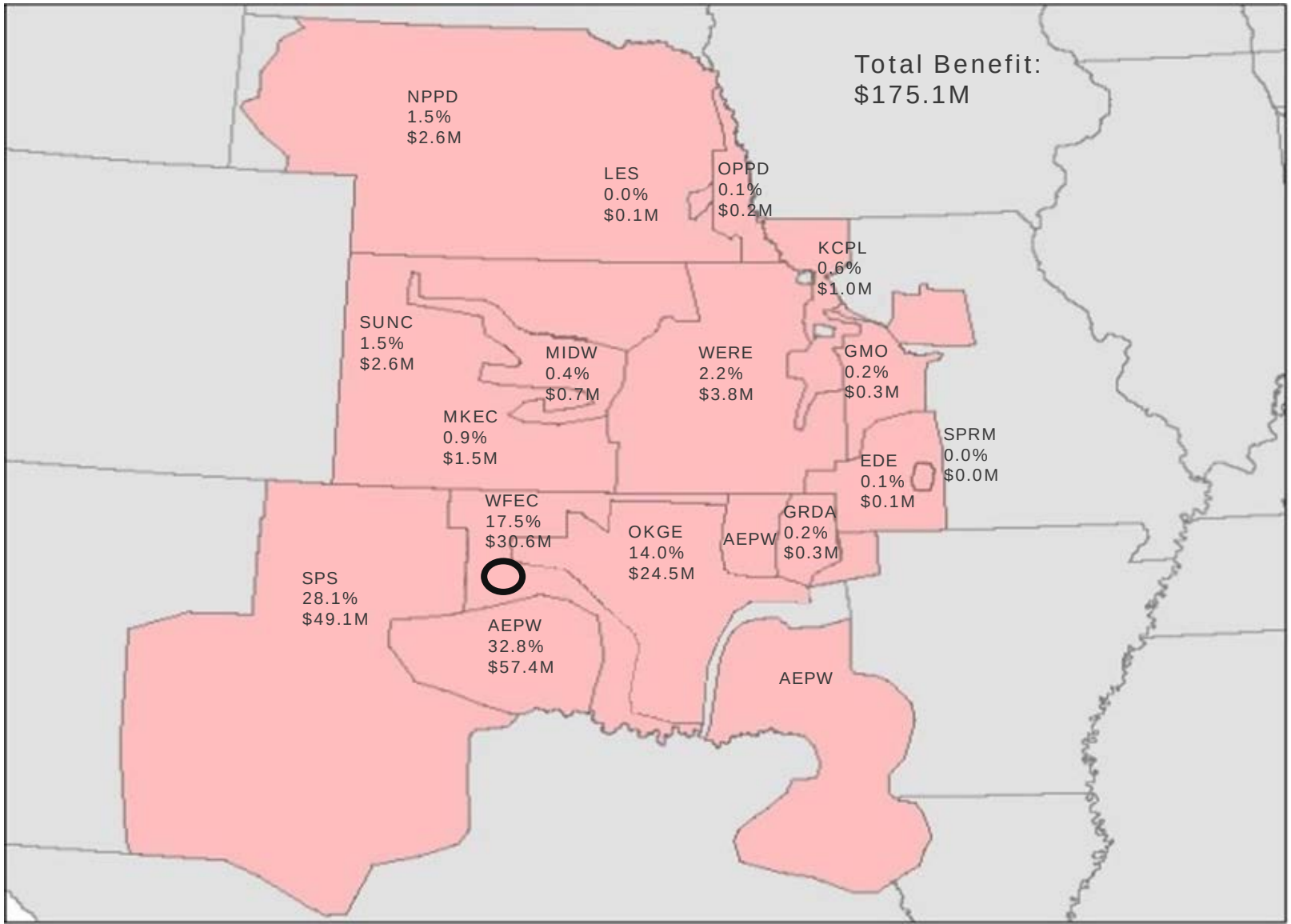
Examples

- Considered three existing reliability projects
  - Summit – Elm Creek 345 (central KS)
  - Elk City – Gracemont 345 (west OK)
  - Oronogo Jct – Riverton 161 (southwest MO)
- For each, compared the benefit allocation results using the different approaches
  - Highway/Byway – used in RCAR
  - DFAX
  - LODF
  - System Reconfiguration

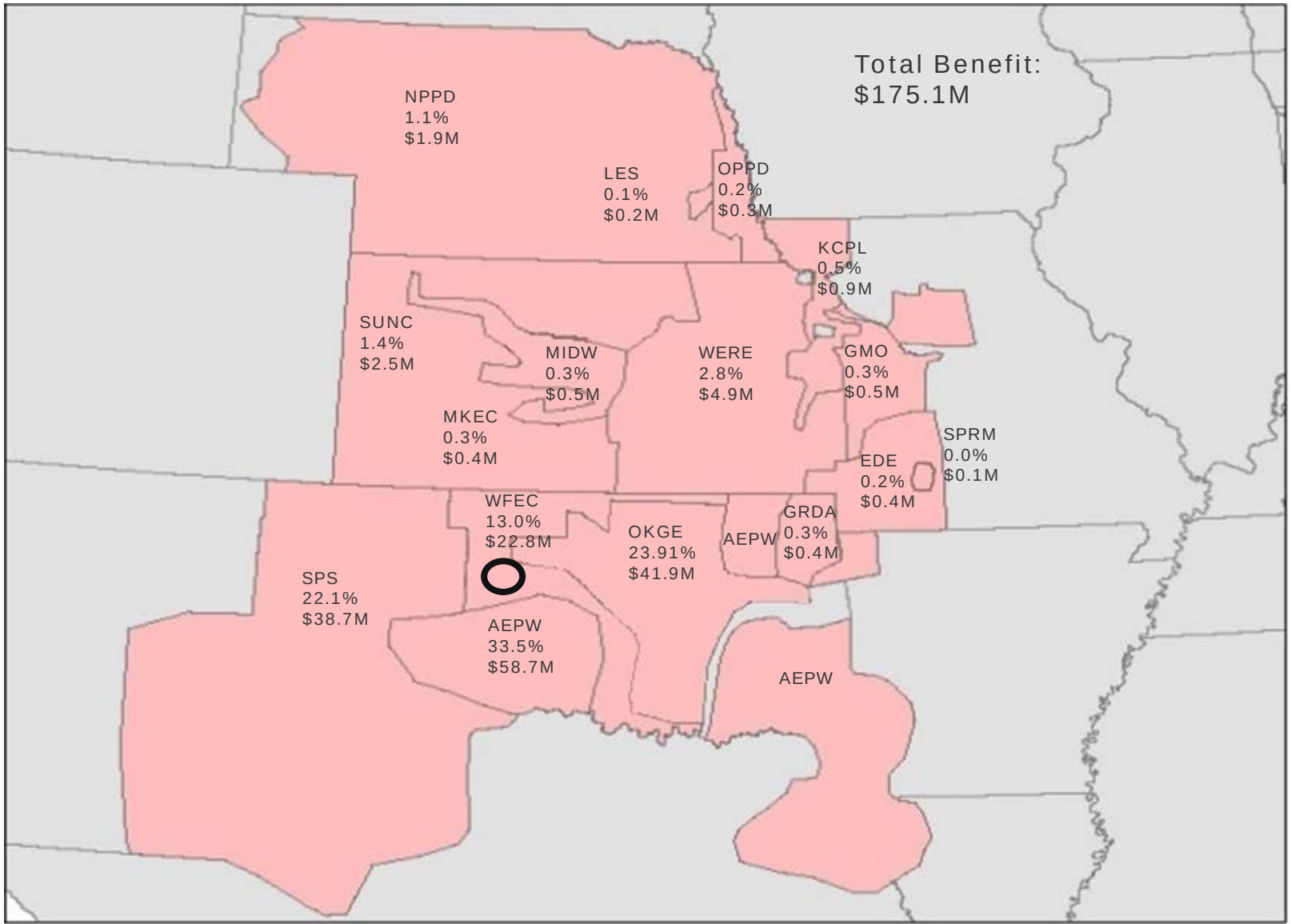
DFAX – Elk City to Gracemont 345 kV



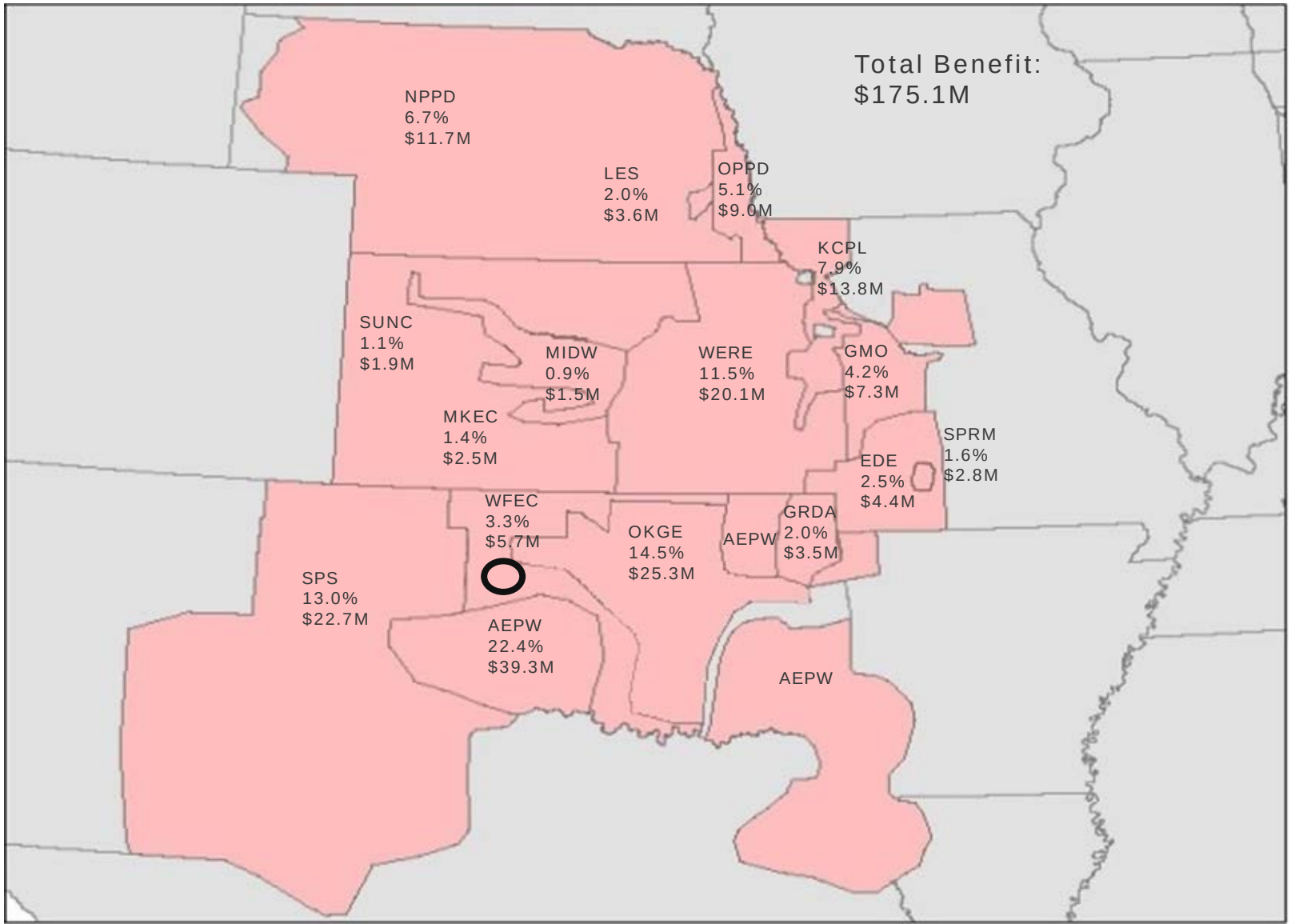
LODF – Elk City to Gracemont 345 kV



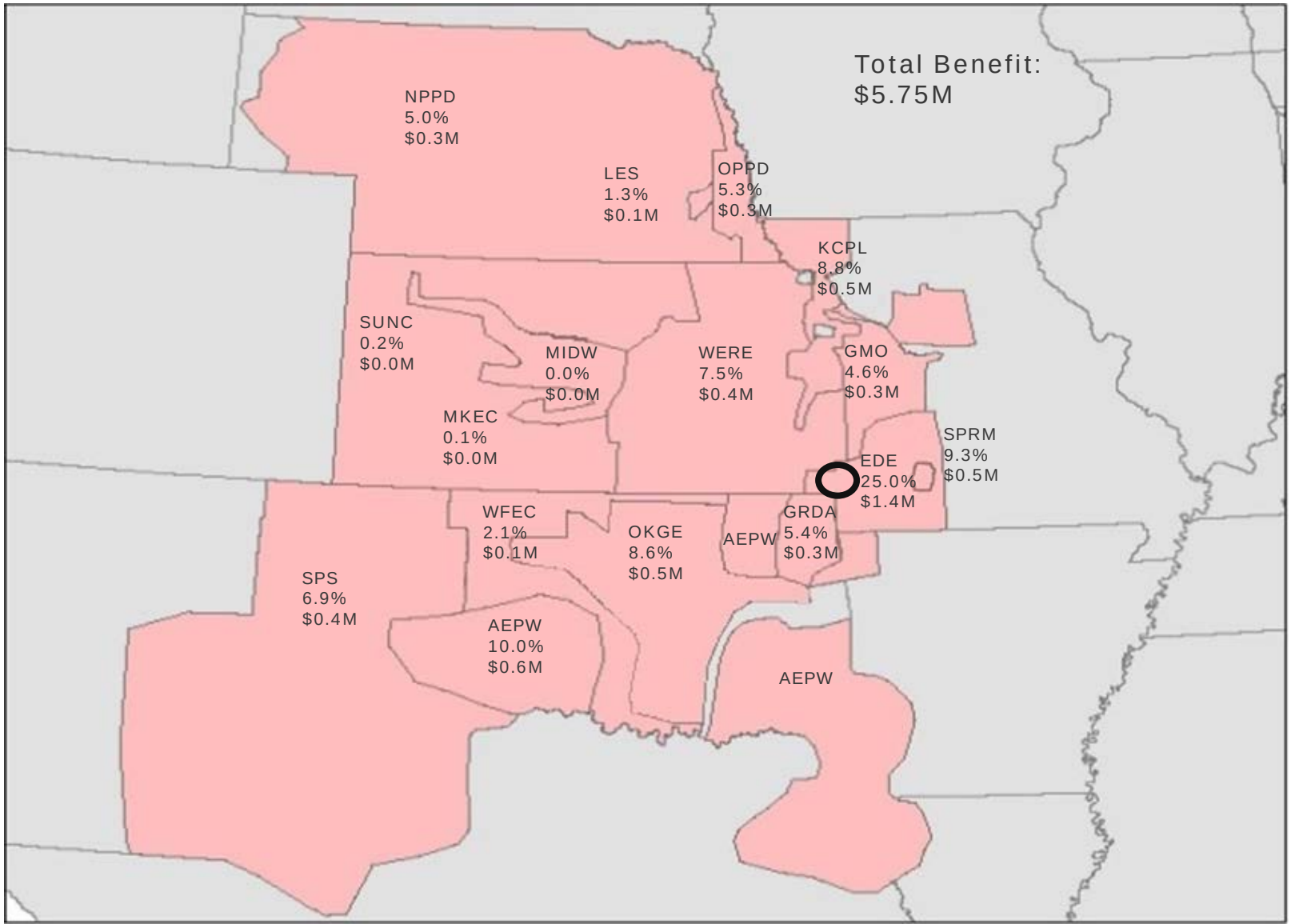
System Reconfiguration – Elk City to Gracemont 345 kV



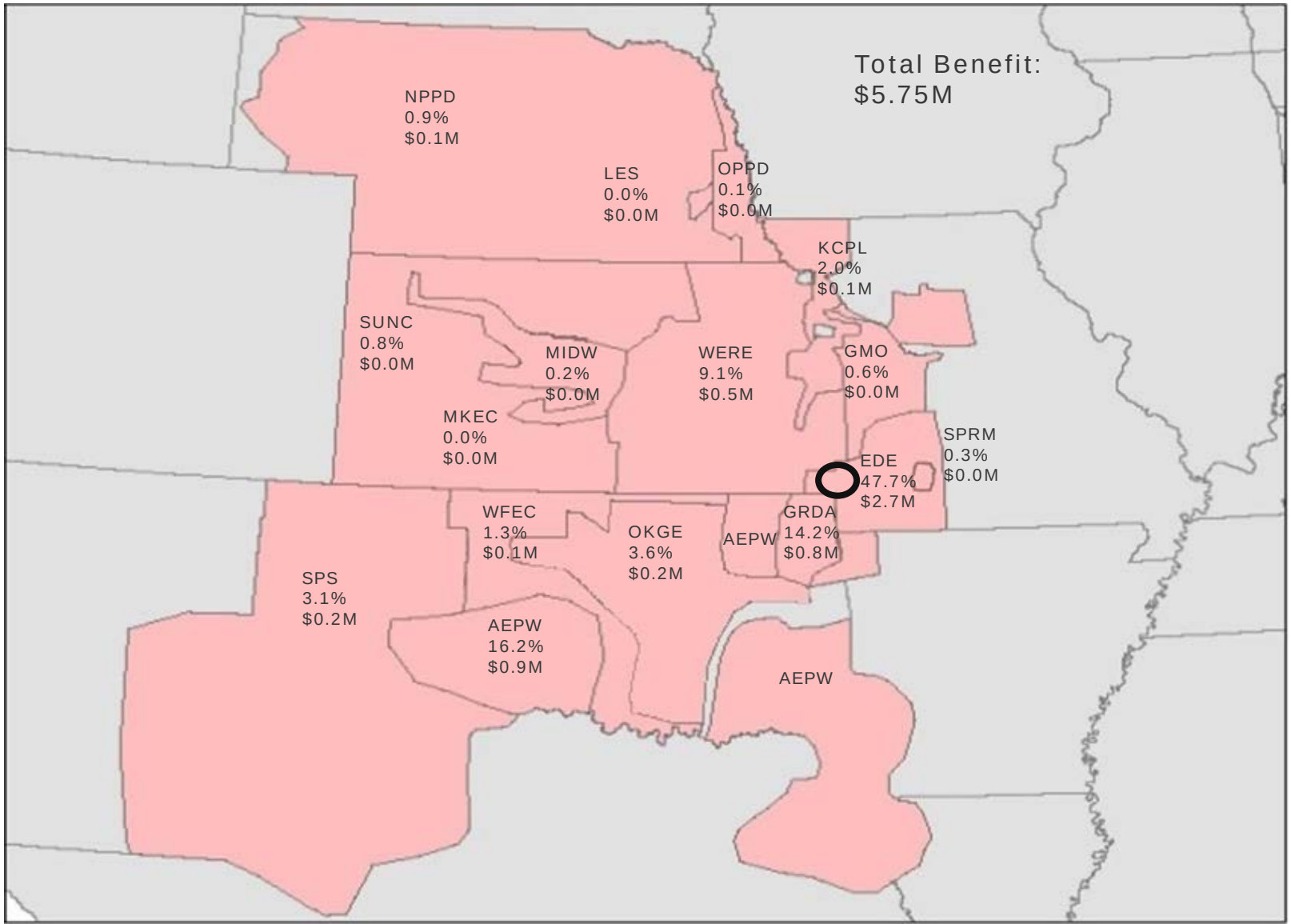
Highway/Byway – Elk City to Gracemont 345 kV



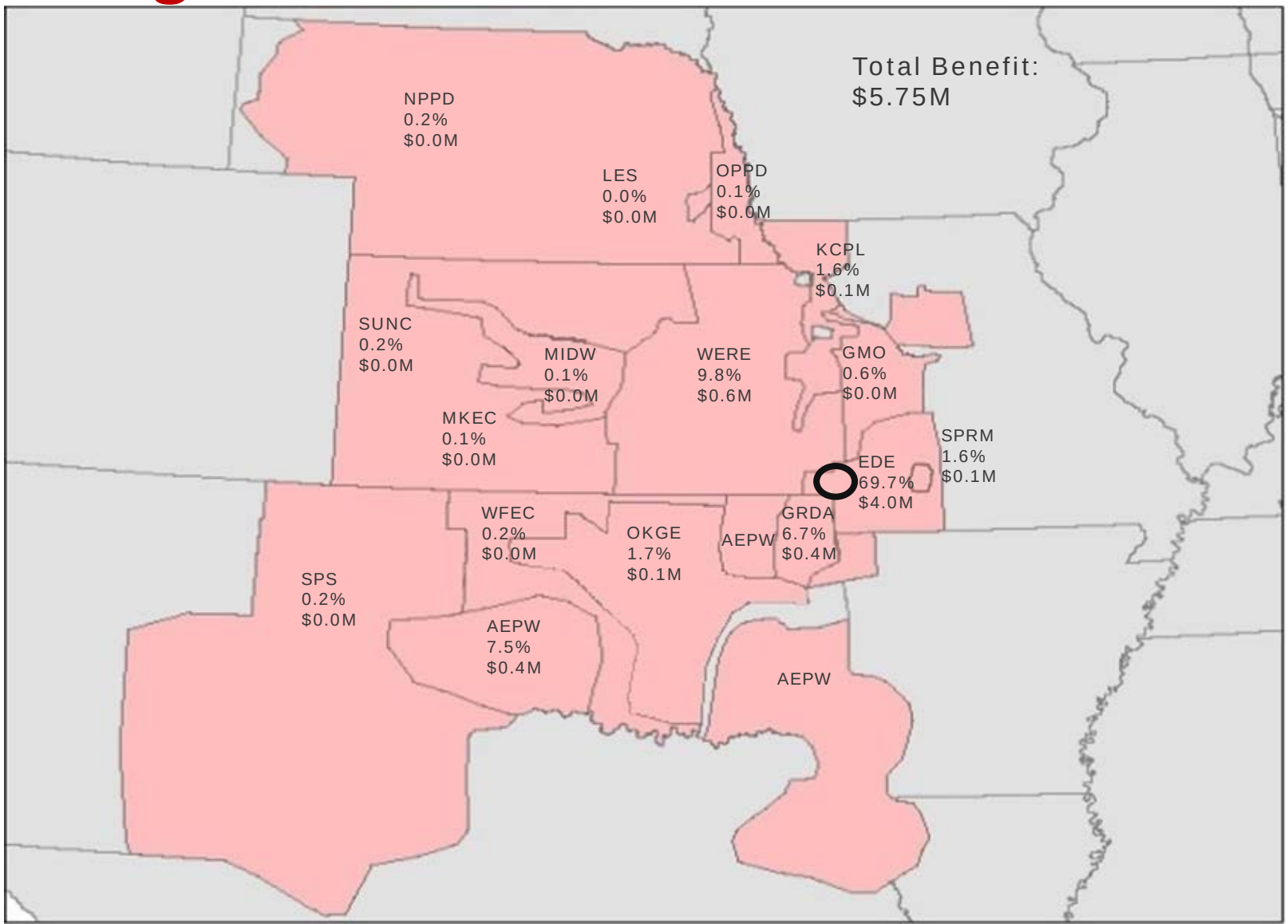
DFAX – Riverton to Oronogo 161 kV



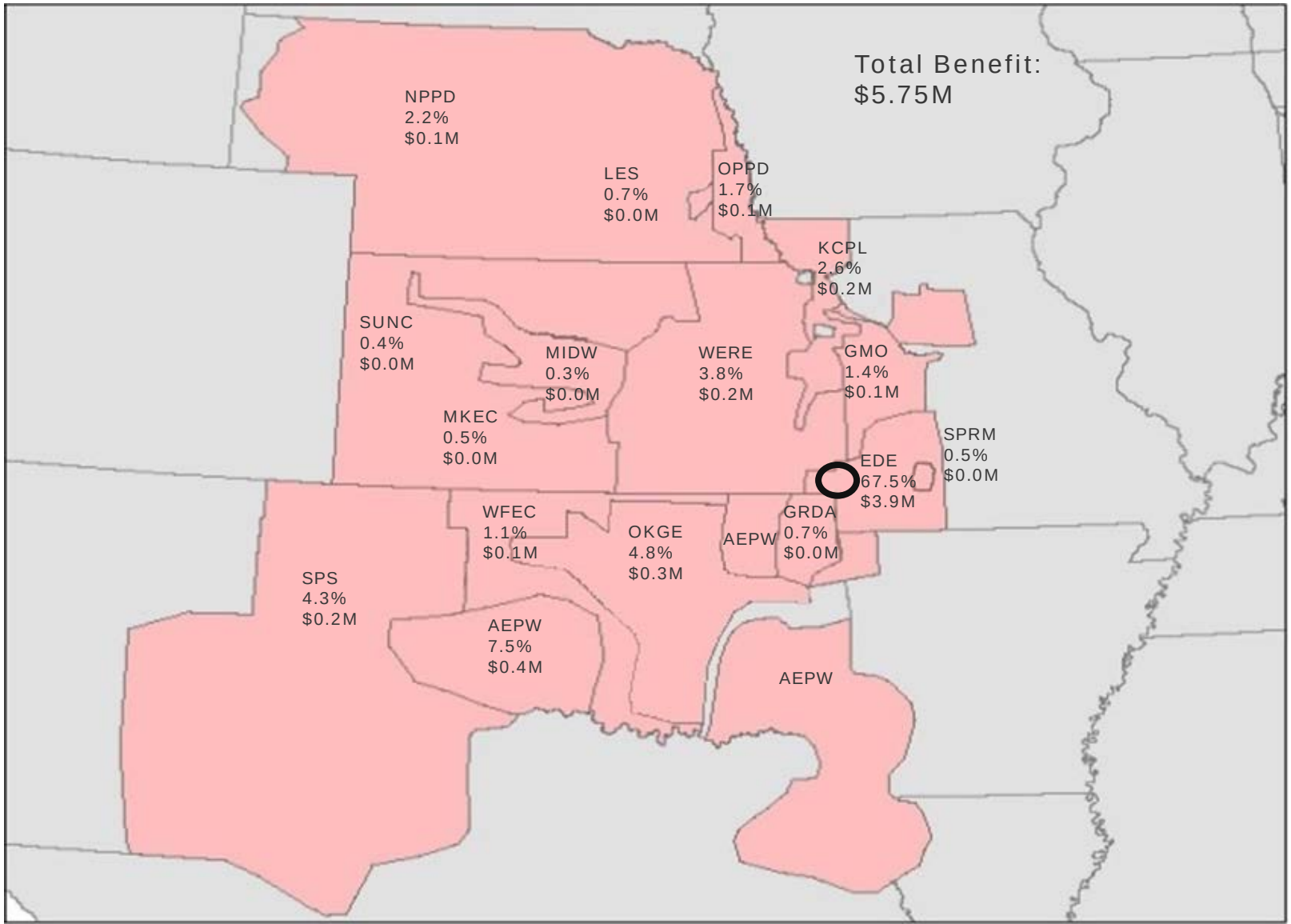
LODF – Riverton to Oronogo 161 kV



System Reconfiguration – Riverton to Oronogo 161 kV



Highway/Byway – Riverton to Oronogo 161 kV



Results Comparison – Elk City to Gracemont 345

Elk City - Gracemont 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$39,292,246	12.61%	$22,070,635	32.80%	$57,426,760	33.50%	$58,652,851
523	GRDA	2.01%	$3,523,360	1.56%	$2,732,454	0.18%	$308,351	0.25%	$441,514
524	OKGE	14.47%	$25,325,133	11.73%	$20,542,390	14.01%	$24,519,535	23.91%	$41,851,230
525	WFEC	3.27%	$5,723,806	0.82%	$1,442,962	17.49%	$30,623,101	13.00%	$22,763,222
526	SPS	12.98%	$22,725,093	58.67%	$102,707,267	28.07%	$49,143,574	22.11%	$38,711,584
531	MIDW	0.85%	$1,485,501	0.13%	$228,919	0.40%	$706,122	0.28%	$483,359
534	SUNC	1.08%	$1,893,089	1.00%	$1,757,112	1.48%	$2,587,438	1.44%	$2,513,189
536	WERE	11.48%	$20,100,127	3.73%	$6,527,446	2.19%	$3,836,896	2.81%	$4,919,923
540	GMO	4.18%	$7,318,366	1.21%	$2,123,400	0.19%	$329,406	0.27%	$471,908
541	KCPL	7.86%	$13,761,449	2.39%	$4,179,816	0.57%	$999,096	0.51%	$899,100
544	EMDE	2.53%	$4,430,995	1.38%	$2,422,150	0.08%	$146,083	0.20%	$357,008
546	SPRM	1.59%	$2,782,656	0.88%	$1,536,618	0.03%	$44,045	0.04%	$66,146
640	NPPD	6.69%	$11,706,991	1.29%	$2,249,917	1.49%	$2,613,735	1.10%	$1,925,600
645	OPPD	5.11%	$8,953,392	1.73%	$3,031,455	0.09%	$158,632	0.20%	$349,009
650	LES	2.03%	$3,555,862	0.40%	$706,349	0.04%	$78,612	0.12%	$208,336
539	MKEC	1.42%	$2,483,325	0.46%	$802,503	0.88%	$1,540,005	0.26%	$447,414
Total		100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392	100.00%	$175,061,392

Results Comparison – Summit to Elm Creek 345

Summit - Elm Creek 345		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	22.44%	$25,373,674	22.96%	$25,952,226	4.03%	$4,553,167	2.49%	$2,813,179
523	GRDA	2.01%	$2,275,273	2.93%	$3,316,056	0.52%	$586,534	0.46%	$523,117
524	OKGE	14.47%	$16,354,160	23.50%	$26,570,727	1.46%	$1,644,876	3.06%	$3,463,442
525	WFEC	3.27%	$3,696,250	6.75%	$7,627,840	0.44%	$496,188	0.46%	$522,626
526	SPS	12.98%	$14,675,137	32.20%	$36,401,169	3.82%	$4,317,980	0.29%	$324,247
531	MIDW	0.85%	$959,289	0.00%	$401	13.38%	$15,123,684	3.22%	$3,636,323
534	SUNC	1.08%	$1,222,496	0.00%	$479	14.63%	$16,536,242	18.64%	$21,067,896
536	WERE	11.48%	$12,980,018	9.44%	$10,677,305	33.07%	$37,386,161	52.24%	$59,057,673
540	GMO	4.18%	$4,725,966	0.00%	$2,998	0.76%	$854,705	0.75%	$848,003
541	KCPL	7.86%	$8,886,703	0.01%	$5,860	3.64%	$4,112,908	3.06%	$3,461,328
544	EMDE	2.53%	$2,861,394	1.57%	$1,773,728	0.17%	$192,165	0.29%	$323,853
546	SPRM	1.59%	$1,796,950	0.60%	$674,452	0.04%	$40,154	0.24%	$273,791
640	NPPD	6.69%	$7,560,000	0.01%	$12,617	6.38%	$7,211,929	4.41%	$4,981,700
645	OPPD	5.11%	$5,781,814	0.01%	$10,032	1.51%	$1,703,673	1.30%	$1,469,425
650	LES	2.03%	$2,296,261	0.00%	$3,177	0.27%	$299,720	0.66%	$746,945
539	MKEC	1.42%	$1,603,652	0.02%	$19,973	15.91%	$17,988,953	8.43%	$9,535,489
Total		100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038	100.00%	$113,049,038

Results Comparison – Riverton to Oronogo 161

Riverton - Oronogo Jct 161		Highway/Byway		DFAX		LODF		System Reconfiguration	
Area Number	Area Name	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)	Allocation Factor	Reliability Benefit ($)
520	AEPW	7.48%	$430,193	9.97%	$573,526	16.23%	$933,380	7.48%	$430,259
523	GRDA	0.67%	$38,576	5.40%	$310,715	14.24%	$818,671	6.70%	$385,052
524	OKGE	4.82%	$277,273	8.55%	$491,670	3.58%	$205,656	1.65%	$95,045
525	WFEC	1.09%	$62,667	2.14%	$123,087	1.25%	$71,752	0.20%	$11,267
526	SPS	4.33%	$248,807	6.94%	$398,963	3.06%	$175,774	0.15%	$8,815
531	MIDW	0.28%	$16,264	0.03%	$1,926	0.21%	$11,918	0.06%	$3,168
534	SUNC	0.36%	$20,727	0.17%	$9,595	0.78%	$44,842	0.20%	$11,574
536	WERE	3.83%	$220,067	7.48%	$430,386	9.06%	$520,986	9.79%	$562,770
540	GMO	1.39%	$80,125	4.60%	$264,345	0.58%	$33,208	0.58%	$33,189
541	KCPL	2.62%	$150,668	8.75%	$502,903	1.97%	$113,406	1.60%	$92,086
544	EMDE	67.51%	$3,881,846	24.96%	$1,435,197	47.68%	$2,741,646	69.67%	$4,005,990
546	SPRM	0.53%	$30,466	9.29%	$534,013	0.33%	$18,923	1.56%	$89,502
640	NPPD	2.23%	$128,174	5.00%	$287,277	0.90%	$51,580	0.24%	$14,026
645	OPPD	1.70%	$98,027	5.28%	$303,698	0.10%	$5,563	0.05%	$3,066
650	LES	0.68%	$38,931	1.32%	$75,949	0.04%	$2,333	0.02%	$1,023
539	MKEC	0.47%	$27,189	0.12%	$6,753	0.01%	$362	0.06%	$3,168
Total		100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000	100.00%	$5,750,000

Comparison of Alternative Approaches

	DFAX	LODF	System Reconfiguration
Does it impact the total reliability benefit for a project?	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones	No; only impacts allocation of benefit to zones
Does it measure how overloaded a line is or isn't?	No	No	No
Emphasizes use of the upgrade by…..	Zonal loads	Zonal branches	Zonal branches
Measures……	How much the upgrade is utilized in serving a zone's load	Additional flows that the upgrade will pick up when a zone's existing facilities are outaged	Additional flows that a zone's facilities will pick up when the upgrade is outaged
General allocation observation from examples	Allocation is slightly more levelized than the other two alternatives	Significant benefit going to a few zones closest to upgrade	Significant benefit going to a few zones closest to upgrade
Complexity in evaluating numerous projects	Moderate to difficult	Moderate	Moderate
Does it utilize PJM method of allocating based on how often flow on upgrade is positive or negative, and whether shift factor is positive or negative?	Yes	Yes	Yes
Other Notes	All SPP generators scaled. DFAX results were normalized based on peak load by zone	Similar to the System Reconfiguration approach, but a reverse variation of it.	Similar to the LODF approach, but a reverse variation of it. This is the MW-mile approach without accounting for mileage.

PUBLIC POLICY BENEFITS

Public Policy Benefits – Previous Approach

- Benefits allocated to zones in proportion to each zone's share of unmet renewable energy goals.
  - Public Policy Benefit per zone = (% share of unmet goals) x (cost of upgrade)
  - If a zone has no public policy mandate or goal, or already meets their mandate or goal, their public policy benefit is zero
- Production cost savings due to policy upgrades are additional to this benefit

Potential Alternative for Benefit Allocation

- Public Policy Benefit is allocated only to zones in the state in which the mandate/goal is driving the project
- New Gentleman – Cherry – Holt 345 kV line
  - Driven by Nebraska goal
  - Benefits allocated to Nebraska entities
  - Total 40-Year Cost = Public Policy Benefit = $296.4 M

	Unmet Renewable Goal* (MWh)	% Share of Unmet Renewable Goal	Public Policy Benefit (millions $)
NPPD	1,374,534	48%	$143
OPPD	1,470,070	52%	$153
LES	0	0%	$0
Total	**2,844,604**	**100%**	**$296**

*These numbers represent unmet goals from the RCAR; these are not up-to-date with ITP10 data

State Policy Benefit Allocation – Example

	Unmet Renewable Goal (MWh)	% Share of **SPP** Unmet Renewable Goal	Public Policy Benefit - RCAR ($M)	% Share of **Nebraska** Unmet Renewable Goal	Public Policy Benefit - State Policy Allocation ($M)
AEPW	1,787,126	10.1%	$30	0.0%	$0
CUS	0	0.0%	$0	0.0%	$0
EDE	887,873	5.0%	$15	0.0%	$0
GMO	1,737,706	9.8%	$29	0.0%	$0
GRDA	0	0.0%	$0	0.0%	$0
KCPL	2,906,537	16.4%	$49	0.0%	$0
LES	0	0.0%	$0	0.0%	$0
MIDW	0	0.0%	$0	0.0%	$0
MKEC	228,122	1.3%	$4	0.0%	$0
NPPD	1,374,534	7.8%	$23	48.3%	$143
OKGE	3,485,957	19.7%	$58	0.0%	$0
OPPD	1,470,070	8.3%	$25	51.7%	$153
SUNC	126,037	0.7%	$2	0.0%	$0
SWPS	0	0.0%	$0	0.0%	$0
WEFA	804,394	4.6%	$13	0.0%	$0
WRI	2,868,358	16.2%	$48	0.0%	$0
Total	17,676,714	100.0%	$296	100.0%	$296

*If a policy project enables members in multiple states to meet their mandates/goals, the benefit would be applied to all impacted members

MITIGATION OF TRANSMISSION OUTAGES

Mitigation of Outage Costs – Existing Approach

- Add set of historical transmission outages to production cost simulations
- Benefit = APC Benefit$_{\text{With Outages}}$ – APC Benefit$_{\text{Without Outages}}$
  - This metric is an adder to traditional APC Benefit
- Since it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone, this benefit is calculated on an SPP-wide basis and allocated to zones based on a load ratio share.

APC Savings Allocation Approach

- For APC Savings with no outages, calculate each zone's benefit as a percentage of the total SPP benefit
- Multiply each zone's APC benefit % by the Mitigation of Transmission Outage Costs total benefit to determine that zone's allocation of the Total Outage benefit

APC Savings Allocation Approach

	Mitigation of Transmission Outages Benefit - RCAR, based on LRS ($M)	APC Savings - 40-year NPV benefit* ($M)	Percent of Total APC Savings	Mitigation of Transmission Outages Benefit - allocated by APC Savings % ($M)
AEPW	$76	$240	7.9%	$27
CUS	$5	$7	0.2%	$1
EDE	$9	$7	0.2%	$1
GMO	$14	$23	0.8%	$3
GRDA	$7	$10	0.3%	$1
KCPL	$27	$24	0.8%	$3
LES	$7	$5	0.2%	$1
MIDW	$3	$60	2.0%	$7
MKEC	$5	$42	1.4%	$5
NPPD	$23	$226	7.5%	$25
OKGE	$49	$175	5.8%	$20
OPPD	$17	$34	1.1%	$4
SUNC	$4	-$10	-0.3%	-$1
SWPS	$44	$1,939	64.2%	$218
WEFA	$11	$24	0.8%	$3
WRI	$39	$215	7.1%	$24
Total	$340	$3,021	100.0%	$340

Historical Outage Data Approach

- Obtained operational data for outages from Sept 2011 to present
  - Number of outages by zone
  - Operations used different application before Sept 2011, making it more difficult to query and organize data prior to Sept 2011
  - Some tie lines are being double counted (~5% of outages)
- Number of outages by zone was divided by total outages for region to obtain allocation factor by zone
- Allocation factor multiplied by total outages benefit

Historical Outage Data Approach

Zone	# of outages	Allocation %	Benefit based on outage data ($M)	Benefit based on LRS, from RCAR ($M)	Increase in Benefit with new methodology ($M)
AEP	3,044	21.64%	$74	$76	($2)
EDE	545	3.88%	$13	$9	$4
GRDA	273	1.94%	$7	$7	($0)
KCPL	431	3.06%	$10	$27	($17)
LES	212	1.51%	$5	$7	($2)
MIDW	123	0.87%	$3	$3	($0)
GMO	393	2.79%	$10	$14	($4)
NPPD	1,492	10.61%	$36	$23	$13
OKGE	2,326	16.54%	$56	$49	$7
OPPD	434	3.09%	$10	$17	($7)
SUNC/MKEC	602	4.28%	$15	$9	$6
CUS	218	1.55%	$5	$5	$0
SPS	2,238	15.91%	$54	$44	$10
WFEC	399	2.84%	$10	$11	($1)
WR	1,334	9.49%	$32	$39	($7)
Total	14,064	100.00%	$340	$340	$0

INCREASED WHEELING THROUGH AND OUT REVENUES

Increased Wheeling Through and Out Revenues

- Increased ATC with neighbors can lead to increased through and out transactions, that can increase SPP wheeling revenues
  - Schedules 7, 8, 11
  - Metric does not capture the energy revenue from increased exports, only the wheeling revenue

Increased Wheeling – Calculation

- Increased Wheeling Benefit ($) = (Increased annual MWh exports) * (Average $/MWh Wheeling Charge)
  - Use PROMOD simulations to determine annual MWh exports in the base and change cases
  - Average $/MWh Wheeling Charge =

$$\frac{Total\ SPP\text{–}wide\ wheeling\ revenues\ for\ 2013}{Total\ MWh\ wheeling\ through\ and\ out\ transactions\ for\ 2013}$$

- MTF Recommendation: Allocate to zones based on Load Ratio Share

MARGINAL ENERGY LOSSES BENEFIT

Marginal Energy Losses Benefit

- Full MWh losses are not reflected in standard production cost simulations
- Energy loss savings can be calculated through post-processing of simulations
  - Based on Marginal Loss Revenues
- The calculation is performed for each zone

APPENDIX – METRICS REVIEW CALCULATIONS

DFAX Approach

For 10 MW transfer:

DFAX = (Post-transfer MW flow – Pre-transfer MW flow)/10 MW, in which:

- **Pre-transfer MW flow = MW flow over transmission upgrade before the 10 MW transfer**
- **Post-transfer MW flow = MW flow over transmission upgrade after the 10 MW transfer**

Wind units are excluded from the scaling

Units with GSF > 20% are excluded from the scaling

In this pass, ALL other generators were scaled up equally.

Transfers with positive DFAX are grouped together, and transfers with negative DFAX are grouped together

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Positive\ DFAX's}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) * \boldsymbol{LRS}, if\ DFAX_{Zone\ A}\ is(+)$$

$$Allocation\ Factor_{Zone\ A} = \left(\frac{DFAX_{Zone\ A}}{\sum Negative\ DFAX's}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right) * \boldsymbol{LRS}, if\ DFAX_{Zone\ A}\ is\ (-)$$

(LRS = Load Ratio Share Percentage)

$$\boldsymbol{Reliability\ Project\ Benefit}\ (\$)_{\boldsymbol{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

LODF Approach

$$\sum Positive\ LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}$$, where

Post Contingent Flow > Pre Contingent Flow

$$\sum Negative\ LODF_{Zone\ A} =$$

$$\sum_{Outages\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2} +$$

$$\sum_{Outages\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{Pre\ Contingent\ Flow\ (MW) * 2}$$, where

Pre Contingent Flow > Post Contingent Flow

Post contingent flow (MW) = MW flow on reliability upgrade after contingency

Pre contingent flow (MW) = MW flow on reliability upgrade prior to contingency

LODF Approach

$$\boldsymbol{Allocation\ Factor_{Zone\ A}} = \left(\frac{\sum Positive\ LODF_{Zone\ A}}{\sum Positive\ LODF_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) +$$

$$\left(\frac{\sum Negative\ LODF_{Zone\ A}}{\sum Negative\ LODF_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right)$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)_{Zone\ A}} = Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

System Reconfiguration Approach

$$\sum Positive\ Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} +$$

$$\sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}, \text{where}$$

Post Contingent Flow $>$ Pre Contingent Flow

$$\sum Negative\ Relieved\ MW's_{Zone\ A} =$$

$$\sum_{Branches\ in\ which\ From\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2} +$$

$$\sum_{Branches\ in\ which\ To\ Bus\ is\ Zone\ A} \frac{Post\ Contingent\ Flow\ (MW) - Pre\ Contingent\ Flow(MW)}{2}, \text{where}$$

Pre Contingent Flow $>$ Post Contingent Flow

Post contingent flow (MW) = MW flow on system branch <u>after</u> reliability upgrade is outaged

Pre contingent flow (MW) = MW flow on system branch <u>prior to</u> reliability upgrade being outaged

System Reconfiguration Approach

$$\boldsymbol{Allocation\ Factor}_{\boldsymbol{Zone\ A}} =$$

$$\left(\frac{\sum Positive\ Relieved\ MW's_{Zone\ A}}{\sum Positive\ Relieved\ MW's_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Positive\ Flow}{\sum All\ Hours}\right) +$$

$$\left(\frac{\sum Negative\ Relieved\ MW's_{Zone\ A}}{\sum Negative\ Relieved\ MW's_{All\ Zones}}\right) * \left(\frac{Hours\ with\ Negative\ Flow}{\sum All\ Hours}\right)$$

$$\boldsymbol{Reliability\ Project\ Benefit\ (\$)}_{\boldsymbol{Zone\ A}}$$

$$= Reliability\ Project\ Benefit\ (\$)_{All\ Zones} * Allocation\ Factor_{Zone\ A}$$

DPP Analysis

April 10th, 2014

SPP Southwest Power Pool

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Background

- Required by FERC Order 1000
- Removes federal right of first refusal (ROFR) for the construction of transmission projects from regional tariffs
- SPP will bid out approved transmission projects to qualified participants using the Transmission Owner Selection Process (TOSP)

Pre-Project Selection

- SPP staff shall notify stakeholders of the identified transmission needs
- A transmission planning response window of thirty (30) days
- The information in the DPP must be sufficient to allow SPP staff to evaluate the project

SELECTION PROCESS

Phase 1 – Individual Project Testing

- Projects will move on to Phase 2 for further testing if they meet the following criteria
  - The project must meet the need for which it was submitted and
    - Projects to address economic needs must provide a 1-year B/C ratio greater than 0.9 by reducing the congestion. If the project is a seams project the B/C ratio requirement is .8
    - Policy Projects must allow the utilities to meet the regulatory/statutory mandates and goals. Competing projects will be tested for net APC benefit

Phase 2 – Project Grouping

- Project groupings with the greatest Net APC benefit will move on to the final portfolio per future
- Reliability, policy, and economic projects will be combined into project groupings for each future
- The grouping of projects will be evaluated for redundancies

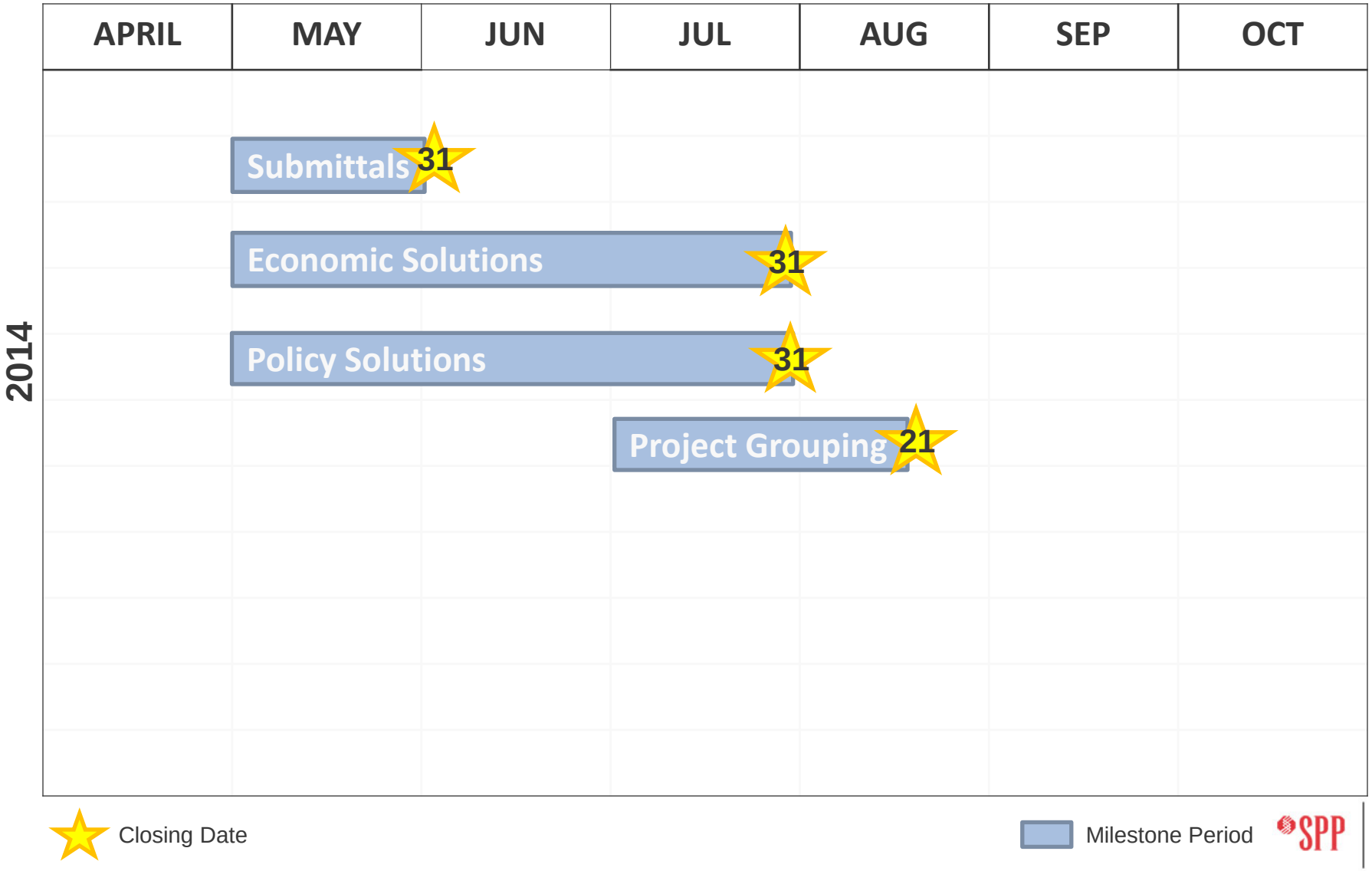
Phase 3 – The Consolidated Portfolio

- The consolidation will be consistent with the Stakeholder approved consolidation methodology

Post Project Selection

- If the project described in a DPP is selected and approved for construction as a Competitive Upgrade, the submitting stakeholder may be eligible to receive incentive points in the bidding process

Timeline

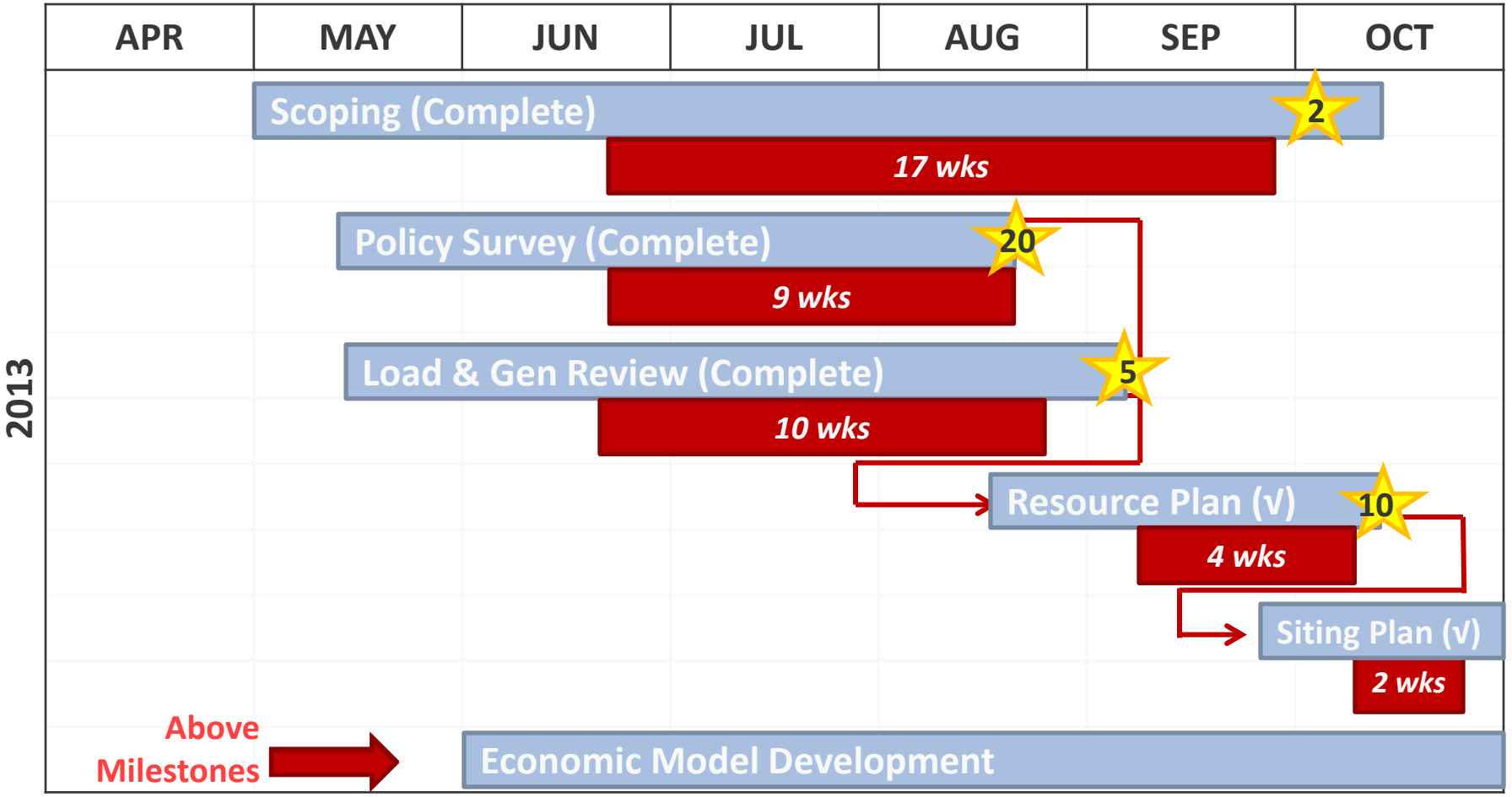

APRIL
MAY
JUN
JUL
AUG
SEP
OCT
2014
Submittals
31
Economic Solutions
31
Policy Solutions
31
Project Grouping
21
Closing Date
Milestone Period

2015 ITP10 Schedule

June 12th, 2014

SPP Southwest Power Pool

ITP10 Milestone Schedule (Apr-Oct 2013)

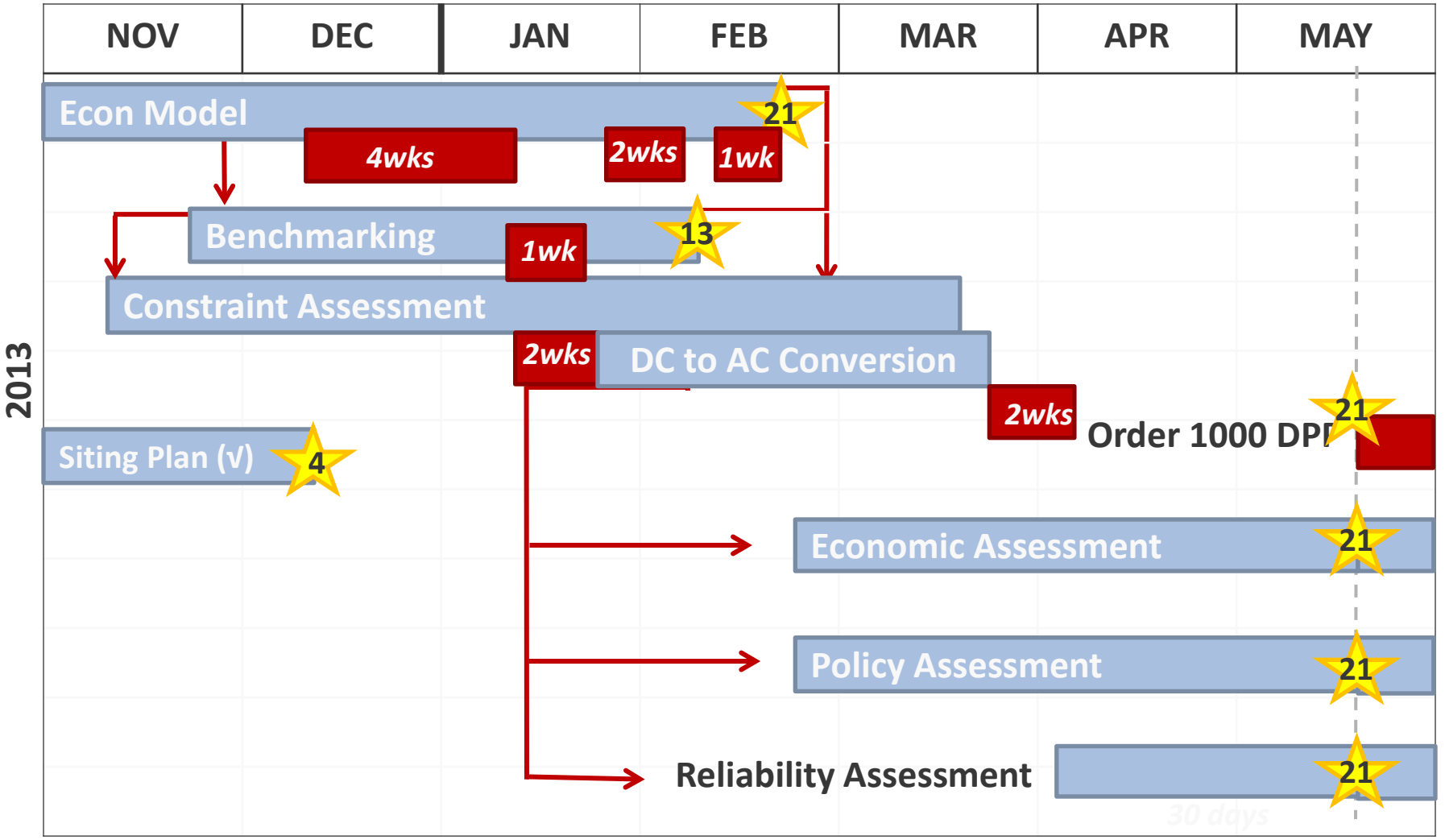


ESWG Approval

Member Review/Feedback Period

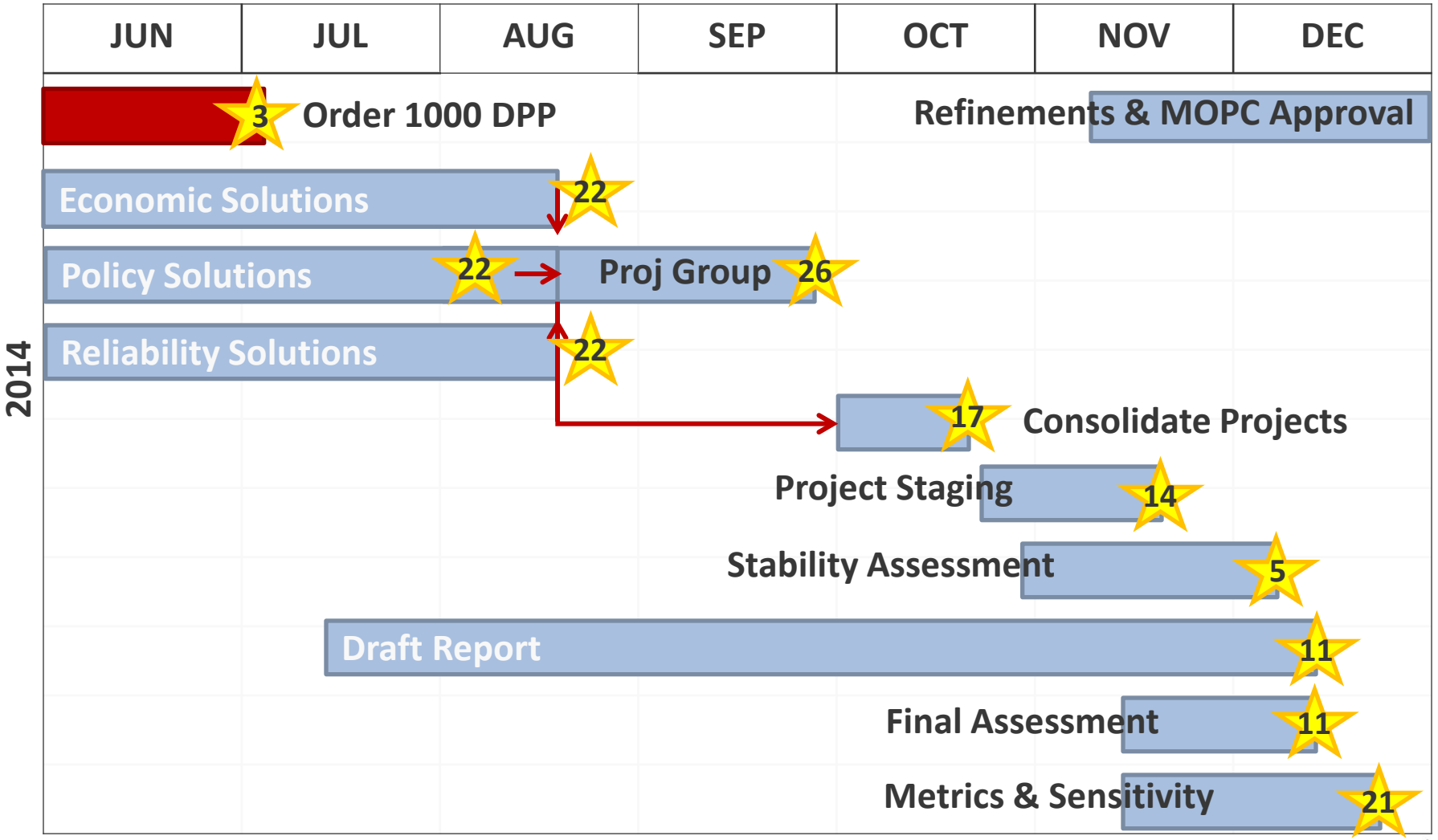
Milestone Period

ITP10 Milestone Schedule (Nov 2013-May 2014)



ESWG Approval | Member Review/Feedback Period | Milestone Period

ITP10 Milestone Schedule (Jun-Dec 2014)



ITP10 Milestone Schedule - Summary

Task Name	Start	Finish	Member Feedback	ESWG Approval	
Scoping	April	October	17 weeks	10/2	
Policy Survey	May	August	9 weeks	12/04	
Load and Generation Review	May	September	10 weeks	9/5	
Resource Plan	August	October	3 weeks	12/04	2013
Siting Plan	September	October	2 weeks	12/04	
Economic Model development	June	February	7 weeks	Feb 21/2014	
Benchmarking	November	January '14	1 week	Feb 13/2014	
Constraint assessment - TWG Approval	November	March '14	1 week		
DC to AC Conversion of Peak Hours	January	March	2 weeks		
Reliability Assessment	March	May	30 days		
Reliability Solutions	May	July		Aug 14/2014	
Economic assessment	February	May	30 days		
Economic Solutions	May	August		Aug 14/2014	
Policy Assessment	May	August	30 days		
Policy Solutions	May	August		Aug 14/2014	
Stability Assessment	October	December			2014
Project Grouping	August	September	1 week	Sep 18/2014	
Consolidate Projects	September	October		Sep 18/2014	
Project Staging	October	November		Nov 13/2014	
Draft Report	July	November	3 weeks	Nov 13/2014	
Final Assessment	November	December		Nov 13/2014	
Benefit Calculation	November	December	3 weeks	Nov 13/2014	
Refinements and MOPC Presentation	November	January '15			

Metrics Review & Recommendations

ESWG

June 12th, 2014

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Agenda

- **Introduction**
- **Assessment of benefit metrics and alternative allocation methodologies**
  A. Benefits of Mandated Reliability Projects
  B. Benefits from Meeting Public Policy Goals
  C. Mitigation of Transmission Outage Costs
  D. Increased Wheeling Through and Out Revenues
  E. Marginal Energy Losses Benefits
- **Timeline & next steps**

Overview

- **ESWG has been tasked with reviewing the calculation and allocation of benefit metrics for:**
  - 2015 ITP10
  - RCAR II
- **MOPC directed ESWG to provide recommendations by July 2010**
- **Brattle is engaged for an independent assessment of alternative methodologies on "tentative metrics"**
- **Today – will discuss pros/cons of alternatives and show preliminary findings on the impact of RCAR I results**

Benefit Metrics

	Benefit Metrics	Calculated in RCAR I?	Considered for 2015 ITP10 and RCAR II?	Included in This Assessment?
	Adjusted Production Cost (APC)	✓	Yes	
	Emission Rates and Values	✓	Yes	
	Ancillary Service Needs and Production Costs	✓	Yes	
	Avoided or Delayed Reliability Projects	✓	Yes	
	Capacity Cost Savings due to Reduced On-Peak Transmission Losses	✓	Yes	
A.	**Benefits of Mandated Reliability Projects**	✓	**Yes**	**Allocation method**
B.	**Benefits from Meeting Public Policy Goals**	✓	**Yes**	**Overall approach**
C.	**Mitigation of Transmission Outage Costs**	✓	**Yes**	**Allocation method**
D.	**Increased Wheeling Through and Out Revenues**		**Yes**	**How to include**
E.	**Marginal Energy Losses Benefits**		**Yes**	**How to include**
	Reducing the Cost of Extreme Events		No	
	Capital Savings due to Reduction of Members' Minimum Required Margin		No	
	Reduced Loss of Load Probability		No	

A. ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

Reliability Benefit Allocation Methodologies

- **Highway/Byway (current methodology)**
  - Allocates assumed benefits of mandated reliability projects in the same manner costs are allocated
- **Distribution Factor (DFAX)**
  - Measures relative usage of Reliability Upgrades by the load of each transmission zone assuming no transmission outages and that each zone is served by all generation in SPP (excluding renewable generation)
- **Line Outage Distribution Factor (LODF)**
  - Measures incremental usage of reliability upgrades under first contingency conditions (i.e., when existing facilities are on outage)
- **System Reconfiguration (SR)**
  - Measures relief on usage of existing facilities after reliability upgrades are added (assuming all else equal to case with upgrades)

Note:
These allocation methodologies do not impact the total reliability benefit of projects.
They only impact the allocation of benefit to zones.

Highway/Byway Methodology

- **Basic assumptions for allocating reliability benefits:**
  - Reliability upgrades ≥ 300 kV provide regional reliability benefits allocated to all zones based on load ratio share (LRS)
  - Reliability upgrades at 100-300 kV provide mostly (2/3) local and some (1/3) regional benefits (based on LRS)
  - Reliability upgrades < 100kV provide local benefits allocated to only the individual zones projects are located in
- **Attractive because it is intuitive, simple to calculate, transparent, and reasonable long-term proxy (next slide)**
- **However:**
  - Incorporates neither actual usage, nor the need for specific upgrade, nor specific reliability benefit of individual projects
  - Does not necessarily capture potentially higher local reliability benefits of highway projects or the potentially higher regional reliability benefits of byway projects

DFAX Methodology

Attempts to calculate incremental flows on reliability upgrades to serve load in each zone

- Uses incremental power flows from all generation in the SPP footprint (excluding renewables, scaled based on their nameplate capacity) to each load zone
- Positive and negative DFAX are first weighted based on share of annual hours with positive and negative flows from PROMOD simulations
- Then normalized to size of each load zone using load ratio shares

Intends to measure the usage of upgrades under normal (N-0) system conditions but:

- Does not consider the reliability needs that triggered these upgrades in the first place (zones using upgrades may not be the ones that initially needed them)
- Many moving parts in implementing the DFAX approach (e.g., generation assumptions) can significantly impact the allocation of estimated benefits
- Incremental flows from all SPP generation to individual load zones (and excluding renewable generation) does not reflect actual usage of upgrade (next slide)

DFAX Methodology (cont'd)

All-generation-to-load zone approach does not accurately capture system use

- Disadvantages zones far from main SPP resources; makes it appear the zone is importing most of its generation from distant resources, thereby relying much more on regional facilities

Excluding renewables from generation-to-load power flow analysis does not capture some of the reliability need

- Analysis to identify reliability needs include at least some renewable generation (e.g., in power flow cases for both for system peak and shoulder period)

Results sensitive to sequence of calculations

- SPP applies Promod shares to DFAX, then normalizes for size of load zone; PJM first normalizes DFAX then applies Promod shares

Applying power flow usage to all hours of the year based on positive and negative flows does not focus on reliability (but same for LODF and SR)

- Reliability need or benefit is not driven by 8,760 hours of both positive and negative flows (as simulated in Promod)
- Hourly usage reflects neither the need for nor the benefit of the upgrade

LODF Methodology

Measures incremental flows shifted onto a reliability upgrade during (first contingency) outages of existing transmission facilities. However:

- Does not reflect need for the reliability upgrades
- Only measures additional "usage" of upgrade during N-1 outages of the existing transmission facilities (i.e., does not consider usage during N-0 conditions)
- Applying usage during N-1 conditions to 8,760 hours of the year is unrealistic and not related to reliability need
- Tends to result in disproportionate allocation of benefits to nearby zones, particularly for high voltage upgrades driven by regional flows
- Substantial effort to calculate (requires power flow evaluation of outage of every existing transmission element), particularly for AC power flow

System Reconfiguration Methodology

Measures incremental flows shifted onto existing system during outage of the reliability upgrade

- Proxy for how much the upgrade reduces flows on the existing system
- Captures benefits of lower-voltage upgrades on immediately neighboring systems
- Computationally much simpler than LODF

However:

- Subject to same limitations as LODF
- Does not reflect need for high-voltage reliability upgrades driven by broad changes in regional power flows (i.e., beyond the load serving needs of the local zone)
- Would disproportionately allocate reliability benefits of high-voltage upgrades to nearby zones
  - High voltage upgrades attract a lot of flows from the nearby existing system even if that system did not need to be upgraded for the purpose of serving zonal load
  - Would burden local zones with integration of new generation that is exported to rest of SPP footprint

Load Ratio Shares

H/B allocates a major portion of reliability benefits based on load ratio share. Even though this does not provide a "technical gauge" on usage, need, or beneficiaries, there are some good reasons to use LRS:

- Load ratio shares (mostly 12-CP or 4-CP, occasionally 1-CP) are routinely used by utilities to allocate company-wide costs to different subsidiaries and different customer classes
- Transmission-related disturbances can be wide-spread; if reliability events result in load shedding, that will often be distributed on a load ratio share
- Most reliability projects ultimately are built to serve load or interconnect generation needed to serve load; larger utilities will require more of that, so load ratio share will be a good long-term proxy
- Even if public policy requirements indirectly trigger reliability upgrades, larger utilities will likely cause more of that
- Part of the transmission system is necessary to support reserve sharing. Zones with higher peak loads will likely get a greater share of reserve sharing benefits
- NERC reliability-related penalties are allocated based on LRS

SPP Recommendations

Use hybrid approach to reflect the different characteristics of higher and lower voltage reliability upgrades

- Load ratio shares (LRS) to allocate reliability benefits of high-voltage transmission upgrades (>300kV)
  - Recognizes broad regional reliability needs, system usage, and broad impact and reliability benefits of highest-voltage (highway) portion of the grid
- System reconfiguration (SR) results to allocate reliability benefits of low-voltage transmission upgrades (<100kV)
  - Recognizes relief to local system provided by low-voltage upgrades without artificially limiting it to single local zones
- Use average of LRS and SR to allocate reliability benefits of medium-voltage upgrades (100-300kV)
  - Recognizes mix of local and regional needs and benefits associated with these facilities

Preliminary Results

Allocation of RCAR I Mandated Reliability Benefits by Project Type

	All Projects				ITP10				Other				Proctor Comprise		
SPP-wide Benefits															
Total	$2.50 billion				$0.73 billion				$1.77 billion						
Analyzed*	$1.98 billion				$0.67 billion				$1.30 billion				$0.67 B	$1.30 B	$1.98 B
Zone	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**ITP10** DFAX	**Other** SR	**TOTAL**
AEP	22.9%	20.0%	22.6%	19.2%	22.2%	17.4%	22.0%	15.5%	23.2%	21.2%	23.0%	21.0%	17.4%	21.0%	19.8%
CUS	0.8%	0.6%	0.0%	0.0%	1.4%	0.8%	0.0%	0.0%	0.4%	0.4%	0.0%	0.0%	0.8%	0.0%	0.3%
EDE	1.2%	1.0%	0.3%	0.5%	2.3%	1.3%	0.0%	0.2%	0.7%	0.8%	0.4%	0.6%	1.3%	0.6%	0.8%
GMO	2.1%	0.9%	0.2%	0.3%	3.8%	1.2%	0.0%	0.1%	1.2%	0.8%	0.3%	0.3%	1.2%	0.3%	0.6%
GRDA	1.4%	1.5%	0.4%	0.4%	1.8%	1.7%	0.2%	0.2%	1.3%	1.4%	0.5%	0.6%	1.7%	0.6%	0.9%
KCPL	3.9%	2.1%	1.8%	1.4%	7.2%	2.2%	0.6%	0.3%	2.2%	2.1%	2.3%	2.0%	2.2%	2.0%	2.0%
LES	1.2%	0.8%	0.2%	0.3%	1.8%	0.9%	0.2%	0.3%	0.9%	0.7%	0.3%	0.3%	0.9%	0.3%	0.5%
MIDW	1.5%	1.4%	1.6%	1.7%	0.8%	0.2%	0.7%	0.7%	1.9%	2.0%	2.0%	2.1%	0.2%	2.1%	1.5%
MKEC	1.6%	1.9%	0.1%	0.0%	2.1%	0.5%	0.1%	0.0%	1.4%	2.5%	0.1%	0.0%	0.5%	0.0%	0.2%
NPPD	4.7%	4.3%	7.2%	6.8%	6.1%	5.3%	14.2%	13.6%	4.0%	3.8%	3.9%	3.5%	5.3%	3.5%	4.1%
OGE	9.5%	12.0%	11.4%	16.1%	13.2%	16.7%	12.2%	24.5%	7.7%	9.7%	11.1%	11.9%	16.7%	11.9%	13.5%
OPPD	2.5%	2.4%	0.1%	0.2%	4.7%	4.1%	0.0%	0.3%	1.5%	1.6%	0.1%	0.1%	4.1%	0.1%	1.4%
SEPC	1.4%	1.3%	3.6%	4.0%	1.0%	0.8%	3.4%	4.1%	1.6%	1.5%	3.7%	4.0%	0.8%	4.0%	2.9%
SPS	19.6%	30.6%	26.2%	23.8%	18.2%	40.5%	32.4%	24.5%	20.3%	25.6%	23.3%	23.4%	40.5%	23.4%	29.1%
WFEC	6.0%	3.3%	5.3%	4.4%	3.0%	3.6%	6.7%	6.1%	7.5%	3.1%	4.6%	3.6%	3.6%	3.6%	3.6%
WR	19.6%	16.0%	18.9%	20.9%	10.4%	2.8%	7.3%	9.4%	24.2%	22.5%	24.5%	26.6%	2.8%	26.6%	18.7%
TOTAL	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Notes:

These results are based on preliminary analysis including approximately 80% of the upgrades.

The allocation factors under DFAX are very sensitive to specific assumptions and implementation of the approach.

Preliminary Results (cont'd)

Allocation of RCAR I Mandated Reliability Benefits by Voltage Level

	All Projects				< 100 kV				100–300 kV				> 300 kV			
SPP-wide Benefits																
Total	$2.50 billion				$0.36 billion				$1.41 billion				$0.72 billion			
Analyzed*	$1.98 billion				$0.26 billion				$1.09 billion				$0.60 billion			
Zone	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**
AEP	22.9%	20.0%	22.6%	19.2%	46.5%	40.0%	47.6%	45.3%	17.4%	16.3%	16.1%	14.6%	22.4%	17.7%	23.8%	16.0%
CUS	0.8%	0.6%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.5%	0.4%	0.0%	0.0%	1.6%	0.8%	0.0%	0.0%
EDE	1.2%	1.0%	0.3%	0.5%	0.0%	1.2%	2.1%	2.9%	0.8%	0.7%	0.0%	0.0%	2.5%	1.4%	0.0%	0.2%
GMO	2.1%	0.9%	0.2%	0.3%	0.0%	0.8%	0.0%	0.1%	1.4%	0.9%	0.3%	0.2%	4.2%	1.1%	0.0%	0.4%
GRDA	1.4%	1.5%	0.4%	0.4%	3.4%	3.7%	1.7%	2.1%	0.7%	0.9%	0.2%	0.2%	2.0%	1.7%	0.3%	0.2%
KCPL	3.9%	2.1%	1.8%	1.4%	0.0%	2.1%	1.4%	0.8%	2.6%	1.6%	1.9%	1.4%	7.9%	2.9%	1.8%	1.7%
LES	1.2%	0.8%	0.2%	0.3%	0.0%	0.4%	0.0%	0.0%	1.1%	0.8%	0.3%	0.4%	2.0%	0.9%	0.2%	0.3%
MIDW	1.5%	1.4%	1.6%	1.7%	0.0%	0.3%	0.0%	0.0%	2.3%	2.4%	2.4%	2.6%	0.8%	0.2%	0.8%	0.7%
MKEC	1.6%	1.9%	0.1%	0.0%	0.0%	0.5%	0.0%	0.0%	2.1%	2.9%	0.1%	0.0%	1.4%	0.5%	0.1%	0.0%
NPPD	4.7%	4.3%	7.2%	6.8%	0.0%	1.6%	0.3%	0.0%	4.8%	4.4%	4.6%	4.2%	6.7%	5.4%	15.3%	14.6%
OGE	9.5%	12.0%	11.4%	16.1%	2.7%	12.4%	14.0%	17.9%	8.4%	8.6%	9.0%	8.6%	14.5%	18.1%	14.9%	29.0%
OPPD	2.5%	2.4%	0.1%	0.2%	0.1%	1.4%	0.1%	0.1%	1.7%	1.8%	0.1%	0.1%	5.1%	4.1%	0.0%	0.3%
SEPC	1.4%	1.3%	3.6%	4.0%	0.0%	0.4%	0.4%	0.2%	1.9%	1.8%	4.6%	4.9%	1.1%	0.8%	3.2%	4.1%
SPS	19.6%	30.6%	26.2%	23.8%	3.1%	9.9%	4.2%	2.9%	27.2%	31.4%	32.6%	33.3%	13.1%	38.2%	24.0%	15.7%
WFEC	6.0%	3.3%	5.3%	4.4%	20.8%	6.3%	11.5%	8.9%	4.0%	2.2%	3.1%	2.3%	3.3%	3.9%	6.5%	6.2%
WR	19.6%	16.0%	18.9%	20.9%	23.5%	18.4%	16.7%	18.8%	23.2%	23.0%	24.7%	27.2%	11.5%	2.2%	9.0%	10.3%
TOTAL	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Notes:

These results are based on preliminary analysis including approximately 80% of the upgrades.

The allocation factors under DFAX are very sensitive to specific assumptions and implementation of the approach.

Preliminary Results (cont'd)

Allocation of RCAR I Mandated Reliability Benefits under Recommended Hybrid Approach

	All Projects	< 100 kV	100–300 kV			> 300 kV
SPP-wide Benefits						
Total	$2.50 billion	$0.36 billion			$1.41 billion	$0.72 billion
Analyzed*	$1.98 billion	$0.26 billion			$1.11 billion	$0.60 billion
Zone	Hybrid Approch	System Reconfig.	SR	LRS	Average of LRS and System Reconfig.	LRS
AEP	23.3%	45.3%	14.6%	22.4%	18.5%	22.4%
CUS	0.9%	0.0%	0.0%	1.6%	0.8%	1.6%
EDE	1.9%	2.9%	0.0%	2.5%	1.3%	2.5%
GMO	2.5%	0.1%	0.2%	4.2%	2.2%	4.2%
GRDA	1.5%	2.1%	0.2%	2.0%	1.1%	2.0%
KCPL	5.1%	0.8%	1.4%	7.9%	4.6%	7.9%
LES	1.3%	0.0%	0.4%	2.0%	1.2%	2.0%
MIDW	1.2%	0.0%	2.6%	0.8%	1.7%	0.8%
MKEC	0.8%	0.0%	0.0%	1.4%	0.7%	1.4%
NPPD	5.1%	0.0%	4.2%	6.7%	5.4%	6.7%
OGE	13.3%	17.9%	8.6%	14.5%	11.5%	14.5%
OPPD	3.0%	0.1%	0.1%	5.1%	2.6%	5.1%
SEPC	2.0%	0.2%	4.9%	1.1%	3.0%	1.1%
SPS	17.3%	2.9%	33.3%	13.1%	23.2%	13.1%
WFEC	3.8%	8.9%	2.3%	3.3%	2.8%	3.3%
WR	16.9%	18.8%	27.2%	11.5%	19.3%	11.5%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: These results are based on preliminary analysis including approximately 80% of the upgrades.

B. BENEFITS FROM MEETING PUBLIC POLICY GOALS

RCAR I Methodology

- **Public policy benefits were set equal to the cost of public policy project**
  - Scope in RCAR I limited to using cost of public policy projects used as a proxy for benefits of being able to meet renewable energy goals
  - Benefits allocated to zones in proportion to each zone's share of unmet renewable energy goals as of June 2010
- **Limitations:**
  - Does not keep track of state(s) in which the mandate/goal drives a specific project
  - Does not recognize public policy benefits of projects other than those classified as "policy-driven" (e.g., Priority Projects)
  - Could substantially understate benefits if the least-cost alternative is to build local wind at less attractive areas

Alternative Methods Considered

	SPP-wide Benefits	Zonal Allocation
Original RCAR I	Set to cost of public policy projects	Based on share of unmet renewable mandates or goals in the region
Alternative 1	Same as in RCAR I	Based on share of unmet renewable mandates or goals only in states driving the public policy projects
Alternative 2a	Equal to total avoided wind investments plus assumed local transmission costs	Equal to each zone's avoided wind investments plus assumed local transmission costs
Alternative 2b	Same as in 2a	Same as in RCAR I

Alternative 1

- **Total benefits are kept the same as in RCAR I**
  - $296M based on present value of 40-yr ATRRs for the public policy projects
- **SPP-wide benefits are then allocated to only <u>zones in which the renewable mandates or goals are driving the public policy projects</u>**
  - New Gentleman – Cherry – Holt 345 kV line is the only project
  - This specific project is driven only by the goals in Nebraska
  - Therefore, the benefits are allocated only to Nebraska entities

	Unmet Renewable Goal* (MWh)	Share of Unmet Renewable Goal (%)	Public Policy Benefit (2013 $million)
NPPD	1,374,534	48%	$143
OPPD	1,470,070	52%	$153
LES	0	0%	$0
Total	**2,844,604**	**100%**	**$296**

* These numbers represent unmet goals in RCAR I report; and not updated based on ITP10 data

Alternatives 2a–2b

- **Benefits reflect avoided wind plant investments plus assumed avoided local transmission costs**
  - Proctor-recommended approach (May 21-22 ESWG meeting)
  - Wind investment benefits achieved by NTC projects allowing SPP members locate resources at more attractive locations
    - Driven by the difference in capacity factors (need fewer MWs in higher-capacity-factor areas to get the same amount of MWhs)
    - Estimated to be **$322 million** based on the same wind capacity factor data as used in the RCAR I report and valuing savings at $1,750/kW (which represents capital cost for wind generation)
    - Zonal shares can be determined either by: **(a)** calculating each zone's avoided costs separately, or **(b)** by allocating the SPP-wide savings based on unmet renewable goals as in RCAR I
  - NTC projects also help avoid the transmission costs to integrate wind resources that would have been built locally
    - Translates to additional benefits of **$941 million** that would have been needed to connect ~5 GW of wind capacity needed after Jun'10 (assuming local transmission costs of $180,000/MW-wind)

Discussion of Alternative Approaches

- **RCAR I approach is very conservative and significantly understates the public policy benefits of NTC projects (as also discussed in the RCAR I report)**
- **Linking benefits and beneficiaries at project level (Alt. 1) could address some of the concerns raised about the RCAR I approach; however it puts even more emphasis on the classification/labeling of individual projects**
- **Calculating costs that would have been incurred to integrate the same amount of wind generation locally (Proctor Alts. 2a–2b) likely a better proxy for overall benefits**
  - Captures public policy benefits provided by the NTC projects as a portfolio and does not rely on whether projects are classified as policy-driven
  - Reliability and public policy benefits are additive as long as there are no less expensive solutions that could have addressed the identified reliability needs

SPP Recommendations

- **Expand estimation of public policy benefit consistent with Alternative 2 (Proctor approach)**
  - More comprehensively captures benefits as avoided costs of meeting public policy goals through more expensive local resources
  - Avoids reliance on project classification and project costs
- **Use Alternative 2a to allocate public policy benefits**
  - Directly links allocation of avoided wind generation investments to zones that benefit from higher capacity factors of more distant regional wind resources
  - Directly assigns benefit of avoided local transmission to zones based on avoided local wind integration needs
- **Obtain ESWG feedback on specific assumptions and calculations**

Preliminary Results

Wind Investment Savings and Avoided Local Transmission Costs

SPP Zone	Wind Generation Build-out Assumed to be Facilitated by the NTC Projects after Jun'10 (by Location)		Wind Capacity Factor	Wind Generation Build-out Assumed to be Facilitated by the NTC Projects after Jun'10 (by Ownership)		Wind Capacity Factor	Wind Generation Build-out without NTC Projects after Jun'10 (by Location & Ownership)		Wind Capacity Factor	Capital Investment Savings on Wind Generation Build-out		Avoided Local Transmission Cost	Total Public Policy Benefits (Avoided Wind Investment plus Local Transmission Cost)	
										Alt. 2a	Alt. 2b	Both Alts. 2a-2b	Alt. 2a	Alt. 2b
	(MW)	(MWh)	(%)	(MW)	(MWh)	(%)	(MW)	(MWh)	(%)	($m)	($m)	($m)	**($m)**	**($m)**
AEPW	0	0	-	509	1,852,421	41.6%	480	1,852,421	44.0%	$0.0	$34.6	$86.5	**$86.5**	**$121.1**
CUS	0	0	-	0	0	-	0	0	-	$0.0	$0.0	$0.0	**$0.0**	**$0.0**
EDE	0	0	-	84	318,322	43.1%	77	254,658	37.6%	$0.0	$6.2	$13.9	**$13.9**	**$20.1**
GMO	356	1,174,989	37.6%	428	1,550,573	41.4%	376	1,240,459	37.6%	$0.0	$30.0	$67.7	**$67.7**	**$97.8**
GRDA	0	0	-	48	175,789	41.8%	53	175,789	37.6%	$9.3	$0.0	$9.6	**$18.9**	**$9.6**
KCPL	0	0	-	720	2,813,629	44.6%	771	2,540,709	37.6%	$88.4	$56.3	$138.7	**$227.1**	**$195.0**
LES	0	0	-	23	90,587	45.0%	23	90,587	44.4%	$0.5	$0.0	$4.2	**$4.7**	**$4.2**
MIDW	267	1,092,958	46.8%	0	0	-	0	0	-	$0.0	$0.0	$0.0	**$0.0**	**$0.0**
MKEC	418	1,812,339	49.5%	104	428,141	47.0%	99	428,141	49.5%	$0.0	$1.4	$17.8	**$17.8**	**$19.1**
NPPD	805	3,239,206	46.0%	344	1,374,532	45.6%	341	1,374,532	46.0%	$0.0	$26.6	$61.5	**$61.5**	**$88.1**
OKGE	1,173	4,226,805	41.1%	1,041	3,856,369	42.3%	1,070	3,856,369	41.1%	$51.3	$67.6	$192.6	**$244.0**	**$260.2**
OPPD	134	520,755	44.4%	369	1,470,069	45.5%	378	1,470,069	44.4%	$14.9	$28.5	$68.0	**$82.9**	**$96.5**
SUNC	438	1,760,447	45.9%	0	0	-	0	0	-	$0.0	$0.0	$0.0	**$0.0**	**$0.0**
SWPS	1,010	3,735,614	42.2%	526	2,027,429	44.0%	548	2,027,429	42.2%	$39.5	$0.0	$98.7	**$138.2**	**$98.7**
WEFA	449	1,694,004	43.1%	231	804,394	39.8%	213	804,394	43.1%	$0.0	$15.6	$38.3	**$38.3**	**$53.9**
WRI	109	393,487	41.3%	731	2,888,347	45.1%	799	2,888,347	41.3%	$117.9	$55.0	$143.8	**$261.6**	**$198.8**
Total	**5,158**	**19,650,605**	**43.5%**	**5,158**	**19,650,604**	**43.5%**	**5,229**	**19,003,905**	**41.5%**	**$321.8**	**$321.8**	**$941.2**	**$1,263.0**	**$1,263.0**

Notes:

[1] These results are based on preliminary analysis and subject to revision.

[2] Wind investment savings valued at $1,750/kW and local transmission costs are assumed to be $180/kW-wind.

[3] Wind build-out considers the 1.25 REC multiplier for the in-state resources located in Missouri.

Preliminary Results (cont'd)

Public Policy Benefits and Allocation Under Alternative Methods

Zone	Public Policy Benefits (2013 $m)				Allocation Factors (%)			
	RCAR I	Alt. 1	Alt. 2a	Alt. 2b	RCAR I	Alt. 1	Alt. 2a	Alt. 2b
AEPW	$32	$0	$86	$121	10.8%	0.0%	6.8%	9.6%
CUS	$0	$0	$0	$0	0.0%	0.0%	0.0%	0.0%
EDE	$6	$0	$14	$20	1.9%	0.0%	1.1%	1.6%
GMO	$28	$0	$68	$98	9.3%	0.0%	5.4%	7.7%
GRDA	$0	$0	$19	$10	0.0%	0.0%	1.5%	0.8%
KCPL	$52	$0	$227	$195	17.5%	0.0%	18.0%	15.4%
LES	$0	$0	$5	$4	0.0%	0.0%	0.4%	0.3%
MIDW	$0	$0	$0	$0	0.0%	0.0%	0.0%	0.0%
MKEC	$1	$0	$18	$19	0.4%	0.0%	1.4%	1.5%
NPPD	$25	$143	$61	$88	8.3%	48.3%	4.9%	7.0%
OKGE	$62	$0	$244	$260	21.0%	0.0%	19.3%	20.6%
OPPD	$26	$153	$83	$96	8.9%	51.7%	6.6%	7.6%
SUNC	$0	$0	$0	$0	0.0%	0.0%	0.0%	0.0%
SWPS	$0	$0	$138	$99	0.0%	0.0%	10.9%	7.8%
WEFA	$14	$0	$38	$54	4.8%	0.0%	3.0%	4.3%
WRI	$51	$0	$262	$199	17.1%	0.0%	20.7%	15.7%
TOTAL	**$296**	**$296**	**$1,263**	**$1,263**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Notes:

[1] These results are based on preliminary analysis and subject to revision.

[2] Benefits under Alternatives 2a–2b assume $1,750/kW for wind capital costs and $180/kW-wind for local transmission costs.

C. MITIGATION OF TRANSMISSION OUTAGE COSTS

Current-Alternative Allocation Approaches

Benefits based on additional APC savings from market simulations that consider a subset of historical transmission outage events

- Compared results for the 2023 study year with and without 732 historical outage events
  - >230kV and ≥5 days; plus >100kV, ≥4 days with high impacts on either contingencies or binding constraints; 11% of all events, 22% of all outage hours
- APC savings are 11.3% higher with outages, resulting in $340 million of incremental benefits for NTC projects in RCAR I

Currently, this benefit is calculated on an SPP-wide basis and allocated to zones based on load ratio share

- Sep'12 MTF report recommended this approach since it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone over the next 10+ years

Two alternative approaches considered to allocate SPP-wide benefits:

- Alt. 1: Apply each zone's share of APC benefits
- Alt. 2: Apply each zone's share of historical outage events

Discussion of Alternative Approaches

Current allocation based on LRS is simple, easy to verify, and does not depend on the particular pattern of historical outages

- But does not factor possible differences in resilience (e.g., it may overstate the allocated benefits of zones that are above-average resilient to transmission outages)

APC savings in an outage-free environment will not be a good indicator of how the additional benefits related to outage costs will be distributed

- Transmission outages can substantially change congestion patterns and distribution of APC savings
- Zones with high APC savings may not realize additional benefits if already resilient
- Zones with negative APC savings would also benefit from increased resilience

Using frequency of historical outages could inform the allocation but would require long-term data

- Outage frequencies by zone can change significantly from year to year
- Number of events does not capture duration, voltage level, or resulting congestion
- Result: High frequency does not necessarily mean “high impact” (and vice versa)
- Preliminary results show shares of outage frequencies similar to LRS

SPP Recommendations

- **Continue to use load-ratio shares to allocate estimated SPP-wide benefit of transmission outage mitigation**
  - Consistent with MTF recommendation
  - Avoids relying on volatile data due to year-to-year changes in outage patterns
- **Periodically review historic transmission outage data and update additional APC savings ratio**
  - RCAR I ratio of 11.3% based on subset of outages may understate full transmission outage mitigation benefit
  - As more historical outage data is accumulated, longer-term distribution of outage events can be reviewed and used to inform benefit allocation (but should distinguish voltage-level and duration of outage events)

Preliminary Results (cont'd)

Alternative Allocation of Transmission Outage Mitigation Benefits

Zone	Outage Benefits (2013 $m)			Allocation Factors (%)		
	Load Ratio	APC Savings	Historical Outages	Load Ratio	APC Savings	Historical Outages
AEPW	$76	$27	$74	22.4%	7.9%	21.6%
CUS	$5	$1	$5	1.6%	0.2%	1.6%
EDE	$9	$1	$13	2.5%	0.2%	3.9%
GMO	$14	$3	$9	4.2%	0.8%	2.8%
GRDA	$7	$1	$7	2.0%	0.3%	1.9%
KCPL	$27	$3	$10	7.9%	0.8%	3.1%
LES	$7	$1	$5	2.0%	0.2%	1.5%
MIDW	$3	$7	$3	0.8%	2.0%	0.9%
MKEC	$5	$5	$7	1.4%	1.4%	2.1%
NPPD	$23	$25	$36	6.7%	7.5%	10.6%
OKGE	$49	$20	$56	14.5%	5.8%	16.5%
OPPD	$17	$4	$11	5.1%	1.1%	3.1%
SUNC	$4	-$1	$7	1.1%	-0.3%	2.1%
SWPS	$44	$218	$54	13.1%	64.2%	15.9%
WEFA	$11	$3	$10	3.3%	0.8%	2.8%
WRI	$39	$24	$32	11.5%	7.1%	9.5%
TOTAL	**$340**	**$340**	**$340**	**100.0%**	**100.0%**	**100.0%**

Note: These results are based on preliminary analysis and subject to revision.

D. INCREASED WHEELING THROUGH AND OUT REVENUES

Increased Wheeling Through and Out Revenues

- **Increased ATC with neighbors can lead to increased through and out transactions which would increase SPP wheeling revenues and offset a portion of total project costs**
  - Schedules 7, 8, 11
  - MW volume of transmission reservations for long-term service will exceed the MWh of energy scheduled, leaving room for additional non-firm exports
- **SPP recommends two complementary approaches to estimate how increased export ATCs affect wheeling service sold**
  - Impact on long-term reservations based on review of long-term firm TSRs enabled by projects
  - Hourly, non-firm transactions based on Promod simulations
  - Allocation based on current revenue sharing method in tariff

Increased Wheeling – Proposed LT Calculation

- **Run First Contingency Incremental Transfer Capacity (FCITC) model to determine change in export ATCs**
  - Sinks defined in zones typical for transmission service requests (TSRs)
  - Base case: 2014 model (without upgrades)
  - Change case: 2014 model (with upgrades)
- **Determine long-term wheeling service (TSRs) that SPP was able to sell due to upgrades and calculate ratio**

$$\frac{Incremental\ LT\ Wheeling\ Service\ Sold}{ATC_{Change\ Case} - ATC_{Base\ Case}}$$

- **Historical ratio to be utilized to determine wheeling MW and revenues for export-ATC changes from new projects in future**
- **Consider reduced ratios (e.g., scaling factors) based on additional analyses for very large future ATC increases**

Increased Wheeling – Proposed Non-Firm Calculation

- **Volume of long-term wheeling service sold will not capture sale of non-firm hourly wheeling service based on short-term market conditions**
- **Propose to modify Promod simulations to capture this type of "economy-energy" export transactions**
  - Promod simulations apply "hurdle rates" (e.g., non-firm hourly wheeling service rate plus market friction) to all market-based export transactions; export contracts with LT wheeling service do not face such hurdles
  - Non-firm hourly exports generate wheeling revenue in addition to the sale of incremental long-term wheeling service
  - Can be estimated in Promod, but need to (1) add definition of export interfaces and non-firm export-ATC values for base and change cases; (2) more carefully model neighboring regions
  - Value additional export MWH at average SPP rate for non-firm hourly wheeling service

E. MARGINAL ENERGY LOSSES BENEFIT

Marginal Energy Losses Benefit

- **Full MWh losses are not reflected in standard production cost simulations (therefore not captured in traditional APC metric)**
- **SPP recommends calculating energy loss savings through post-processing of simulation results as summarized in MTF report**
  - Based on Marginal Loss Revenues
- **The calculation to be performed for each zone**
- **Results not ready yet, but benefits not likely to be very large compared to other metrics**
  - Could even be negative if projects significantly increase regional transfers (which would be subject to higher losses)

TIMELINE & NEXT STEPS