Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 8th, 2016

SPP Corporate Offices – Little Rock, AR

• SUMMARY OF ACTIONS TAKEN •

1. None

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 8th, 2016

SPP Corporate Offices – Little Rock, AR

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

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

There were 24 in-person participants and 85 web conference participants, representing 17 of 17 ESWG members. (Attachment 1 – December 8th, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Chair Alan Myers (ITC) asked for any proxy statements; two proxies were identified. Don Le (NEET) named Eric Burkey (SCMCN) as his proxy and Jody Holland (SCMCN) named Eric Burkey (SCMCN) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – December 8th, 2016 Agenda)

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

Agenda Item 2 – Chronic Operational Issues Criteria

Will Tootle (SPP Staff) reviewed the proposed chronic operational issues criteria with the ESWG, ORWG, and TWG attendees. Stakeholders comments have been captured in the attached redline document. (Attachment 4 – TPITF - Chronic Operational Issues Criteria_v2_Redline_OPPD Comments_rev)

Agenda Item 3 – 2017 ITP10 Study Schedule

Juliano Freitas (SPP) reviewed the 2017 ITP10 schedule with the ESWG and TWG attendees. SPP staff is reviewing results of the as scoped analysis and final assessments and reviewing the draft result of the model update impacts and additional analysis today. SPP staff will be seeking approvals during the upcoming joint conference call. (Attachment 5 – 2017 ITP10 Schedule)

Agenda Item 4 – 2017 ITP10 Update

Agenda Item 4a – Portfolio Consolidation and Project Staging (as Scoped)

Nikki Roberts (SPP Staff) presented the final results of portfolio consolidation and staging of projects based on the criteria to create a CPP (Reduced Carbon) and a non-CPP (Reference Case) portfolio of projects. Minor adjustments were made to the results based on feedback from the November meeting. (Attachment 6 - 2017 ITP10 Scope Portfolio Consolidation and Project Staging)

Agenda Item 4b – Sensitivity Analysis

Liz Gephardt (SPP Staff) reviewed the results of the sensitivity analysis performed on the Reduced Carbon and Reference Case portfolios. SPP staff tested the ability of the two portfolios to respond to high and low demand forecasts, high and low natural gas prices, an increase in wind and additional coal retirements (for the Reduced Carbon portfolio). These sensitivities showed the range in 1-year benefit-to-

cost ratios that would be experienced under each change in assumption. (Attachment 7 – 2017 ITP10 Sensitivity Analysis)

Agenda Item 4c – Benefit Metrics

Amber Greb (SPP Staff) reviewed the results of 40-year benefit metric analysis on the Reduced Carbon portfolio in Future 1 and Reference Case portfolio in Future 3. (Attachment 8 – 2017 ITP10 Benefit Metrics)

Agenda Item 4d – Rate Impacts

Amber Greb (SPP Staff) reviewed the net impact each transmission portfolio would have to the average residential ratepayer in SPP. (Attachment 9 – 2017 ITP10 Rate Impacts)

Agenda Item 4e – Project Recommendations

Agenda Item 4ei – Model Update Impacts

Kelsey Allen (SPP Staff) reviewed the impact that the different model changes had to the congestion on the economic needs and the benefit-to-cost ratios of the Reduced Carbon and Reference Case projects. This included model corrections, wind profile updates, and sidebar model result comparisons to the approved base model. The group just requested that the different data is clearly defined moving forward. (Attachment 10 – 2017 ITP10 Model Update Impacts)

Agenda Item 4eii – Draft Project and Staging Recommendations

Kelsey Allen (SPP Staff) reviewed each of the projects in the two final portfolios and gave SPP staff's draft recommendation on whether the project should be included in a final recommended transmission plan as well as the suggested need date. This included evaluating each project's performance in the Future 1 and Future 3 base and sidebar models, consideration of current operational congestion cost and any other pertinent information. Generally, projects were recommended to move forward if they were shown to be beneficial in both Future 1 and Future 3 models, or one Future model and would resolve current operational issues. Bethany King (EDE) asked about the recommendation of terminal upgrades for the Neosho – Riverton 161 kV line and if a larger project was considered. Kelsey Allen (SPP Staff) stated that the rebuild of the line as well as larger EHV projects were tested but the main focus of the eastern seam analysis was the CUS area, specifically the Brookline transformer and there was no viable projects that could address both issues. In order to allow for the future potential to do more in depth analysis in the area, SPP staff is recommending a small terminal upgrade at this time. (Attachment 11 – 2017 ITP10 Project Recommendations)

Agenda Item 4eiii – Additional Analysis (of Target Areas)

Josh Ross (SPP Staff) began review of the additional analysis performed by SPP staff to develop alternative project recommendations for the eastern seam and Texas panhandle. Josh discussed the projects analyzed to resolve the Brookline transformer constraint and the different sensitivities performed. SPP staff currently has two top candidates, one that would involve potential cost sharing and negotiations with an SPP neighbor company, Associated Electric Cooperative.

Liz Gephardt (SPP Staff) presented the additional analysis performed to develop an alternative project recommendation in the Texas panhandle. This analysis focused on the potential to propose a 345 kV solution from Potter to Tolk substations over rebuild of the 115 kV system. SPP staff focused on uncertainties surrounding the proxy resource plan and the potential to avoid continuing to rebuild the lower voltage system.

(Attachment 12 – 2017 ITP10 Project Recommendations)

Agenda Item 5 – Review of Past Action Items

[This item was not covered in the allotted time]. (Attachment 13 – Past Action Items)

Agenda Item 6 – ESWG Charter

[This item was not covered in the allotted time]. (Attachment 14 – ESWG Charter_rev 11.30)

Agenda Item 7 – ITP Scope Standardization

Agenda Item 7a – Wind Pricing

[This item was not covered in the allotted time]. (Attachment 15 – ITP Wind Pricing)

Agenda Item 7b – Policy Survey

[This item was not covered in the allotted time]

Agenda Item 7c – Phase-Shifting Transformer and DC Line Modeling

[This item was not covered in the allotted time]

Agenda Item 8 – 2017 ESWG Meeting Schedule Update

[This item was not covered in the allotted time]

Agenda Item 9 – Resource Expansion Software Tools Discussion

[This item was not covered in the allotted time]

Closing Items

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

The meeting was adjourned at 2:45 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

December 8, 2016

AEP Office/Dallas, TX

• ATTENDANCE LIST •

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Eric Burkey	SCMCN
Aaron Pupa	LS Power
Gayle Nansel	WAPA-UGP
Adam McKinnie	Mo PSC
Bennie Weeks	Xcel Energy/SPS
Natasha Henderson	ASEC
Bethany King	EDE
Pat McCool	KCPL
Jason Davis	SPP
Kelsey Allen	SPP
Alan Myers	ITC
Amber Grieb	SPP
JULIANO FREITAS	SPP
Tim Owens	NPPD
Leon Howell	OGE
ZAC HAGER	OGE

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

December 8, 2016

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Jim Jacoby	AEP
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Bruce Culé	Xcel Energy / SPS
Jarrod Walford	NTEC

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MO PSC	In Person
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ITC	In Person
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	Webex
SPP	In Person
	Webex
	Webex
	Webex
	Webex
	Webex
Xcel Energy/SPS	In Person
EDE	In Person
NPRB	Webex
	Webex
ABB	Webex
AEP	In Person
AESL	Webex
Xcel Energy/SPS	In Person
	Webex
	Webex
AEP	Webex
AR PSC	Webex
	Webex
	Webex
	Webex
	Webex
	Webex
	Webex
Quanta	Webex
SPP	Webex
	Webex
SCMCN	In Person
WAPA UGP	In Person
	Webex
KCPL	Webex
	Webex
	Webex
	Webex
NTEC	In Person
OCC	Webex
SPP	In Person

	Webex
GDS/ETEC	Webex
	Webex
WR	Webex
BEPC	In Person
SPRM	Webex
AEP	In Person
	Webex
GSEC	Webex
	Webex
SPRM	Webex
	Webex
	Webex
	Webex
KEPCo	Webex
SPRM	Webex
	Webex
	Webex
	Webex
SNC-Lavalin	Webex
	Webex
	Webex
	Webex
SPP	In Person
SPP	In Person
	Webex
	Webex
	Webex
	Webex
	Webex
LES	Webex
OGE	In Person
Cleco	Webex
	Webex
	Webex
	Webex
Texas PUC	Webex
AECC	In Person
	Webex
OMPA	Webex
iTC	In Person
Quanta	Webex
GSEC	In Person
	Webex
KCPL	In Person
	Webex
CUS	Webex

	Webex
	Webex
MRES	Webex
Customized Energy Solutions	Webex
	Webex
	Webex
	Webex
LES	Webex
Wind Coalition	In Person
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Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

November 16-17, 2016

SPP Corporate Office/Little Rock, AR

• ATTENDANCE LIST •

Name	Company
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Josh Ross	SPP
Tim Owens	NPPD
KURT STRADLEY	LES
Jason Davis	SPP
Kirk Hall	SPP
Chris Jamison	SPP
Amber Gregs	SPP
Adam McKinnie	MO PSC
Jeremy Severson	BEPC
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Angie Anderson	SEPC
Eric Burkey	SCMCN
Josephine Degyeft	WAPA
JASON SHOOK	GDS/ETEC
Jarrod Walford	NTEC
AL Tamimi	SEPC

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

November 16-17, 2016

SPP Corporate Office/Little Rock, AR

• ATTENDANCE LIST •

Name	Company
Wayne Penrod	Sunflower
Michael Massery	AECC
Pat McCool	KCPL
Bethany Kily	EDE
Gayle Wansley	WAPA
Leon Howell	OGE

1. **Don Le (NEET) proxy to Eric Burkey (SCMCN)**

From: Le, Don
Sent: Tuesday, December 06, 2016 9:03 PM
To: Eric Burkey; Alan K. Meyers; Kelsey Allen
Subject: **External Email** Proxy for Thursday ESWG Meeting

Gents,

Since I will be unable to attend this week's ESWG meeting, Eric Burkey has my proxy.

Safe travels guys!

Thanks,
Don Le

2. **Jody Holland (SCMCN) proxy to Eric Burkey (SCMCN)**

From: Holland, Jody
Sent: Friday, December 02, 2016 12:18 PM
To: Alan Myers (amyers@itcgreatplains.com); Kelsey Allen
Cc: Eric Burkey
Subject: **External Email** proxy for 12/8 ESWG meeting

Please accept my proxy for Eric Burkey for the 12/8 ESWG meeting. Thanks.

Jody Holland
Director, Transmission Planning
South Central MCN, LLC
Midcontinent MCN, LLC
MidAtlantic MCN, LLC
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ECONOMIC STUDIES WORKING GROUP

December 8th, 2016

8th Floor AEP Offices – Dallas, TX

• A G E N D A •

8:00am – 3:00pm

ESWG/ORWG/TWG Items

1. Administrative Items
    a. Call to Order, Introductions ..... Alan Myers (5 minutes)
    b. Receipt of Proxies ..... Kelsey Allen (1 minute)
    c. Review of Agenda[1] ..... Alan Myers (1 minute)
2. Chronic Operational Issues Criteria[1] ..... SPP Staff (60 minutes)

ESWG/TWG Items

3. 2017 ITP 10 Study Schedule[1] ..... Juliano Freitas (5 minutes)
4. 2017 ITP10 Update ..... SPP Staff (180 minutes)
    a. Portfolio Consolidation and Project Staging[1] (as Scoped)
    b. Sensitivity Analysis[1]
    c. Benefit Metrics[1]
    d. Rate Impacts[1]
    e. Project Recommendations
        i. Model Update Impacts
        ii. Draft Project and Staging Recommendations[1]
        iii. Additional Analysis (of Target Areas)[1]

ESWG Items

5. Review of Past Action Items[1] ..... Kelsey Allen (5 minutes)
6. ESWG Charter[1] ..... Kelsey Allen (5 minutes)
7. ITP Scope Standardization ..... SPP Staff (45 minutes)
    a. Wind Pricing[1] (Josh Ross)
    b. Policy Survey (Liz Gephardt)

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[1] Background Material Included

c. Phase-Shifting Transformer and DC Line Modeling (Kelsey Allen)

8. 2017 ESWG Meeting Schedule Update ..... All (5 minutes)

9. Resource Expansion Software Tools Discussion ..... Juliano Freitas (30 minutes)

10. Closing Items ..... All (5 minutes)
    a. Summary of Action Items (Kelsey Allen)
    b. Future Meetings
        i. December 14th, 2016: Web Conference
        ii. January 5th, 2017: Web Conference
        iii. January 12th, 2017: 8th Floor AEP Offices, Dallas, TX
        iv. March 16th, 2017: 8th Floor AEP Offices, Dallas, TX
        v. April 20th, 2017: 8th Floor AEP Offices, Dallas, TX
        vi. June 15th, 2017: 8th Floor AEP Offices, Dallas, TX

10/6/16

Objective:

The TPITF made several recommendations to the current planning process to improve the identification of projects and process timelines. Per the TPITF white paper recommendation SPP staff has developed strawman criteria in order to identify chronic operational events that need long term transmission solutions proposed. This criteria will be inserted into the ITP Manual. The identification of chronic operational issues will be performed in parallel of ITP process.

The needs identified by this criteria will be deemed either Economic or Reliability and will be included in the normal ITP DPP needs list that is posted. However, the needs identified by this criteria will be evaluated using operational models that captured the actual occurrences of the needs. These operational models will be approved by the applicable SPP stakeholder working groups to ensure consistency with the criteria established to designate the operational needs as chronic, rather than infrequent system needs. ~~For those operational needs that are not mitigated by the proposed set of projects, or other DPPs, SPP Staff will develop candidate projects to address the needs.~~The evaluation criteria that will be used to determine if these operational needs require projects will be described in a separate document. The candidate projects and associated justification will be presented to the TWG, ESWG, and ORWG for their review and endorsement. ~~The list of endorsed projects will be included in the ITP project portfolio that is submitted to the MOPC and the SPP BOD for approval.~~

- Flowgate issues (Economic/Reliability)
  - Flowgates must reference monitored elements under the SPP Tariff. Flowgates congested for at least 20% of the previous 24 months, either in a breached or binding state in the Real-Time Balancing Market solution, will be added to the ITP needs list. Periods of time when a flowgate's related congestion is deemed to be the result of an outage(s) will be excluded. (Economic)
  - Flowgates with congestion costs totaling more than $10 million over the previous twenty four months will also be added to the ITP needs list. Congestion costs will be calculated using the same methodology as the VRL Report process. Periods of time when a flowgate's related congestion is deemed to be the result of an outage(s) will be excluded. (Economic)
  - IROL Flowgates identified in operations shall be added to the needs list. Flowgates congested for at least 20% of the previous 24 months of the SOL, either in a breached or binding state in the Real-Time Balancing Market solution, will be added to the ITP needs list. Periods of time when a flowgate's related congestion is deemed to be the result of an outage(s) will be excluded. (Reliability)

Commented [AG1]: Remove

Commented [AG2]: Comments from the call: there should be criteria on what to include? Possibly remove this line.

Commented [AG3]: Joint Call: Recommends changing to Economic? IROL is captured in the other bullet, remove this section. Provide this an information.

Commented [VJA4]: Should this be Economic instead?

- Congestion cost for outages will be provided for informational purposes.

- High/Low Voltage issues (Reliability)
  - Transmission Operating Guides that require reconfiguration, documenting mitigations for high and low voltage issues, will be reviewed from the last cycle and related voltage issues will be added to the ITP needs list. The mitigation to avoid the high/low voltage issue must be implemented 10% of the time of the year due to non-outage issues. Transmission Operating Guides that will be considered will only include transmission reconfiguration or potential load shed events.
    - Mitigations that are implemented less than 10% of the year, but risk greater than 100 MW of SPP load will also be considered.
- Manual Commitments (Economic)
  - Generation that is dispatched uneconomically in order to support voltage in the local area. Manual commitment events which include startup and extension 25% of the year will be added to the ITP needs list. ~~DPP solutions will be compared against the Make Whole Payments during the cycle as well as expected payments over the next 40 years. Make Whole Payments occurring over the last cycle will be compared to transmission solutions to see if a B/C ratio is greater than .~~

- ~~N-1-1~~Operational Model N-1 Analysis (multiple outage scenarios) (Reliability)
  - The Outage Coordination process will evaluate conflicting outages and prevent overlapping outage from occurring when possible. Rescheduling of outages will be done when it is an available option but unanticipated system issues can occur and this criteria will help to mitigate those scenarios. Operations will identify situations during outages that may result in the loss of load in the event of the next contingency due to a lack of voltage support or lack of transmission sources to serve load. Additional grid resiliency will ensure load is served reliably. In circumstances that risk the loss of load, transmission ~~solutions would be required~~needs will be identified. Load risk issues must be present at least 10% of the year. If there are long term solutions planned for the area then the need for additional support would be excluded.
    - 100 MW of load at risk would be an alternative to not showing up 10% of the time
- Required reconfigurations due to ineffective redispatch (Reliability)
  - Transmission capacity limitations can usually be controlled by flowgates. Applying a threshold to TDFs can leave some transmission paths overloaded with no way to control loading through redispatch. Reconfiguration will relieve the most limiting element, but it often degrades the robustness of the transmission system and increases risk due to the next contingency. The reconfiguration will require an agreed upon Operating Guide that has been implemented in real time 25% of the time of the year.
- Operational Discretion (Economic/ Reliability)

Commented [AG5]: Clarify

Commented [VJA6]: It looks like this was included in the previous version. We think this should probably be kept.

Commented [AG7]: Should we add a dollar value as well in order to capture costs beyond make whole payments? As an either/or

Commented [WT8]: This goes into the process document.

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- Additional needs ~~that require mitgation~~ may be proposed by SPP Operations for issues that do not meet the criteria ~~in other categories~~described above. Additional needs will be identified with discretion for pain points observed in operating the transmission system and presented to ESWG and TWG for review and endorsement.

~~o~~

Project Acceleration:

- Projects that have previously been identified by SPP Planning may be subject to Accelerated Need Dates based on issues identified ~~in Real Time Operations~~per the Chronic Operational Issues Criteria.

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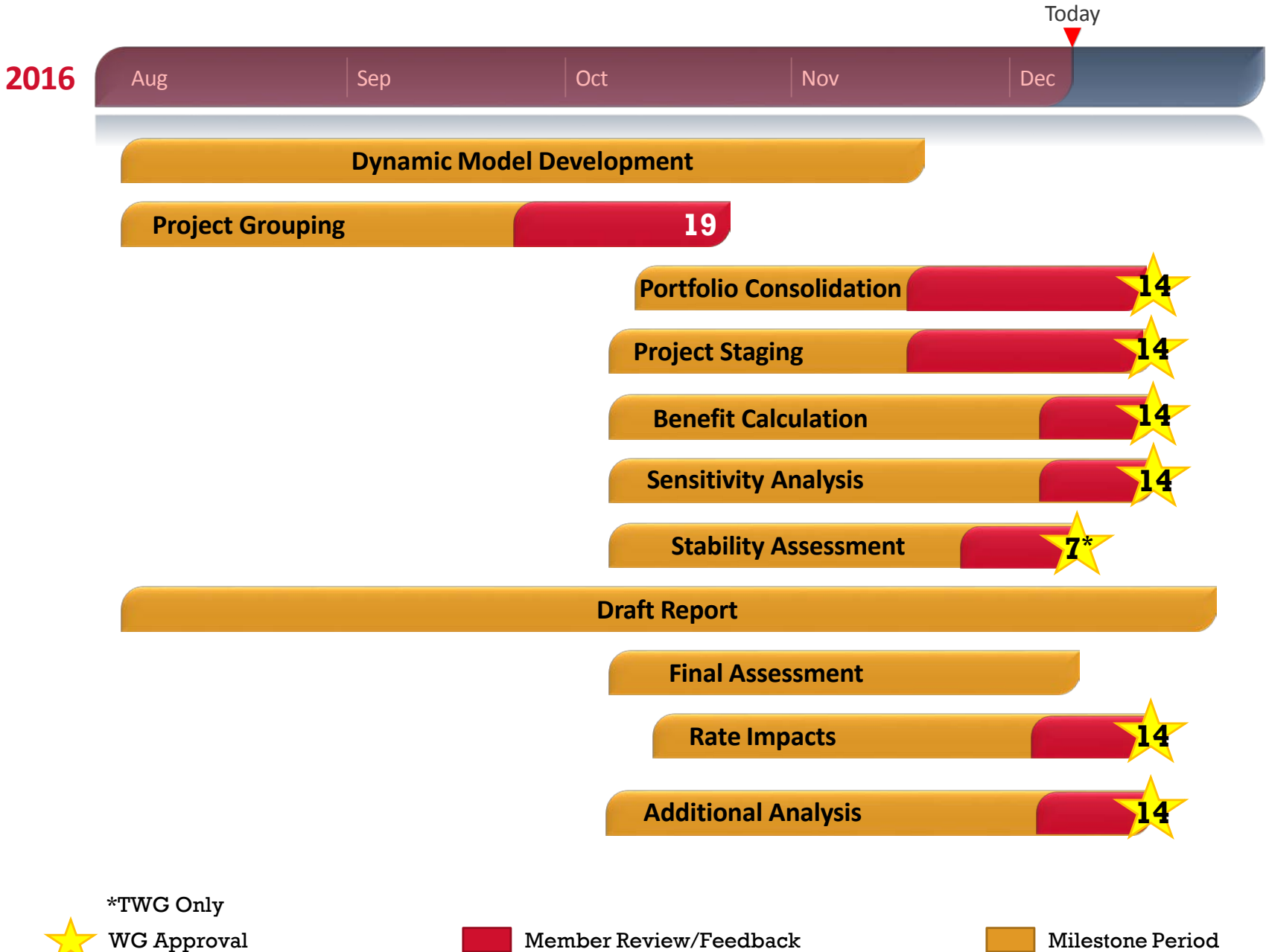
2017 ITP10 Schedule

ESWG

December 8th, 2016


Today
2016
Aug
Sep
Oct
Nov
Dec
2016
Dynamic Model Development
Project Grouping
19
Portfolio Consolidation
14
Project Staging
14
Benefit Calculation
14
Sensitivity Analysis
14
Stability Assessment
7*
Draft Report
Final Assessment
Rate Impacts
14
Additional Analysis
14
*TWG Only
WG Approval
Member Review/Feedback Period
Milestone Period

2017 ITP10 Consolidation and Staging

ESWG

December 8th, 2016

Consolidation of Economic Portfolios

- The ESWG approved 2 final portfolios to be presented to MOPC/BOD:
  - F1 and F2 portfolio projects are to be consolidated into portfolio, the "CPP Portfolio."
  - F3 portfolio projects will stand alone as the Reference Case Portfolio, or "non-CPP Portfolio."

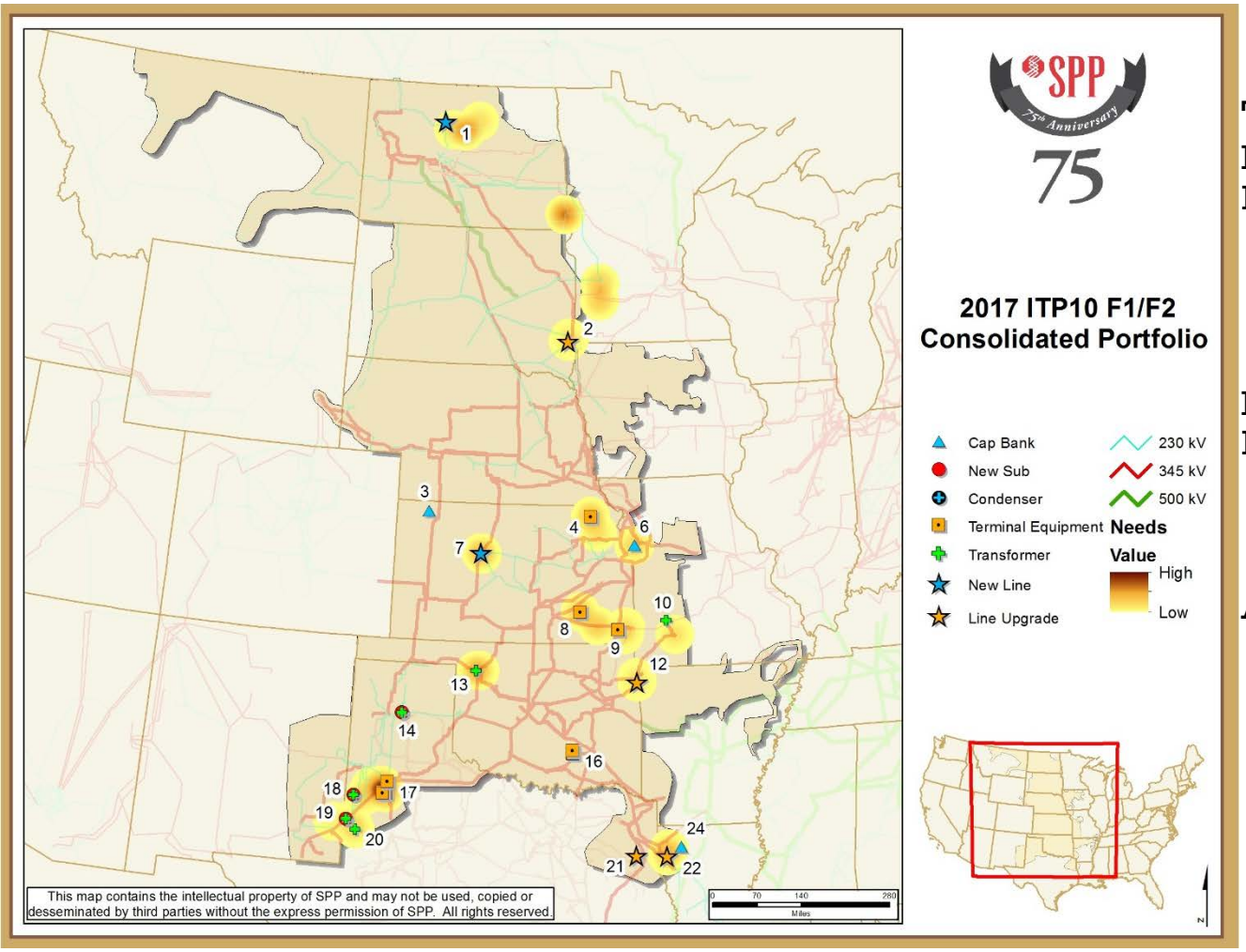
- The F1/F2 Portfolio will consist of projects that meet the 0.9 B/C threshold calculated by taking 75% of the project's benefit in Future 1 and 25% of the project's benefit in Future 2.

- Benefits of economic projects in Futures 1 and 2 were evaluated on the respective future's base case and the F1/F2 Consolidated Reliability portfolio

Staging of Economic Projects

- Incremental benefit of each economic project was calculated for the study and staging years.
- The reference case portfolio benefits were evaluated in Future 3, and the F1/F2 portfolio benefits were evaluated in Futures 1 and 2.
- F1/F2 project benefits were weighted consistent with the Consolidation process (75% in F1, 25% in F2).
- Economic projects given an in-service date for the first year (2020 or later) that the B/C ratio was greater than 1.0 based on interpolation between the staging and study year results.

Consolidated F1/F2 Portfoli



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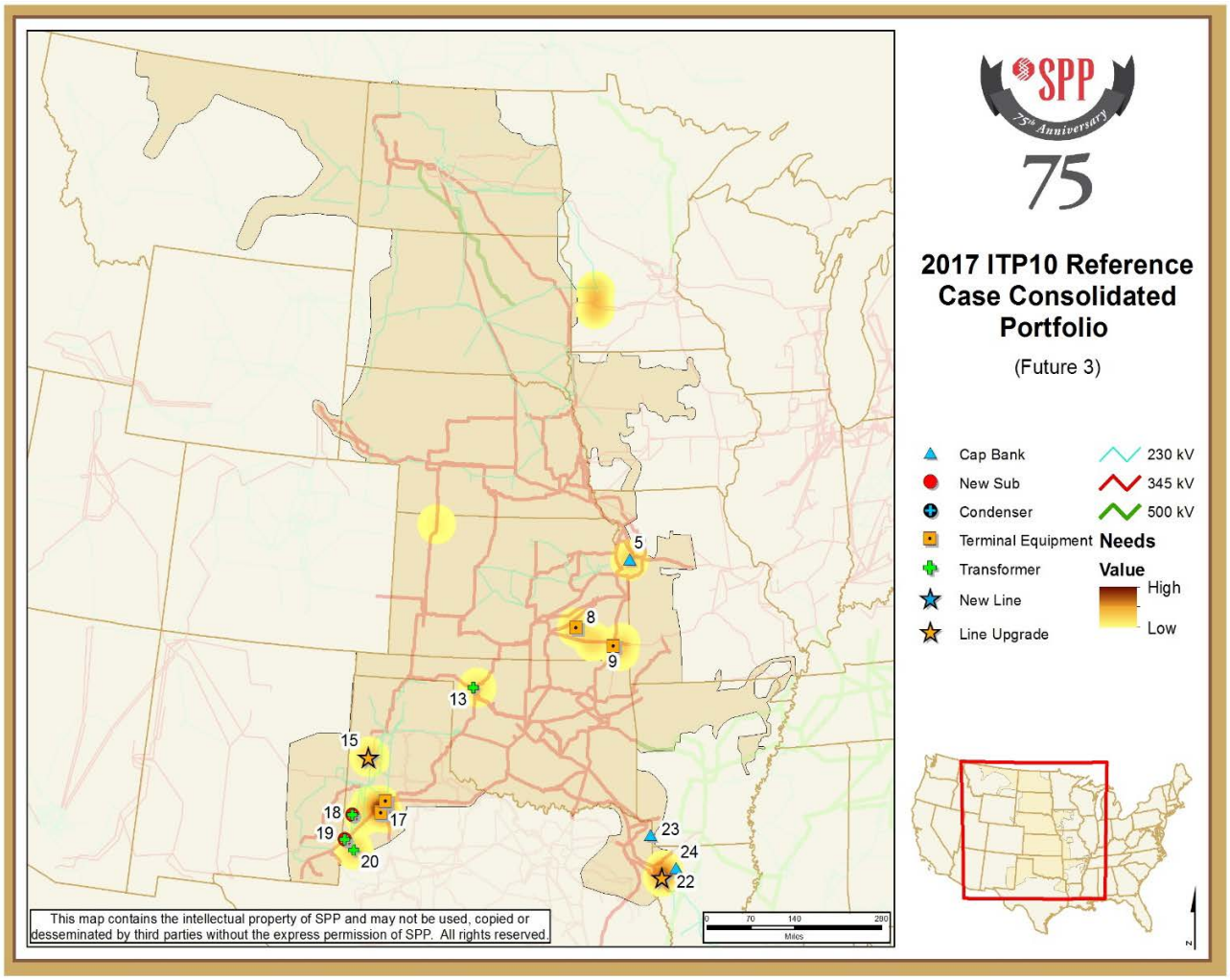
Consolidated F1/F2 Portfolio - Reliability

General Description	Cost Estimate	Location (Zone)	Staging Date
Rebuild 5.5-mile 138kV line from Knox Lee to South Texas Eastman and upgrade any necessary equipment to increase the branch ratings to 371/470 MVA.	$8,456,250	AEP	6/1/2022
Install 28.8-MVAR capacitor bank at Port Robson 138 kV	$2,306,250	AEP	6/1/2025
Install two 14.4-MVAR capacitor banks (28.8 total MVAR) at Atwood 115kV substation. Install 14.4-MVAR capacitor bank at Seguin Tap 115kV substation.	$2,389,707	MIDW	6/1/2024
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$9,953,077	SPS	1/1/2020
Tap the the Nichols to Grapevine 230kV line to construct new substation. Install a new 230/115kV transformer at Nichols - Grapevine tab substation. Construct new 2-mile 115kV line from Martin to Nichols/Grapevine tap substation. Install terminal upgrades at Martin to accommodate new 115kV line from the Nichols/Grapevine tap substation.	$14,936,215	SPS	TBD

Consolidated F1/F2 Portfolio - Economic

General Description	Cost Estimate	Location (Zone)	Staging Year
Install a 345/161 kV transformer at Morgan substation	$8,661,250	AECI	1/1/2020
Rebuild 11.2-mile 138kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	$17,015,000	AEP	1/1/2023
Rebuild 2.1-mile 161kV line from Siloam Springs (AEP)-Siloam Springs City (GRDA) and upgrade terminal equipment at Siloam Springs (AEP) and/or Siloam Springs City (GRDA) to increase the rating of the line between the substations to at least 446/446 (SN/SE)	$5,185,885	AEP/GRDA	1/1/2020
Add 2 ohm Series reactor to Northeast - Charlotte 161 kV line	$512,500	KCPL	1/1/2020
Build a new second 230 kV line from Knoll to Post Rock.	$3,389,019	MIDW	1/1/2020
Install one (1) 138kV phase shifting transformer at Woodward EHV along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	$7,459,438	OGE	1/1/2020
Upgrade any necessary terminal equipment at Tupelo and/or Tupelo Tap to increase the rating of the 161kV line between the two substations to a summer and winter emergency rating of 169/201 MVA.	$102,500	SPA/WFEC	1/1/2020
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115kV line between the two substations to a summer emergency rating of 175 MVA.	$969,942	SPS	1/1/2020
Tap the intersection of the 230kV line from Tolk to Yoakum and the 115kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115kV transformer at new substation.	$11,961,951	SPS	1/1/2020
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	$7,423,880	SPS	1/1/2020
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$9,953,077	SPS	1/1/2020
Build a new double circuit 115 kV line from Magic City to a point on the Logan - Mallard 115 kV line that minimizes the distance between the new substation and the cut-in point. Bisect the Logan - Mallard 115 kV line to cut-in the new double circuit 115 kV line.	$3,075,000	WAPA/XEL	1/1/2021
Rebuild 1.0 mile 115 kV line from Lawrence - Sioux Falls Upgrade terminal equipment at Lawrence and/or Sioux Falls to increase the rating of the line between the substations to 398/398 (SN/SE)	$1,383,750	WAPA/XEL	1/1/2021
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138kV line between the two substations to a summer emergency rating of 110 MVA.	$244,606	WR	1/1/2020
Upgrade any necessary terminal equipment at Kelly and/or Tecumseh to increase the rating of the 161kV line between the two substations to a summer emergency rating of 151 MVA.	$1,550,993	WR	1/1/2021
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line between the two substations to a summer emergency rating of 243 MVA.	$114,154	WR/EDE	1/1/2020

Reference Case Portfolio



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Reference Case Portfolio - Reliability

General Description	Cost Estimate	Location (Zone)	Staging Year
Install 28.8-MVAR capacitor bank at Port Robson 138 kV	$2,306,250	AEP	6/1/2025
Install 28.8-MVAR capacitor bank at IPC 138 kV*	$1,270,836	AEP	1/1/2020
Tap the existing 230kV line from Hobbs to Yoakum and the existing 115kV line from Allred Tap to Waits. Terminate all four end points into new substation. Install 230/115kV transformer at new Hobbs - Yoakum Tap substation.	$9,953,077	SPS	6/1/2020

* - Zonal Reliability Project

Reference Case Portfolio - Economic

General Description	Cost Estimate	Location (Zone)	Staging Year
Rebuild 11.2-mile 138kV line from South Shreveport to Wallace Lake and upgrade any necessary equipment to increase the branch ratings to 371/478 MVA.	$17,015,000	AEP	1/1/2022
Add 1 ohm Series reactor to Northeast - Charlotte 161 kV line	$512,500	KCPL	1/1/2020
Install one (1) 138kV phase shifting transformer at Woodward EHV along with upgrading relay, protective, and metering equipment, and all associated and miscellaneous materials.	$7,459,438	OGE	1/1/2020
Upgrade any necessary terminal equipment at Stanton and/or Tuco to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or Stanton to increase the rating of the 115kV line between the two substations to a summer emergency rating of 154 MVA. Upgrade any necessary terminal equipment at Indiana and/or SP-Erskine to increase the rating of the 115kV line between the two substations to a summer emergency rating of 175 MVA.	$969,942	SPS	1/1/2020
Tap the intersection of the 230kV line from Tolk to Yoakum and the 115kV line from Cochran to Lehman Tap and terminate all four ends into new substation. Install new 230/115kV transformer at new substation.	$11,961,951	SPS	1/1/2020
Replace first existing 230/115 transformer at Seminole. Replace second existing 230/115 transformer at Seminole.	$7,423,880	SPS	1/1/2024
Rebuild 7.12-mile 115kV transmission line from Hereford to DS#6 and upgrade any necessary equipment to increase the summer emergency rating to 240 MVA.	$3,359,671	SPS	1/1/2020
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138kV line between the two substations to a summer emergency rating of 110 MVA.	$244,606	WR	1/1/2020
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line between the two substations to a summer emergency rating of 243 MVA.	$114,154	WR/EDE	1/1/2020

2017 ITP10 Sensitivity Analysis

December 8, 2016

Liz Gephardt

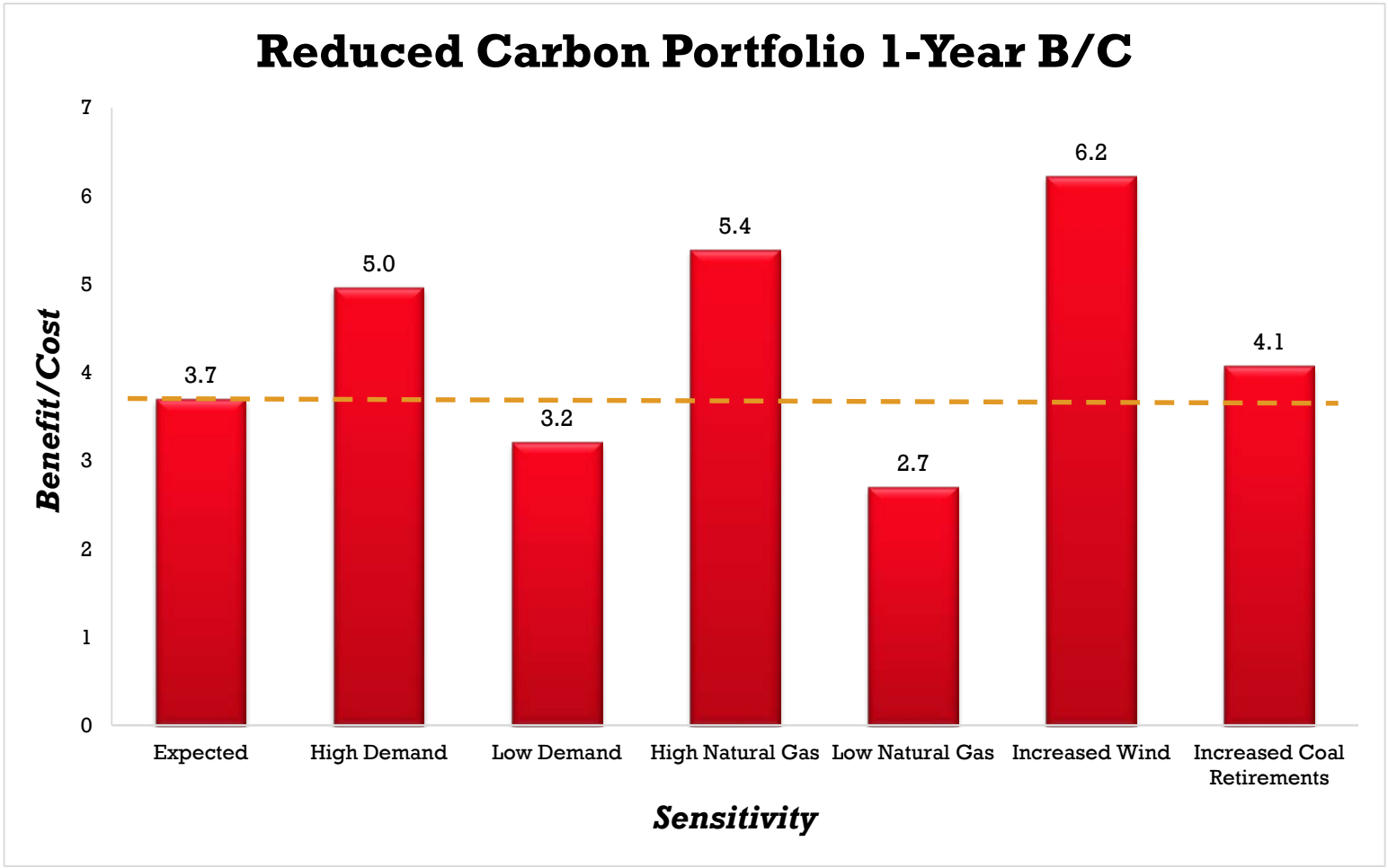
Sensitivity Analysis Overview

- Portfolios are formed based on one set of conditions for of each of the Futures
- Test final portfolios under additional states of the system
  - Scoped Sensitivities
    - High Demand
    - Low Demand
    - High Natural Gas Price
    - Low Natural Gas Price
  - Supplemental Sensitivities
    - Increased Wind
    - Additional Coal Retirements (Reduced Carbon Portfolio only)
- Adjusted Production Cost and 1-year B/C
- Futures Testing
  - Reduced Carbon Portfolio in Future 1
  - Reference Case Portfolio in Future 3
- Does **not** impact final portfolios (Informational only)

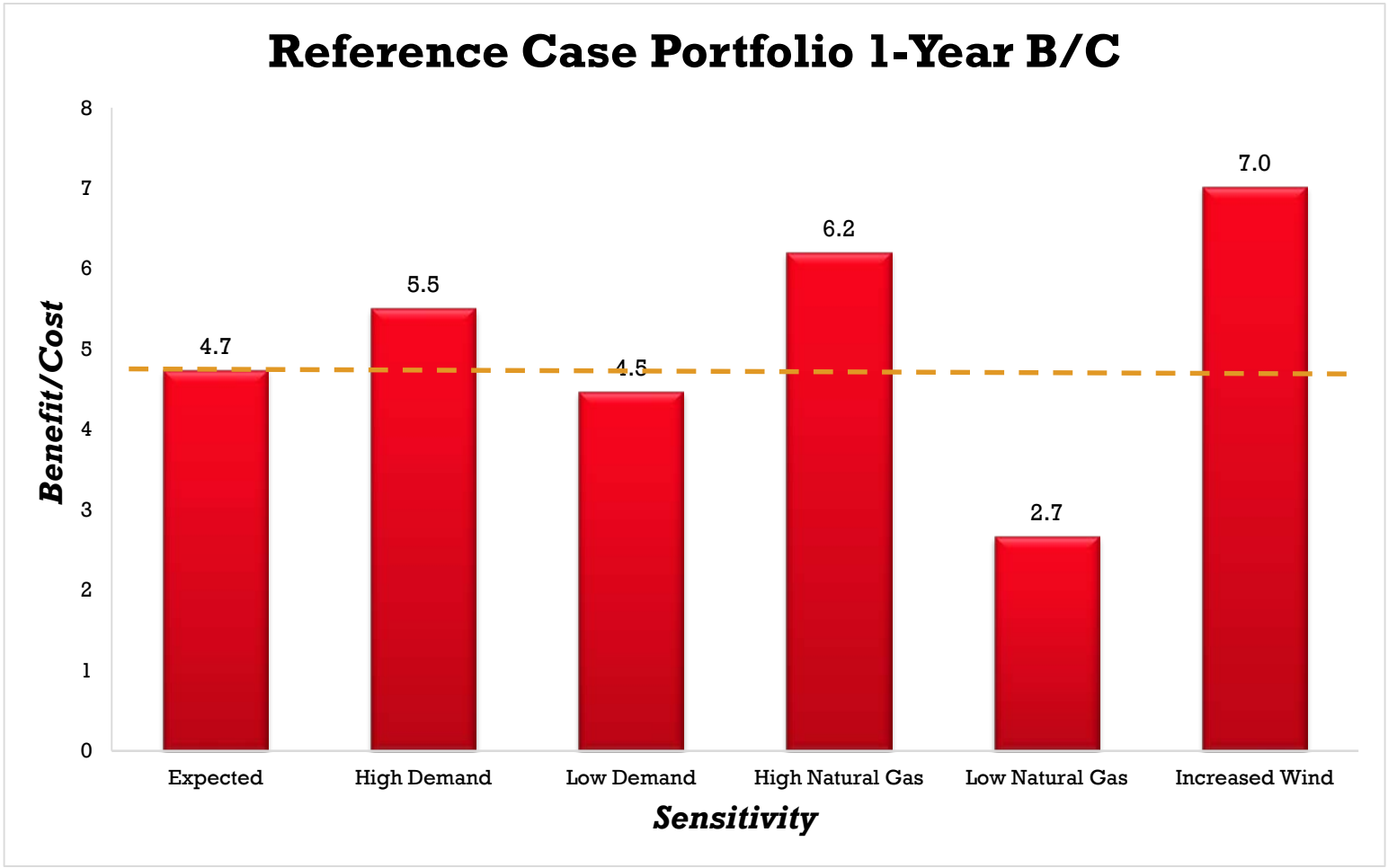
Sensitivity Details

- High/Low Demand
  - 1 standard deviation
  - 67% confidence level
- High/Low Natural Gas Price
  - 2 standard deviation
  - 95% confidence level
- Increased Wind
  - 5 GW incremental wind
  - Scaled existing wind sites up on pro rata basis
- Additional Coal Retirements (Reduced Carbon Portfolio only)
  - Retired coal units excluded for retirement in resource planning phase
  - 10 GW retirements with CC replacements

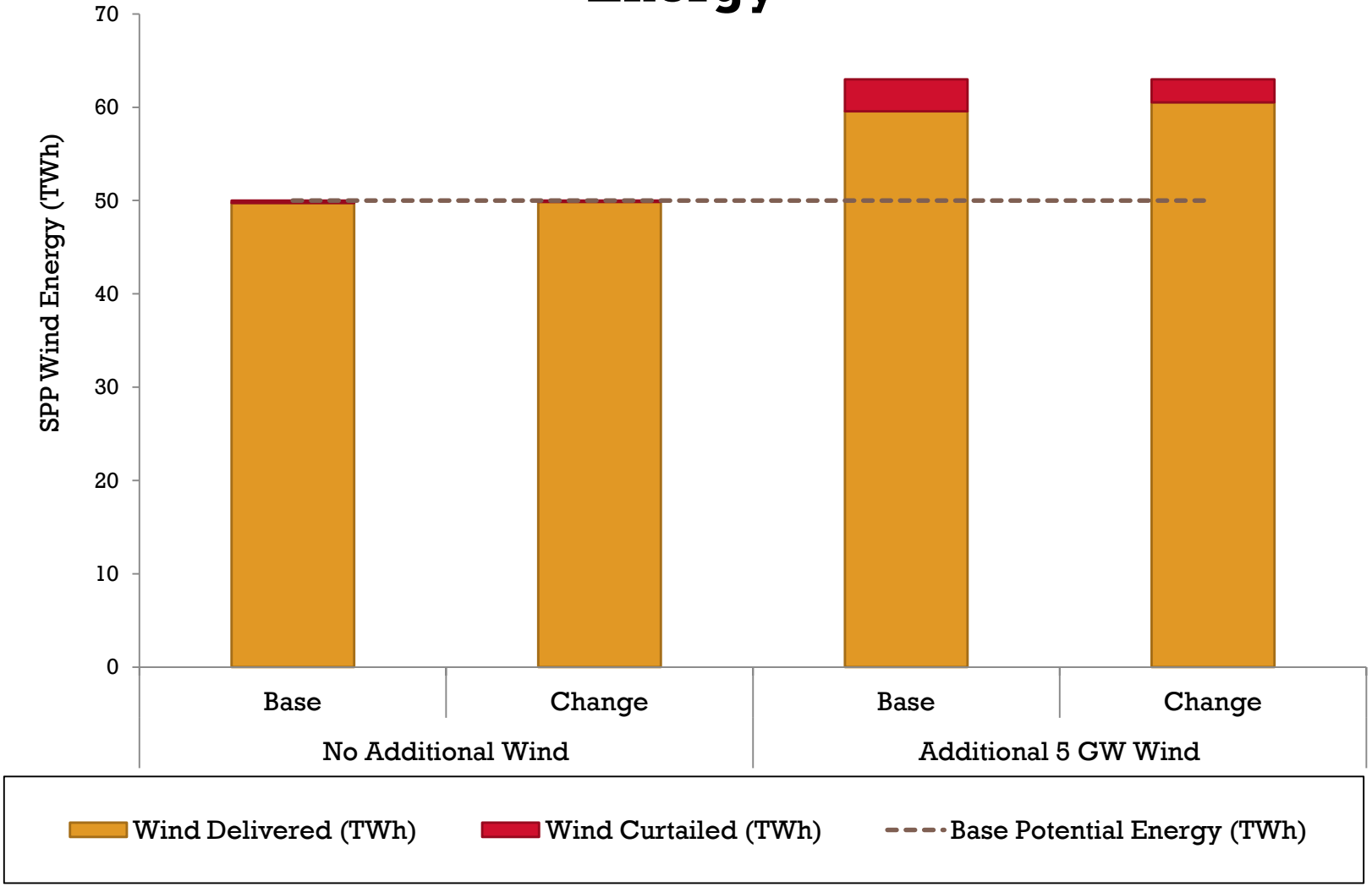
Results


Reduced Carbon Portfolio 1-Year B/C
Benefit/Cost
0
1
2
3
4
5
6
7
3.7
5.0
3.2
5.4
2.7
6.2
4.1
Expected
High Demand
Low Demand
High Natural Gas
Low Natural Gas
Increased Wind
Increased Coal Retirements
Sensitivity

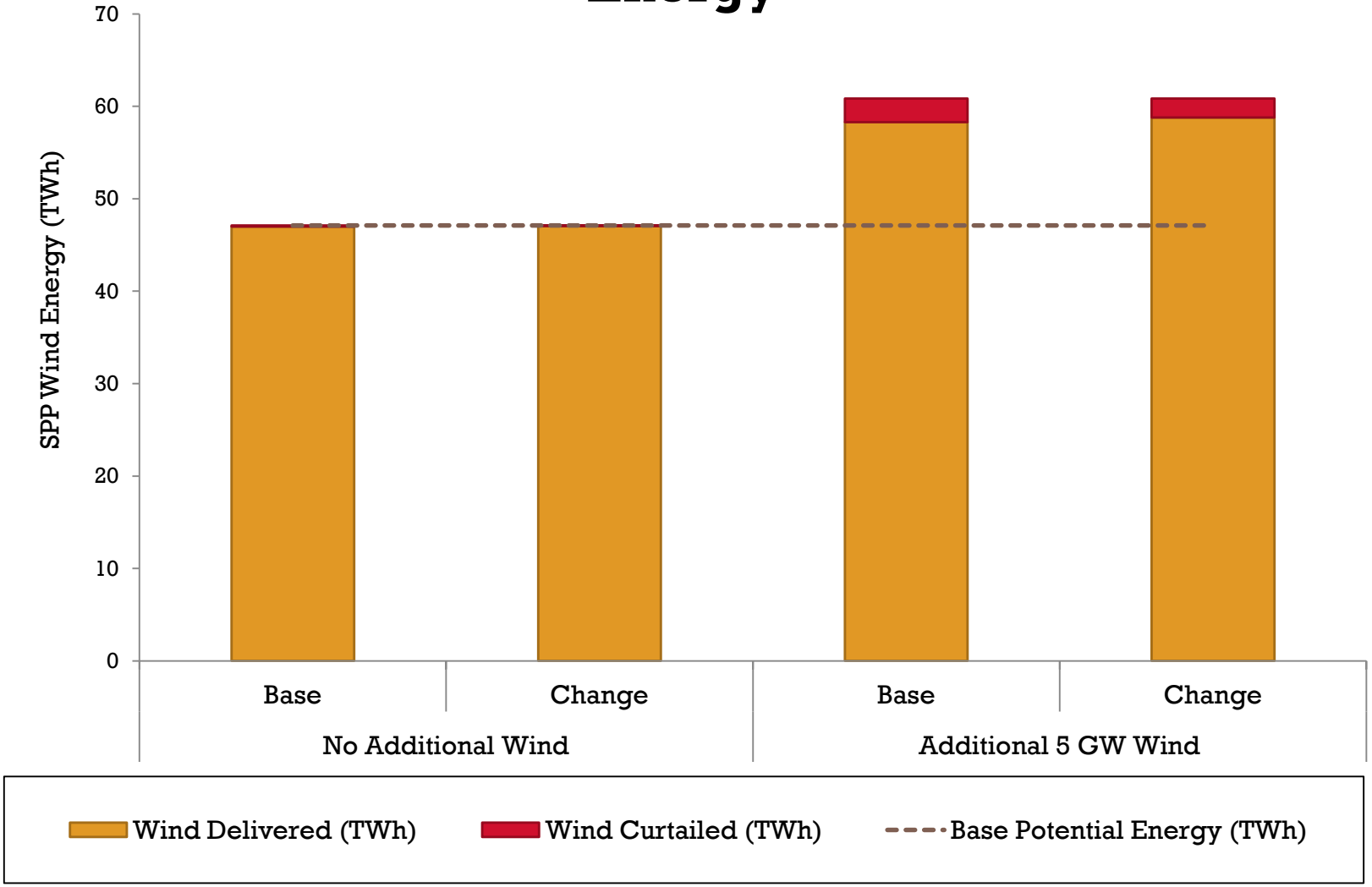
Results


Reference Case Portfolio 1-Year B/C
Benefit/Cost
8
7
6
5
4
3
2
1
0
4.7
5.5
4.5
6.2
2.7
7.0
Expected
High Demand
Low Demand
High Natural Gas
Low Natural Gas
Increased Wind
Sensitivity

Reduced Carbon Portfolio Annual Wind Energy



Reference Case Portfolio Annual Wind Energy



Benefit Metric Results Review

ESWG

Dec 8th, 2016

Benefit Metrics

- Measure the value and economic impacts of the Portfolios
  - Future 1 & 2 Portfolio analyzed in the Future 1
  - Reference Case Portfolio analyzed in Future 3

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

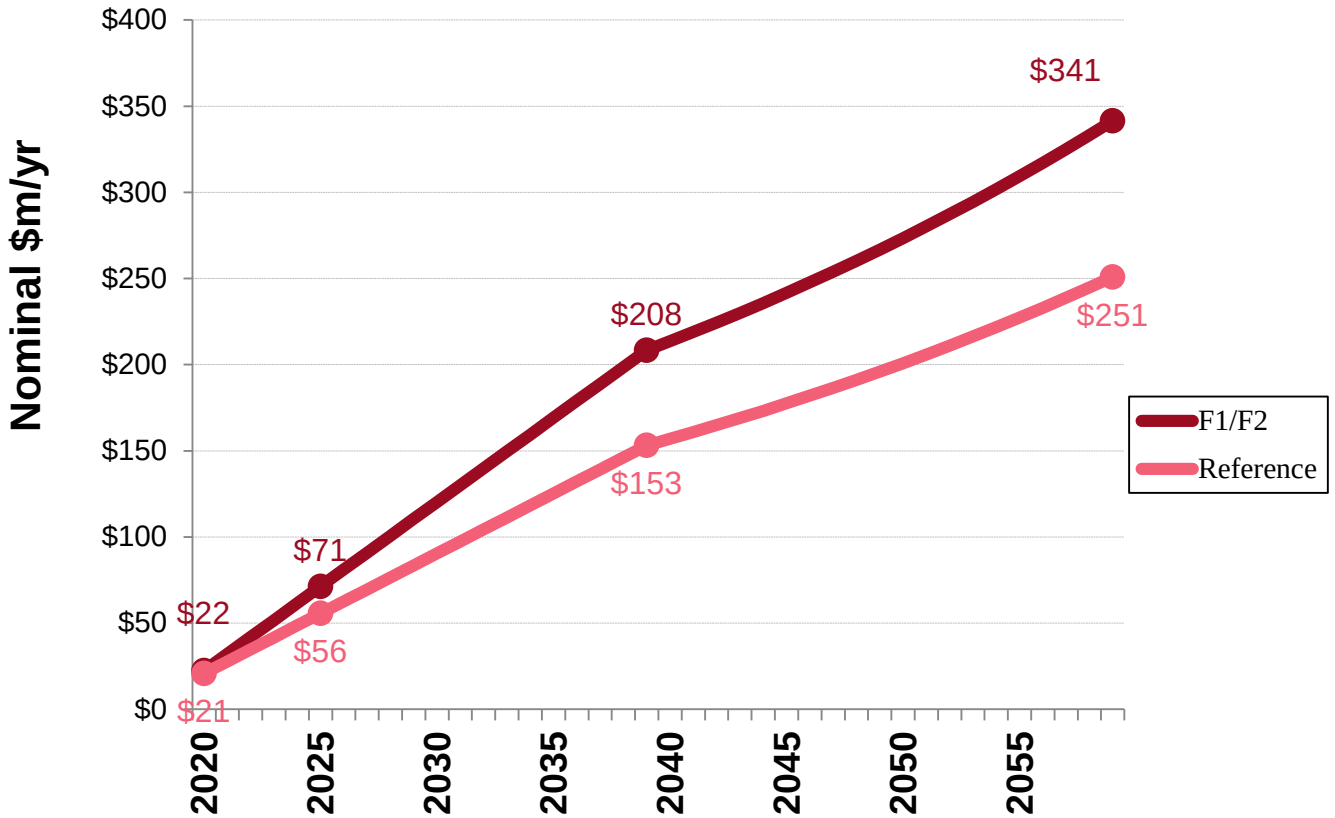
Adjusted Production Cost (APC) Savings

- Monetizes cost savings due to changes in fuel costs, generation dispatch, energy purchases, energy sales, reduction of emissions, and cost of meeting ancillary service needs
  - Considers purchases and sales of energy between each area of the transmission grid
- Calculation is performed by zone on an hourly basis, then summed for the year

APC Savings Results

Zone	F1/F2 Portfolio 2020 ($M)	F1/F2 Portfolio 2025 ($M)	F1/F2 Portfolio 40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	Reference Portfolio 2025 ($M)	Reference Portfolio 40-yr NPV ($2017M)
AEPW	$2.2	$9.6	$202.2	($1.0)	$11.1	$274.9
CUS	$0.4	$2.3	$50.0	($0.1)	$0.1	$3.6
EDE	$0.6	$1.3	$23.8	$1.3	$1.8	$28.7
GMO	$0.3	$0.8	$16.3	($0.3)	($0.1)	$0.5
GRDA	$1.9	$2.7	$43.1	($0.2)	$0.3	$8.1
KCPL	$4.8	$5.6	$79.4	$3.3	$5.4	$91.3
LES	$0.2	($0.1)	($5.7)	$0.2	$0.2	$3.5
MIDW	$0.8	$1.6	$30.0	($0.3)	($0.5)	($8.9)
MKEC	($0.5)	($2.0)	($41.8)	($0.9)	($2.0)	($38.6)
NPPD	$2.5	$2.9	$40.0	$1.3	$2.6	$48.1
OKGE	($1.6)	($0.1)	$15.4	($0.6)	$2.0	$54.7
OPPD	$0.2	($2.0)	($49.8)	($0.0)	($0.6)	($14.6)
SUNC	$0.0	($0.7)	($17.2)	($0.3)	($0.1)	($0.4)
SWPS	$10.1	$24.6	$470.1	$14.9	$25.2	$429.6
IS	($0.1)	$12.2	$289.8	$0.3	($0.5)	($15.1)
WEFA	($0.5)	$10.5	$254.9	$0.0	$7.9	$188.1
WRI	$1.1	$2.2	$40.0	$3.1	$2.9	$32.1
TOTAL	**$22.4**	**$71.3**	**$1,440.5**	**$20.8**	**$55.7**	**$1,085.7**

APC Savings Results



Avoided or Delayed Reliability Projects

- Captures the benefit provided by an economic project by helping to avoid (or delay) a reliability project that would otherwise be needed
- This metric is calculated as follows:
  - Analyze thermal reliability needs in a powerflow model **with and without** the economic projects
  - Identify any thermal reliability needs that are present only in the model without the economic and policy projects
  - Identify projects that would mitigate each of these thermal reliability needs
- This benefit metric monetizes the reliability benefit as the avoided cost of not having to build a separate reliability project
  - Benefit allocated based on each zone's share of costs for the avoided or delayed project

Avoided or Delayed Reliability Projects

Zone	40-yr NPV ($2017M)
AEPW	$0.1
CUS	$0.0
EDE	$0.0
GMO	$0.0
GRDA	$0.0
KCPL	$0.0
IS	$0.0
LES	$0.0
MIDW	$0.0
MKEC	$0.0
NPPD	$0.0
OKGE	$0.1
OPPD	$0.0
SUNC	$0.0
SWPS	$0.9
WEFA	$0.0
WRI	$0.0
TOTAL	**$1.3**

- One Avoided Reliability Project
  - Same for Both Portfolios
  - Terminal Upgrade at Yoakum – Plains
  - Located in SPS

Marginal Energy Losses

- When new transmission results in reduced MWh losses, there is a reduction in energy generated
- This metric captures the reduced production costs associated with this reduction in energy
- These reduced production costs are not reflected in PROMOD simulations
  - Losses aren't simulated
  - Load is "grossed up" to account for losses
  - Production cost savings due to such energy loss reductions can be estimated through post-processing of simulation results
- Calculation is performed by zone on an hourly basis, then summed for the year

Marginal Energy Losses

Zone	F1/F2 Portfolio 2020 ($M)	F1/F2 Portfolio 2025 ($M)	F1/F2 Portfolio 40-yr NPV ($2017M)	Reference Portfolio 2020 ($M)	Reference Portfolio 2025 ($M)	Reference Portfolio 40-yr NPV ($2017M)
AEPW	$1.3	$2.6	$46.1	$0.4	$1.2	$24.5
CUS	$0.3	$0.5	$9.1	$0.0	$0.0	$0.3
EDE	$0.7	$0.8	$10.4	$0.1	($0.1)	($3.2)
GMO	$0.0	$0.0	$0.5	($0.2)	$0.2	$7.6
GRDA	$0.1	$0.1	$1.7	$0.0	$0.1	$1.2
KCPL	($0.3)	($0.1)	$0.4	($0.1)	$0.7	$18.1
LES	$0.0	$0.1	$2.2	($0.1)	$0.2	$5.5
MIDW	$0.0	($0.0)	($0.6)	($0.0)	($0.0)	($0.5)
MKEC	($0.0)	($0.1)	($1.9)	$0.5	$0.0	($4.7)
NPPD	$0.6	$0.7	$8.8	($0.4)	$0.7	$19.8
OKGE	$1.1	$1.5	$23.5	($0.1)	$0.6	$13.9
OPPD	$0.0	$0.1	$0.9	($0.0)	$0.4	$9.0
SUNC	($0.1)	($0.1)	($2.8)	$0.3	($0.1)	($6.1)
SWPS	($2.3)	($2.3)	($27.7)	($0.3)	($3.8)	($83.4)
IS	$0.4	$2.9	$62.6	$0.1	$1.1	$25.6
WEFA	$0.3	$0.4	$6.4	$0.1	$0.2	$4.2
WRI	($1.2)	($2.3)	($40.5)	($0.0)	$0.3	$7.0
TOTAL	**$1.1**	**$4.8**	**$98.9**	**$0.3**	**$1.8**	**$38.9**

Capacity Cost Savings due to Reduced Losses On Peak

- Captures the value for generating capacity that may no longer be required due to a reduction in peak losses
  - Peak MW Losses computed by zone in powerflow models
- This reduction to the installed capacity requirement can be monetized using a Net CONE of **$70/kW-yr** (2017 $) for new generation
  - Net CONE estimated based on cost of constructing a new CT less estimated SPP energy and ancillary service margins
- Metric calculated on a zonal basis

Capacity Cost Savings due to Reduced Losses On Peak

	F1/F2 Portfolio			Reference Portfolio		
Zone	2020 ($M)	2025 ($M)	40-yr NPV ($2017M)	2020 ($M)	2025 ($M)	40-yr NPV ($2017M)
AEPW	$0.1	$0.2	$2.8	$0.1	$0.1	$0.9
CUS	$0.0	$0.0	($0.1)	$0.0	$0.0	$0.0
EDE	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0
GMO	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.1)
GRDA	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0
KCPL	$0.0	$0.0	$0.7	$0.0	$0.0	$0.2
LES	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MIDW	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MKEC	$0.0	$0.0	$0.4	($0.0)	($0.0)	($0.1)
NPPD	($0.0)	$0.0	$0.7	$0.0	($0.0)	($0.3)
OKGE	($0.1)	$0.0	$1.6	($0.1)	$0.1	$2.2
OPPD	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SUNC	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.1
SWPS	$0.2	$0.3	$5.1	$0.2	$0.4	$7.4
IS	$0.0	$0.0	($0.5)	$0.0	$0.0	($0.1)
WEFA	$0.2	$0.2	$1.3	$0.3	$0.1	($0.8)
WRI	$0.0	$0.0	($0.2)	($0.0)	($0.0)	($0.3)
TOTAL	**$0.7**	**$0.9**	**$13.2**	**$0.5**	**$0.6**	**$9.1**

Benefit from Meeting Public Policy Goals

- Monetizes the value of meeting Public Policy requirements
- This metric applies only to projects classified as Policy
  - Does not consider Public Policy benefits associated with economic or reliability projects
  - Since there are currently no Policy projects, the **benefit is $0**

Assumed Benefit of Mandated Reliability Projects

- Monetizes the value of mitigating reliability violations
- The benefit of a mandated reliability project is assumed to be at least equal to the cost, so regional benefit = cost
- Allocation of zonal benefit is based on a hybrid methodology
  - Uses Load Ratio Shares (LRS) and a flow-based approach called System Configuration (SR)

Reliability Upgrade kV	Allocation of Benefit
> 300 kV	1/3 SR, 2/3 LRS
100 - 300 kV	2/3 SR, 1/3 LRS
< 100 kV	100% SR

Assumed Benefit of Mandated Reliability Projects

- System Reconfiguration: Reliability upgrade is removed from the powerflow model and the change in flows on all other facilities are measured
  - Measures the relief that the upgrade is providing to each zone's existing facilities
- Powerflow model results are combined with the results from PROMOD simulations to determine hourly flow direction on upgrades and applied for the weighting

Assumed Benefit of Mandated Reliability Projects – F1/F2 Portfolio

	< 100 kV	100–300 kV			> 300 kV			All Projects	
Total	$0	$28			$0			$28	
Zone	100% SR	66.7% SR	33.3% LRS	Wtd. Avg.	33.3% SR	66.7% LRS	Wtd. Avg.	Hybrid Approach Allocation	Hybrid Approach Benefit
AEPW	0%	19%	21%	20%	0%	21%	14%	19.6%	$6
CUS	0%	2%	1%	2%	0%	1%	1%	1.8%	$1
EDE	0%	3%	2%	3%	0%	2%	2%	2.9%	$1
GMO	0%	0%	4%	1%	0%	4%	2%	1.2%	$0
GRDA	0%	0%	2%	1%	0%	2%	1%	0.6%	$0
KCPL	0%	2%	7%	4%	0%	7%	5%	4.0%	$1
LES	0%	1%	2%	2%	0%	2%	1%	1.6%	$0
MIDW	0%	0%	1%	0%	0%	1%	1%	0.4%	$0
MKEC	0%	0%	1%	0%	0%	1%	1%	0.4%	$0
NPPD	0%	6%	6%	6%	0%	6%	4%	5.8%	$2
OGE	0%	26%	13%	22%	0%	13%	9%	22.0%	$6
OPPD	0%	0%	5%	2%	0%	5%	3%	1.9%	$1
SUNC	0%	0%	1%	1%	0%	1%	1%	0.6%	$0
SWPS	0%	13%	11%	12%	0%	11%	8%	12.4%	$4
UMZ	0%	9%	9%	9%	0%	9%	6%	8.9%	$3
WFEC	0%	11%	3%	9%	0%	3%	2%	8.5%	$2
WR	0%	6%	10%	7%	0%	10%	7%	7.4%	$2
Total	0%	100%	100%	100%	0%	100%	67%	100%	$28

All values in 2017$

Assumed Benefit of Mandated Reliability Projects - Reference Portfolio

	< 100 kV	100–300 kV			> 300 kV			All Projects	
Total	$0	$4			$0			$4	
Zone	100% SR	66.7% SR	33.3% LRS	Wtd. Avg.	33.3% SR	66.7% LRS	Wtd. Avg.	Hybrid Approach Allocation	Hybrid Approach Benefit
AEPW	0%	98%	21%	72%	0%	21%	14%	72.3%	$3
CUS	0%	0%	1%	0%	0%	1%	1%	0.4%	$0
EDE	0%	0%	2%	1%	0%	2%	2%	0.8%	$0
GMO	0%	0%	4%	1%	0%	4%	2%	1.2%	$0
GRDA	0%	0%	2%	1%	0%	2%	1%	0.7%	$0
KCPL	0%	0%	7%	3%	0%	7%	5%	2.6%	$0
LES	0%	0%	2%	1%	0%	2%	1%	0.6%	$0
MIDW	0%	0%	1%	0%	0%	1%	1%	0.3%	$0
MKEC	0%	0%	1%	0%	0%	1%	1%	0.4%	$0
NPPD	0%	0%	6%	2%	0%	6%	4%	2.0%	$0
OGE	0%	0%	13%	4%	0%	13%	9%	4.4%	$0
OPPD	0%	0%	5%	2%	0%	5%	3%	1.6%	$0
SUNC	0%	0%	1%	0%	0%	1%	1%	0.4%	$0
SWPS	0%	0%	11%	4%	0%	11%	8%	3.8%	$0
UMZ	0%	0%	9%	3%	0%	9%	6%	3.0%	$0
WFEC	0%	1%	3%	2%	0%	3%	2%	2.0%	$0
WR	0%	0%	10%	3%	0%	10%	7%	3.4%	$0
Total	0%	100%	100%	100%	0%	100%	67%	100%	$4

All values in 2017$

Mitigation of Transmission Outage Costs

- Metric captures benefit of being able to better mitigate economic harm from transmission outages
- Transmission outages are very common, but APC Savings metric does not capture any transmission outages
- Metric measures incremental increase in APC savings:

Benefit =
(Base APC with outages – Change APC with outages) – ← APC savings with outages
(Base APC without outages – Change APC without outages) ← APC savings without outages

Mitigation of Transmission Outage Costs

Zone	F1/F2 40-yr NPV ($2017M)	Reference 40-yr NPV ($2017M)
AEPW	$33.8	$25.4
CUS	$2.2	$1.6
EDE	$3.7	$2.8
GMO	$6.0	$4.5
GRDA	$2.8	$2.1
KCPL	$11.9	$9.0
LES	$3.0	$2.3
MIDW	$1.3	$1.0
MKEC	$2.1	$1.6
NPPD	$9.7	$7.3
OKGE	$21.4	$16.1
OPPD	$7.7	$5.8
SUNC	$1.4	$1.1
SWPS	$18.6	$14.0
UMZ	$14.6	$11.0
WFEC	$5.5	$4.1
WRI	$16.4	$12.4
TOTAL	**$162.1**	**$122.2**

- Benefit set equal to 11.3% of SPP APC savings benefit
- Benefit is calculated on an SPP-wide basis and allocated to zones based on a load-ratio share

Increased Wheeling Through and Out Revenues

- Increasing ATC with neighboring regions improves import/export opportunities for SPP
  - Can increase through and out transactions that will increase SPP wheeling revenues
  - Wheeling revenues for firm through and out transactions are collected through Schedules 7 and 11
- Increased ATC from new transmission is used to project increased wheeling revenues due to the new transmission
  - Determine long-term wheeling service (TSRs) that SPP was able to sell due to upgrades and calculate ratio:

$$\frac{Incremental\ LT\ Wheeling\ Service\ Sold_{2010-2014}}{ATC_{Change\ Case,2014} - ATC_{Base\ Case,2014}}$$

  - Ratio used to project additional service that can be sold in the future and the associated revenues

Increased Wheeling Through and Out Revenues

Example for 2025 Benefit Calculation:

$$\text{Historical Ratio}_{2014} = \frac{Incremental\ Historical\ TSRs\ Sold\ Thru\ 2014\ (MW)}{ATC_{2014\ Change\ Case}(MW) - ATC_{2014\ Base\ Case}(MW)}$$

↓

$$\text{Forecasted Additional Service Sold}_{2025}\ (MW) = (\text{Historical Ratio}_{2014}) \times (\text{ATC}_{2025\ \text{Change Case}}\ (MW) - \text{ATC}_{2025\ \text{Base Case}}\ (MW))$$

↓

$$\text{Wheeling Benefit}_{2025}\ (\$/yr) = \left[\frac{Incremental\ Wheeling\ Revenues\ Collected\ Thru\ 2014\ \left(\frac{2025\ \$}{yr}\right)}{Incremental\ Historical\ TSRs\ Sold\ Thru\ 2014\ (MW)}\right] \times \text{Forecasted Additional Service Sold}_{2025}\ (MW)$$

Increased Wheeling Through and Out Revenues

	F1/F2 Portfolio			Reference Portfolio		
Zone	2020 ($M)	2025 ($M)	40-yr NPV ($2017M)	2020 ($M)	2025 ($M)	40-yr NPV ($2017M)
AEPW	$0.0	$0.0	$0.0	$0.1	$0.0	$0.3
CUS	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
EDE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
GMO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
GRDA	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
KCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
LES	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MIDW	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MKEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NPPD	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
OKGE	$0.0	$0.0	$0.0	$0.1	$0.0	$0.1
OPPD	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SUNC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SWPS	$0.0	$0.0	$0.0	$0.1	$0.0	$0.3
IS	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
WEFA	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
WRI	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
TOTAL	**$0.0**	**$0.0**	**$0.0**	**$0.5**	**$0.0**	**$1.2**

Summary

Summary of Benefits and Costs – F1/F2 Portfolio

Present Value of 40-yr Benefits for 2020-2059												
Zone	APC Savings (2017 $M)	Avoided or Delayed Reliability Projects (2017 $M)	Capacity Savings from Reduced On-peak (2017 $M)	Assumed Benefit of Mandated Reliability Projects (2017 $M)	Benefit from Meeting Public Policy (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Increased Wheeling Through and Out Revenues (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. Benefit/ Cost Ratio
AEPW	$202	$0	$3	$6	$0	$34	$0	$46	$291	$41	$249	7.05
CUS	$50	$0	($0)	$1	$0	$2	$0	$9	$62	$1	$61	78.38
EDE	$24	$0	$0	$1	$0	$4	$0	$10	$39	$1	$38	29.00
GMO	$16	$0	$1	$0	$0	$6	$0	$1	$24	$2	$22	10.84
GRDA	$43	$0	$0	$0	$0	$3	$0	$2	$48	$6	$42	8.36
KCPL	$79	$0	$1	$1	$0	$12	$0	$0	$94	$5	$89	19.16
LES	($6)	$0	$0	$0	$0	$3	$0	$2	($0)	$1	($1)	(0.03)
MIDW	$30	$0	$0	$0	$0	$1	$0	($1)	$31	$6	$25	5.14
MKEC	($42)	$0	$0	$0	$0	$2	$0	($2)	($41)	$1	($42)	(54.50)
NPPD	$40	$0	$1	$2	$0	$10	$0	$9	$61	$4	$57	17.36
OKGE	$15	$0	$2	$6	$0	$21	$0	$23	$68	$14	$54	4.83
OPPD	($50)	$0	$0	$1	$0	$8	$0	$1	($41)	$3	($44)	(14.67)
SUNC	($17)	$0	$0	$0	$0	$1	$0	($3)	($18)	$1	($19)	(35.61)
SWPS	$470	$1	$5	$4	$0	$19	$0	($28)	$471	$45	$426	10.57
IS	$290	$0	($0)	$3	$0	$15	$0	$63	$369	$12	$357	31.56
WEFA	$255	$0	$1	$2	$0	$6	$0	$6	$271	$2	$268	124.51
WRI	$40	$0	($0)	$2	$0	$16	$0	($41)	$18	$8	$10	2.23
TOTAL	**$1,441**	**$1**	**$13**	**$28**	**$0**	**$162**	**$0**	**$99**	**$1,744**	**$151**	**$1,593**	**11.53**

Summary of Benefits and Costs – Reference Case Portfolio

	Present Value of 40-yr Benefits for 2020-2059											
Zone	APC Savings (2017 $M)	Avoided or Delayed Reliability Projects (2017 $M)	Capacity Savings from Reduced On-peak (2017 $M)	Assumed Benefit of Mandated Reliability Projects (2017 $M)	Benefit from Meeting Public Policy (2017 $M)	Mitigation of Trans-mission Outage Costs (2017 $M)	Increased Wheeling Through and Out Revenues (2017 $M)	Marginal Energy Losses Benefits (2017 $M)	Total Benefits (2017 $M)	NPV 40-yr ATRRs (2017 $M)	Net Benefit (2017 $M)	Est. Benefit/ Cost Ratio
AEPW	$275	$0	$1	$3	$0	$25	$0	$25	$329	$25	$304	13.04
CUS	$4	$0	$0	$0	$0	$2	$0	$0	$6	$0	$5	15.46
EDE	$29	$0	$0	$0	$0	$3	$0	($3)	$28	$1	$28	45.74
GMO	$0	$0	($0)	$0	$0	$5	$0	$8	$13	$1	$12	12.48
GRDA	$8	$0	$0	$0	$0	$2	$0	$1	$11	$0	$11	24.23
KCPL	$91	$0	$0	$0	$0	$9	$0	$18	$119	$3	$116	46.59
LES	$4	$0	$0	$0	$0	$2	$0	$5	$11	$1	$11	22.42
MIDW	($9)	$0	$0	$0	$0	$1	$0	($0)	($8)	$0	($9)	(38.61)
MKEC	($39)	$0	($0)	$0	$0	$2	$0	($5)	($42)	$0	($42)	(120.20)
NPPD	$48	$0	($0)	$0	$0	$7	$0	$20	$75	$2	$73	46.41
OKGE	$55	$0	$2	$0	$0	$16	$0	$14	$87	$10	$77	8.79
OPPD	($15)	$0	$0	$0	$0	$6	$0	$9	$0	$1	($1)	0.21
SUNC	($0)	$0	$0	$0	$0	$1	$0	($6)	($5)	$0	($5)	(22.02)
SWPS	$430	$1	$7	$0	$0	$14	$0	($83)	$369	$31	$338	11.82
IS	($15)	$0	($0)	$0	$0	$11	$0	$26	$22	$2	$19	8.85
WEFA	$188	$0	($1)	$0	$0	$4	$0	$4	$196	$1	$195	213.04
WRI	$32	$0	($0)	$0	$0	$12	$0	$7	$51	$3	$48	16.52
TOTAL	**$1,086**	**$1**	**$9**	**$4**	**$0**	**$122**	**$1**	**$39**	**$1,262**	**$82**	**$1,180**	**15.38**

Rate Impacts

ESWG

Dec 8th, 2016

Rate Impacts

- Measure the rate impacts to average residential ratepayer in SPP
  - Utilized benefits and costs for the 2025 study year
  - APC Savings are the only benefit included
  - Based on an estimated consumption of 1,000 kWh per month

Rate Impacts – F1/F2

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact - Costs	Rate Impact - Benefit	Net Impact
AEPW	$3,070	$6,433	$0.07	$0.15	($0.08)
CUS	$59	$1,559	$0.02	$0.57	($0.55)
EDE	$100	$860	$0.02	$0.20	($0.18)
GMO	$163	$564	$0.03	$0.09	($0.06)
GRDA	$423	$1,828	$0.08	$0.35	($0.27)
KCPL	$363	$3,779	$0.03	$0.27	($0.25)
LES	$82	($83)	$0.02	($0.03)	$0.05
MIDW	$397	$1,095	$0.22	$0.62	($0.39)
MKEC	$56	($1,340)	$0.02	($0.45)	$0.47
NPPD	$261	$1,929	$0.02	$0.14	($0.12)
OKGE	$1,045	($71)	$0.04	($0.00)	$0.04
OPPD	$207	($1,343)	$0.02	($0.13)	$0.15
SUNC	$38	($485)	$0.02	($0.19)	$0.21
SWPS	$3,273	$16,567	$0.09	$0.45	($0.36)
IS	$860	$8,202	$0.03	$0.30	($0.27)
WEFA	$161	$7,061	$0.02	$0.98	($0.96)
WRI	$594	$1,488	$0.03	$0.06	($0.04)
TOTAL	**$11,151**	**$48,044**	**$0.05**	**$0.21**	**($0.16)**

All values in 2017$

Rate Impacts – Reference Case

Zone	One-Year ATRR Costs	One-Year Benefit	Rate Impact - Costs	Rate Impact - Benefit	Net Impact
AEPW	$1,858	$7,496	$0.04	$0.18	($0.13)
CUS	$27	$82	$0.01	$0.03	($0.02)
EDE	$46	$1,237	$0.01	$0.29	($0.28)
GMO	$74	($92)	$0.01	($0.01)	$0.03
GRDA	$35	$174	$0.01	$0.03	($0.03)
KCPL	$188	$3,652	$0.01	$0.26	($0.25)
LES	$37	$161	$0.01	$0.05	($0.04)
MIDW	$16	($340)	$0.01	($0.19)	$0.20
MKEC	$26	($1,370)	$0.01	($0.46)	$0.47
NPPD	$119	$1,768	$0.01	$0.13	($0.12)
OKGE	$730	$1,376	$0.03	$0.05	($0.02)
OPPD	$94	($426)	$0.01	($0.04)	$0.05
SUNC	$17	($100)	$0.01	($0.04)	$0.05
SWPS	$2,290	$16,953	$0.06	$0.47	($0.40)
IS	$180	($344)	$0.01	($0.01)	$0.02
WEFA	$68	$5,339	$0.01	$0.74	($0.73)
WRI	$229	$1,920	$0.01	$0.08	($0.07)
TOTAL	**$6,032**	**$37,487**	**$0.03**	**$0.16**	**($0.14)**

All values in 2017$

2017 ITP10
Model Update Impacts

2017 ITP10

Constraint Congestion Comparison

2017 ITP10 Model Update Impacts

Future 1 Congestion Scores

F1 Constraints	Constraint Source	Existing ITP10 model		BASE CONG Score with Wind Profile Update	Side Bar BASE CONG Score
		BASE CONG Score without model corrections	BASE CONG Score with model corrections		
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	ITP10	$ 781,727	$ -	$ 778,264	$ -
B:661008BEULAH 7 661018COYOTE 7 1 FLO CENTER 4-MANDAN 4 230[1]	ITP10	$ 675,574	$ -	$ 680,072	$ -
B:620327HANKSON4 620329WAHPETN4 1 FLO BUFFALO3-JAMESTN3 345[1]	ITP10	$ 538,715	$ 651,961	$ 547,124	$ 441,081
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	ITP10	$ 464,889	$ 462,150	$ 517,127	$ 431,297
B:615347GRE-MCHENRY4615348GRE-MCHENRY71 FLO BASE CASE	ITP10	$ 408,953	$ 58,673	$ 401,089	$ 55,276
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	ITP10	$ 257,440	$ 271,183	$ 308,760	$ 308,921
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	ITP10	$ 247,828	$ 306,656	$ 243,591	$ 297,564
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	ITP10	$ 194,151	$ 190,495	$ 186,666	$ 139,798
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	ITP10	$ 188,723	$ 412,074	$ 176,865	$ 468,598
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	ITP10	$ 179,921	$ 174,079	$ 183,645	$ 179,477
B:532913KELLY 5 532920TECHILL5 1 FLO KELLY5-KELLY3 115[1](WER	ITP10	$ 157,061	$ 106,386	$ 143,538	$ 74,162
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	ITP10	$ 154,155	$ 49,649	$ 159,492	$ 43,462
B:615348GRE-MCHENRY7659113VOLTAIR7 1 FLO GRE-BALTA4-RUGBY4 230[1]	ITP10	$ 149,860	$ 190,691	$ 156,967	$ 12,344
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	ITP10	$ 138,491	$ 142,520	$ 158,794	$ -
I:FTCAL_S FLO BASE CASE	ITP10	$ 132,450	$ -	$ 133,100	N/A
B:532937NEOSHO 5 547469RIV4525 1 FLO 7BLACKBERRY-NEOSHO 7 345	ITP10	$ 115,799	$ 111,724	$ 119,038	$ 130,326
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	ITP10	$ 99,579	$ 102,201	$ 90,374	$ 86,389
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	ITP10	$ 94,603	$ 24,237	$ 124,743	N/A
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	ITP10	$ 90,904	$ 88,022	$ 88,107	N/A
B:506948SILOAM 5 512643SILMCTY5 1 FLO FLINTCR7-TONECE7 345[1](	ITP10	$ 76,650	$ 74,152	$ 77,933	$ 84,608
B:527036SHELL_C2 3527136DENVER_S 31 FLO LE-WEST_SUB3-LE-LOVINTON	ITP10	$ 75,257	$ 62,267	$ 74,685	N/A
B:549984BROOKLINE 7549969BROOKLINE 51 FLO BROOKLINE7-BROOKLINE5 16	ITP10	$ 74,465	$ 82,630	$ 87,490	$ 97,027
B:652524SIOUXFL7 603012LAWRENC7 1 FLO SPLT RK4-SIOUXFL4 230[1]	ITP10	$ 70,107	$ 85,738	$ 65,302	$ 71,499
B:608740GR RPDS7 618009GRE-POKEGMT71 FLO FORBES 2 500-CHIS-N 2 50	ITP10	$ 62,701	$ -	$ 56,678	N/A
B:640377TEKAMAH5 635201RAUN 5 1 FLO RAUN 3-S34513 345[1](MEC	Side Bar	$ 12,502	$ 201,805	$ 8,592	$ 70,785
B:515802GRACMNT4 520814ANADARK4 1 FLO S.W.S.-4-WASHITA4 138[1]	Side Bar	$ 3,831	$ 69,028	$ 8,941	$ 79,851
B:3340754LONGMIR! 3340874PONDEROSA% 1 FLO 4PONDEROSA%-4CONROE1 138	Side Bar	N/A	N/A	N/A	$ 181,420
B:523945PANTEX_S 3523931HIGHLAND_TP31 FLO HUTCH_S 3-MARTIN	Side Bar	N/A	$ 37,985	N/A	$ 53,849
B:603270MAGIC CITY 7605634VELVA TAP 1 FLO GRE-MCHENRY7-VOLTAIR7 11	Side Bar	N/A	N/A	N/A	$ 62,416
B:615348GRE-MCHENRY7615347GRE-MCHENRY41 FLO GRE-BALTA4-RUGBY4 230[1]	Side Bar	N/A	N/A	N/A	$ 464,643

Future 2 Congestion Scores

F2 Constraints	Constraint Source	Existing ITP10 model		BASE CONG Score with Wind Profile Update	Side Bar BASE CONG Score
		BASE CONG Score without model corrections	BASE CONG Score with model corrections		
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	ITP10	$ 662,310	$ 672,610	$ 710,582	$ 577,366
B:615347GRE-MCHENRY4615348GRE-MCHENRY71 FLO BASE CASE	ITP10	$ 597,138	$ 70,938	$ 601,276	$ 81,598
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	ITP10	$ 536,225	$ -	$ 530,150	$ -
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	ITP10	$ 371,481	$ 459,243	$ 375,649	$ 474,260
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	ITP10	$ 300,035	$ 581,998	$ 312,862	$ 658,231
B:661008BEULAH 7 661018COYOTE 7 1 FLO CENTER 4-MANDAN 4 230[1]	ITP10	$ 293,122	$ -	$ 285,343	$ -
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	ITP10	$ 218,942	$ 224,818	$ 201,737	$ 164,893
B:615348GRE-MCHENRY7659113VOLTAIR7 1 FLO GRE-BALTA4-RUGBY4 230[1]	ITP10	$ 149,813	$ 175,849	$ 148,311	$ 10,066
B:530693VINETAP3 530581N HAYS3 1 FLO KNOLL 6-POSTROCK6 230[1]	ITP10	$ 134,509	$ 130,143	$ 141,473	$ 125,676
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	ITP10	$ 128,073	$ 144,986	$ 143,621	$ 139,836
B:520510NAPLESTP 520867CORN TP4 1 FLO SUNNYSD7-G14-057T 345[1]	ITP10	$ 125,364	$ 8,646	$ 136,481	$ 6,546
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	ITP10	$ 110,046	$ 108,989	$ 127,951	$ -
B:3388135MIDWY JRDN#505460BULL SH5 1 FLO BUFORD5-BULL SH5 161[1](	ITP10	$ 96,338	$ 97,148	$ 119,920	$ 79,817
I:FTCAL_S FLO BASE CASE	ITP10	$ 85,756	$ -	$ 83,096	N/A
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	ITP10	$ 81,181	$ 11,255	$ 75,991	$ 2,953
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	ITP10	$ 79,960	$ 78,768	$ 67,580	N/A
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	ITP10	$ 79,745	$ 64,604	$ 62,402	$ 48,211
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	ITP10	$ 79,392	$ 23,150	$ 129,385	N/A
B:652524SIOUXFL7 603012LAWRENC7 1 FLO SPLT RK4-SIOUXFL4 230[1]	ITP10	$ 79,374	$ 89,314	$ 78,054	$ 79,219
B:515339VBI 5 515347HWY59 5 1 FLO MUSKOGE7-FTSMITH7 345[1]	ITP10	$ 71,172	$ -	$ 68,022	N/A
B:530592SMOKYHL6 532873SUMMIT 6 1 FLO POSTROCK7-AXTELL 3 345[1	ITP10	$ 58,462	$ 63,959	$ 50,959	$ 56,825
B:506948SILOAM 5 512643SILMCTY5 1 FLO FLINTCR7-TONECE7 345[1](	ITP10	$ 50,011	$ 52,467	$ 52,373	$ 64,916
B:635003SUB701 5 646211S1211 5 1 FLO CBLUFFS3-S34563 345[1](M	Side Bar	$ 30,199	$ 66,251	$ 19,614	$ 54,184
B:515802GRACMNT4 520814ANADARK4 1 FLO S.W.S.-4-WASHITA4 138[1]	Side Bar	$ 4,747	$ 69,243	$ 8,752	$ 72,698
B:3340754LONGMIR! 3340874PONDEROSA% 1 FLO 4PONDEROSA%-4CONROE1 138	Side Bar	N/A	N/A	N/A	$ 279,455
B:603270MAGIC CITY 7605634VELVA TAP 1 FLO GRE-MCHENRY7-VOLTAIR7 11	Side Bar	N/A	N/A	N/A	$ 96,234
B:615348GRE-MCHENRY7615347GRE-MCHENRY41 FLO GRE-BALTA4-RUGBY4 230[1]	Side Bar	N/A	N/A	N/A	$ 457,039

Future 3 Congestion Scores

F3 Constraints	Constraint Source	Existing ITP10 model		BASE CONG Score with Wind Profile Update	Side Bar BASE CONG Score
		BASE CONG Score without model corrections	BASE CONG Score with model corrections		
B:652216WATFORD4 652408WATFORD7 1 FLO BASE CASE	ITP10	$ 821,749	$ -	$ 817,813	$ -
B:615650GRE-CHUBLAK7616929GRE-KENRICK71 FLO HELENA 3-SCOTTCO3 345[1]	ITP10	$ 635,398	$ -	$ 612,685	N/A
B:526076STANTON_W 3526146INDIANA 31 FLO TUCO_INT 6-CARLISLE 6 23	ITP10	$ 379,447	$ 364,279	$ 441,490	$ 420,522
B:507755S SHV 4 507765WALLAKE4 1 FLO FTHUMBG4-TRICHEL4138[1](	ITP10	$ 274,213	$ 284,236	$ 283,175	$ 206,395
B:652508S3 7 652551GRANITF7 1 FLO LYON CO 3-LYON CO7 115[9	ITP10	$ 221,315	$ 248,925	$ 219,886	$ 241,405
B:532987BUTLER 4 533001ALTOONA4 1 FLO CANEYRV7-NEOSHO 7 345[1]	ITP10	$ 166,526	$ 176,320	$ 175,719	$ 176,721
B:514785WOODWRD4 515785WINDFRM4 1 FLO WODWRD 269-WOODWRD4 138[	ITP10	$ 109,243	$ 104,541	$ 115,678	$ -
B:532937NEOSHO 5 547469RIV4525 1 FLO 7BLACKBERRY-NEOSHO 7 345	ITP10	$ 103,326	$ 100,552	$ 100,159	$ 96,378
B:524606HEREFORD 3524629DS-#6 31 FLO DF PLX TP6-PLANT_X6 230[	ITP10	$ 94,461	$ 98,666	$ 93,853	$ 105,505
B:526434SUNDOWN 3526435SUNDOWN 61 FLO LAMB_CNTY3-HOCKLEY3 115[	ITP10	$ 92,582	$ 36,233	$ 138,894	N/A
B:520510NAPLESTP 520867CORN TP4 1 FLO SUNNYSD7-G14-057T 345[1]	ITP10	$ 88,668	$ 3,960	$ 83,704	$ 1,037
B:527275SEMINOLE 3527276SEMINOLE 62 FLO SEMINOLE 6 XFR 230/115[1	ITP10	$ 87,371	$ 80,567	$ 84,289	N/A
B:542985NEAST 5 543133CHARLOT5 1 FLO NEAST5-GRAND W5 161[1](K	ITP10	$ 82,395	$ 65,986	$ 70,601	$ 61,757
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-SEMINOL7 345[1]	ITP10	$ 4,702	$ 2,637	$ 7,243	$ 190
B:505600TUPELO 4 521071TUPLOTP4 1 FLO PITTSB-7-VALIANT7 345[1]	ITP10	$ 57,979	N/A	$ 57,644	$ -
I:REDWILLMINGO FLO BASE CASE	ITP10	$ 53,504	$ 44,425	$ 46,508	$ 41,852
B:652515HURON 7 660009BTAP WP7 1 FLO FTTHOMP4-LETCHER4 230[1]	ITP10	$ 52,591	$ -	$ 47,481	N/A
B:640338SCOTBLF7 640397VICTRYH7 1 FLO STEGALL4-STGXFMR4 230[1]	ITP10	$ 52,309	$ 3,355	$ 52,981	$ 3,145
B:602003BLUEETA5 631043WINBAGO5 1 FLO WILMART3-FIELD_N3 345[1]	Side Bar	$ 31,246	$ 127,515	$ 181,693	$ 145,801
B:515802GRACMNT4 520814ANADARK4 1 FLO S.W.S.-4-WASHITA4 138[1]	Side Bar	$ 11,860	$ 87,093	$ 8,752	$ 85,754
B:3340754LONGMIR! 3340874PONDEROSA% 1 FLO 4PONDEROSA%-4CONROE1 138	Side Bar	N/A	N/A	N/A	$ 170,828
B:661020DIXGREENRVR7661021WSTMD1 7 1 FLO BELFELD3-CHAR.CK3 345[1]	Side Bar	N/A	N/A	N/A	$ 50,220

Final Portfolio Projects B/C Comparison

2017 ITP10 Model Update Impacts

Future 1 B/C Ratios

Project Description	ITP10 B/C	Side Bar B/C	Wind Profiles B/C
Butler - Altoona 138 kV Terminal Upgrades	1.6	1.0	16.8*
Neosho - Riverton 161 kV Terminal Upgrades	57.3	16.6	16.8*
Build new 230kV transmission line from Knoll to Post Rock (CKT 2)	16.2	9.3	9.6
South Shreveport - Wallace Lake 161 kV Ckt 1 Rebuild	2.5	2.2	2.2
Morgan 345/161kV Transformer	2.8	2.2	2.8
Tupelo - Tupelo Tap 138 kV Terminal Upgrades & Lula - Tupelo Tap 138 kV Terminal Upgrades #1	144.0	73.8	2.3
Kelly - Tecumseh Hill 161 kV Terminal Upgrades	12.4	0.8	1.3
Tuco - Stanton - Indiana - SP-Erskine 115 kV Terminal Upgrades	61.7	65.6	70.7
Siloam Springs - Siloam Springs City 161 kV Ckt 1 Rebuild	2.8	5.7	1.8
Lawrence - Sioux Falls 115 kV Rebuild	30.6	21.0	14.2
Guinotte 161kV Line Reactor on Northeast-Crosstown Line	31.5	7.3	6.1
Logan-Magic City-Mallard 115kV transmission line	10.1	Baked in	7.2
Upgrade Seminole Transformers	1.7	NTC	1.3
Ink Basin Project	2.4	NTC	2.1
Tolk-Yoakum Tap at Lehman-Cochran Tap	1.9	NTC	1.8
Woodward PST	7.3	NTC	6.8

*Paired Projects

Future 3 B/C Ratios

Project Description	ITP10 B/C	Side Bar B/C	Wind Profiles B/C
Butler - Altoona 138 kV Terminal Upgrades	37.0	41.9	57.0*
Neosho - Riverton 161 kV Terminal Upgrades	140.8	156.2	57.0*
South Shreveport - Wallace Lake 161 kV Ckt 1 Rebuild	3.5	3.1	3.1
Tuco - Stanton - Indiana - SP-Erskine 115 kV Terminal Upgrades	63.4	65.6	66.4
Hereford - DS#6 - Friona 115 kV Rebuild	1.1	2.5	1.6
Guinotte 161kV Line Reactor on Northeast-Crosstown Line	28.6	22.5	20.3
Woodward PST	7.8	NTC	8.0
Upgrade Seminole Transformers	1.2	NTC	1.0
Tolk-Yoakum Tap at Lehman-Cochran Tap	2.1	NTC	2.8

*Paired Projects


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

2017 ITP10 Project Recommendations

December 8th, 2016

ESWG/TWG

SPP Staff

Terms and Notes

- **Base B/C**: benefit to cost ratio of the project in the approved base model
- **Sidebar B/C**: benefit to cost ratio of the project in the updated base model
- **Rec.**: Yes/No to recommend the project for final approval with NTC issuance to be decided by staging date and lead times
- **Annual operational congestion**: the average congestion cost seen on the economic need or appropriate proxy
- All costs are study estimates in 2017$ unless otherwise noted
- B/C ratios are representative of one-year benefit to cost unless otherwise noted
- Project performance data is in the context of the portfolio for which it was selected. Additional information regarding performance in other models may be listed in bullets

Projects with Existing NTCs

General Description	Future	Rec.	Staging
Install 138kV phase shifting transformer at Woodward EHV	F1/F3	GI	No Change
Upgrade Seminole 230/115kV Transformers	F1/F3	ITPNT	No Change
Tolk-Yoakum 230kV Tap at Lehman-Cochran 115kV Tap	F1/F3	ITPNT	No Change
Yoakum-Hobbs 230kV Tap at Allred Tap-Waits 115kV Tap	F1/F3	ITPNT	No Change

- These projects have been confirmed as beneficial in the 2017 ITP10
- SPP recommends no change to scope of projects or staging dates

Reliability

2017 ITP10 Project Recommendations

Atwood 115 kV and Seguin Tap 115 kV Cap Banks

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Cap Banks at Atwood 115kV and Seguin Tap 115kV	Reliability	$1M	F1	N/A	N/A	No	N/A

- Need in F1 summer only at Colby 115 kV, but F2/F3 values above threshold
- ~33 MW load at Colby served radially after contingency
- Side Bar values not below threshold in any future
- Additional considerations
  - 115 kV bus at Colby cost prohibitive for upgrades
  - 69 kV bus at Colby better location for solution

Knox Lee – South Texas Eastman 138kV Rebuild

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Knox Lee to South Texas Eastman 138kV rebuild	Reliability	$8.5	F1	N/A	N/A	No	N/A

- Side-bar impact:
  - Did not meet constraint assessment criteria but added as a constraint to determine impact
  - Minimal congestion (<$5K)
- Recommend invalidation of reliability need

Grapevine/Nichols – Martin 115kV

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
New sub on the Nichols to Grapevine 230kV line and new line from new sub to Martin	Reliability	$15.0	F1	N/A	N/A	No	N/A

- Side-bar impact:
  - $54K/$49K/$33K congestion scores in F1/F2/F3, respectively
- Annual operational congestion: $0.7M
  - Contingent: Martin – Hutchison 115kV
- Recommend reclassification of need from reliability to economic and select alternate project

Grapevine/Nichols – Martin 115kV Continued…

General Description	Type	Cost Estimate ($M)	F1 Sidebar B/C	F3 Sidebar B/C	Rec.	Staging
Replace terminal equipment on Martin to Pantex North and Pantex South to Highland Tap	Economic	$0.7*	14.2	0.3	Yes	TBD

- Other considerations
  - Current operational remedial action scheme (RAS) being discussed
  - Historical issues in area
    - Previous NTC project withdrawn
- Recommendation
  - Replace selected project with terminal upgrades on Martin – Pantex North and Pantex South – Highland Tap 115kV

*Conceptual Cost

Economic

2017 ITP10 Project Recommendations

Logan/Mallard – Magic City 115kV

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Double circuit 115kV line from Magic City to a point on the Logan - Mallard 115kV line.	Economic	$3.1	F1	18.9	9.7	No	N/A

- Sidebar impact: congestion decreased ~85% (McHenry XFR)
  - Model includes full Magic City project approved jointly between Basin and XEL (MISO)
  - Other constraints in the area remain congested as well
- Annual operational congestion: $1.9M
  - Monitored: McHenry 230/115kV Transformer
- Other considerations
  - F3 Sidebar B/C of -0.6
  - Issue largely driven by MISO proxy wind (650MW sited on north end of constraint)

Lawrence – Sioux Falls 115kV Rebuild

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Lawrence - Sioux Falls 115kV rebuild	Economic	$1.4	F1	34.0	30.1	No	N/A

- Side-bar impact: congestion roughly equivalent
- Annual operational congestion: no data
  - Congestion resolved by system reconfiguration
  - Op Guide to operate line open
    - No additional issues caused
- Other considerations
  - F3 base screening B/C of -0.9
  - Non-SPP facility
  - Need in SPP-MISO CSP

Northeast – Charlotte 161kV Reactor

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Series reactor on Northeast - Charlotte 161kV line	Economic	$0.5	F1/ F3	28.0/ 28.6	15.0/ 22.5	Yes	2018

- 2ohm selected in F1, 1ohm selected in F3
- Side-bar impact: congestion decreased ~13-25%
- Annual operational congestion: $83K
  - Monitored: Northeast – Charlotte 161kV
- Recommend 2 ohm (F1) over 1 ohm (F3)
  - Both sizes perform similarly
  - 1 ohm appears to have better B/C but leaves unresolved congestion
  - Northeast – Charlotte 161 kV is an underground line
- Other considerations
  - Load driving congestion goes in service 2018
  - 2018 need in the 2017 ITPNT

Kelly – Tecumseh 161kV Terminal Upgrades

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Kelly and/or Tecumseh 161kV terminal upgrades	Economic	$1.6	F1	12.4	0.8	No	N/A

- Side-bar impact: congestion reduced ~50%
- Annual operational congestion: ~$400K
  - Monitored: Kelly – Tecumseh Hill 161kV
  - Congestion reduced by system reconfiguration
- Other considerations
  - Changes in congestion in sidebar driven Fort Calhoun retirement
  - Project would aid in current Operations reconfigurations, but would not eliminate the need for reconfiguration
  - Nebraska City to Sibley 345kV transmission line project will aid in mitigating current Operations issues

Post Rock – Knoll 230kV

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Second 230kV line from Knoll to Post Rock	Economic	$3.4	F1	16.2	9.3	Yes	2017

- Side-bar impact: congestion roughly equivalent
- Annual operational congestion: $4.7M
  - Contingent: Post Rock - Knoll 230kV
  - Operational concerns: does not protect against Knoll 230/115 kV outage
    - Flowgate modeled but not congested in PROMOD simulations
- Other considerations
  - F3 base screening B/C of 10.2
  - Add 2nd Knoll 230/115 kV to selected project (+~$7M)

Butler – Altoona 138kV Terminal Upgrades

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Upgrade any necessary terminal equipment at Butler and/or Altoona to increase the rating of the 138kV line	Economic	$0.2	F1/ F3	1.6/ 37.0	1.0/ 41.9	Yes	2017

- Side-bar impact: congestion roughly equivalent
- Annual operational congestion: $1.5K
  - Monitored: Butler – Altoona 138kV
  - Congestion reduced by system reconfiguration
- Other considerations
  - Project works well in conjunction with alleviation of Neosho – Riverton 161 kV constraint.
  - Upstream constraints begin to bind when flowgate is alleviated

Neosho – Riverton 161kV Terminal Upgrades

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Upgrade any necessary terminal equipment at Neosho and/or Riverton to increase the rating of the 161kV line	Economic	$0.1	F1/ F3	57.3/ 140.8	16.6/ 156.2	Yes	2017

- Side-bar impact: ~+/- 10% congestion change in F1 and F3, respectively
- Annual operational congestion: $5.3M
  - Monitored: Neosho – Riverton 161kV

Siloam – Siloam City 161kV Rebuild

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Siloam Springs (AEP)-Siloam Springs City (GRDA) 161kV rebuild	Economic	$5.2	F1	4.9	4.9	Yes	2017

- Side-bar impact: congestion increased ~10%
- Annual operational congestion: $5.2M
  - Monitored: Siloam Springs – Siloam Springs City 161kV
- Other considerations
  - F3 Sidebar B/C of 1.75

Tupelo – Tupelo Tap – Lula 138kV Terminal Upgrades

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Tupelo, Tupelo Tap and Lula 138 kV terminal upgrades	Economic	$0.1	F1	144.0	73.8	Yes	2020

- Side-bar impact: congestion reduced ~70%
- Annual operational congestion: $0
  - Monitored: Tupelo – Tupelo Tap – Lula 138kV
- F3 Screening B/C = 10.2

South Shreveport – Wallace Lake 138kV Rebuild and Port Robson Cap Bank

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Rebuild South Shreveport to Wallace Lake 138kV	Economic	$17.0	F1/ F3	2.5/ 3.5	2.2/ 3.1	No	N/A
Install capacitor bank at Port Robson 138 kV	Reliability	$2.3M	F1/ F3	N/A	N/A	No	N/A

- Side-bar impact: congestion reduced ~25%
- Annual operational congestion: No data
- Other considerations
  - Driven by industrial load
    - Projections have changed per AEP
    - Load not modeled in 2017 ITPNT
- Recommendation to not issue NTC via 2017 ITP10
  - SPP has uncertainty due to changing expectations and inconsistent modeling
  - Load increase should go through Attachment AQ study process
  - Original project for Port Robson is a 28.8MVAR cap bank; size of this cap bank would need to double with expected load increase

Tuco – Stanton – Indiana – Erskine 115kV Terminal Upgrades

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Upgrade any necessary terminal equipment at Tuco and/or Stanton and/or Indiana and/or SP-Erskine to increase the rating of the 115kV line	Economic	$1.0	F1/ F3	61.7/ 63.4	65.6/ 65.6	Yes*	2017

- Side-bar impact: ~+/- 10% congestion change in F1 and F3, respectively
- Annual operational congestion: $6.2M
  - Monitored: Stanton – Indiana 115kV
- Recommend approval of terminal equipment upgrade at Tuco and/or Stanton 115kV
  - *Other terminal upgrades already completed by SPS

Target Areas

2017 ITP10 Project Recommendations

Morgan 345/161kV Transformer

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
345/161kV transformer at Morgan substation	Economic	$8.7	F1	2.8	2.2	No	N/A

- Side-bar impact: congestion increased ~30%
- Annual operational congestion: $4.7M
  - Monitored/Contingent: Brookline 345/161kV Transformer(s)
- Investigate alternative solution

Hereford – DS#6 115kV Rebuild

General Description	Type	Cost Estimate ($M)	Future	Base B/C	Sidebar B/C	Rec.	Staging
Hereford to DS#6 115kV rebuild	Economic	$3.6	F3	1.1	2.5	No	N/A

- Side-bar impact: congestion increased ~10%
- Annual operational congestion: $21M
  - Monitored: Osage – Canyon 115kV
- Investigate comprehensive solution

2017 ITP10 Alternative Project Analysis

December 8th, 2016

ESWG/TWG

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Alternative Project Analysis

- Certain transmission issues identified under scope and out of scope criteria were posted for informational purposes
- This was done to allow for submittal and further evaluation of projects that may support SPP initiatives
  - RCAR II
  - Seams
  - Operational issues
- Two target areas for alternative project recommendations
  - Eastern Seams
    - Southeast Kansas – Southwest Missouri
    - Northeast Oklahoma – Northwest Arkansas
  - Texas Panhandle
    - SPS North to South

Eastern Seams

Eastern Seams - Background

- Loading in NW Arkansas and SW Missouri, high exports, limited hydro and Springfield generation can lead to these constraints becoming congested
- Southeast Kansas – Southwest Missouri needs
  - Neosho - Riverton 161kV FLO
    Neosho – Blackberry 345kV - F1, F3
  - Brookline 345/161kV Xfmr #1 FLO Brookline 345/161kV Xfmr #2 – F1, F3
  - Butler - Altoona 138kV FLO
    Neosho – Caney River 345kV F1, F2, F3
- Northeast Oklahoma-Northwest Arkansas needs
  - Siloam City-Siloam Springs161kV FLO Flint Creek-Tonnece 7 345kV - F1, F2
  - Bull Shoals - Midway Jordan161kV FLO Bull Shoals - Buford161kV - F2
  - Highway 59 – VBI North161kV FLO
    Fort Smith – Muskogee 345kV - F2 - Model Correction

Brookline Transformer – Background

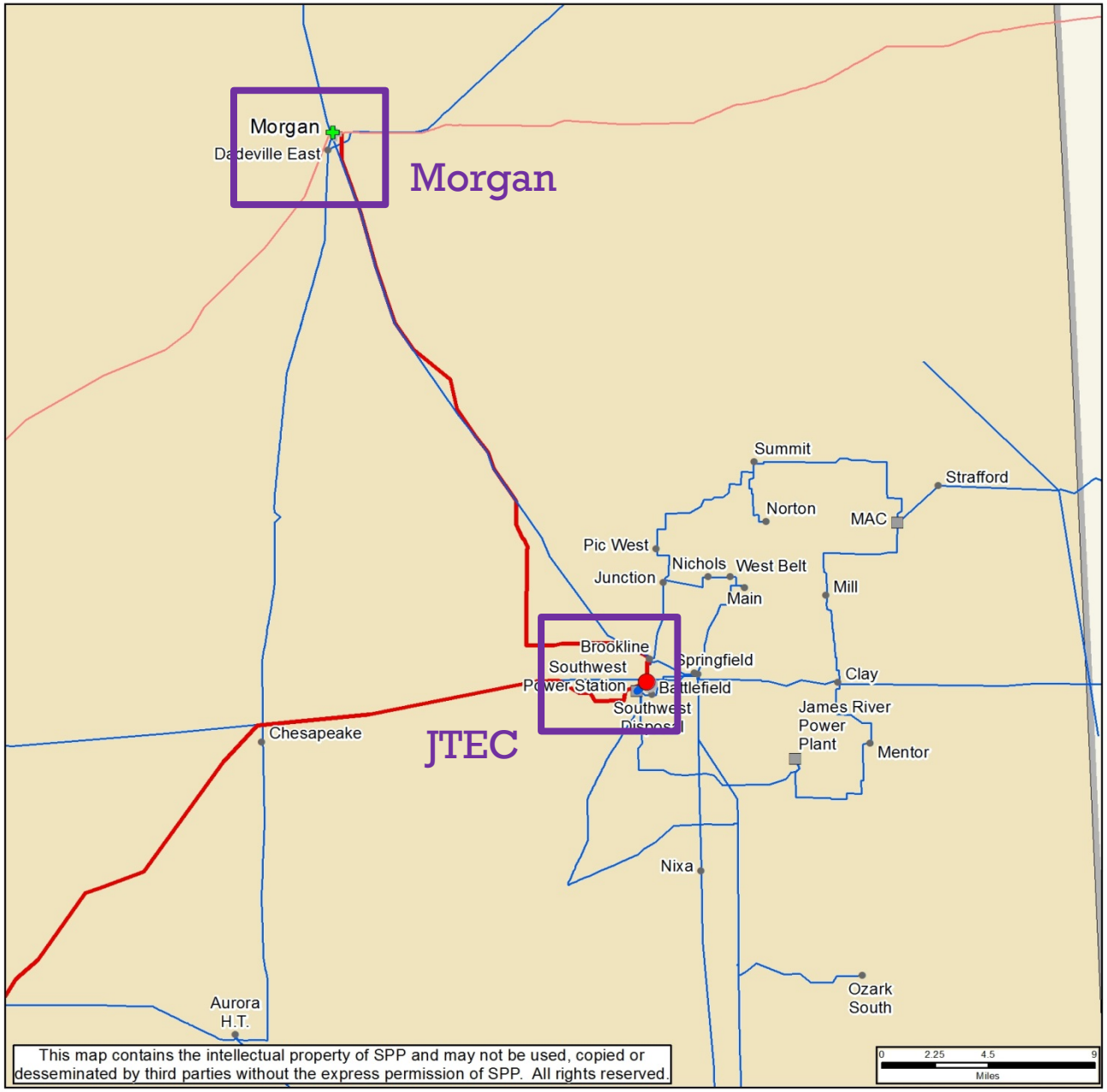
- Brookline 345/161kV Xfmr #1 FLO Brookline 345/161kV Xfmr #2 identified as an Economic Need in Future 1 and a Reliability Need related to an Economic Constraint in Future 3
  - F1/F2 portfolio project to add a Morgan 345/161 kV transformer has poor performance in Future 3
  - The project selected by the ITP10 process:
    - Might not be the best long-term solution for the Springfield area
    - Might not address certain operational issues in CUS as well as alternative projects
    - Is not a flexible solution across differing futures
- Additional analysis warranted to assess other factors not evaluated in the standard ITP10 process

Alternative project analysis for Brookline Transformer

- Additional economic project testing with additional constraints
- Economic Sensitivities of top alternatives
  - Hydro Generation Dispatch Sensitivity Impact
- Reliability Sensitivities of top alternatives
  - Reliability Metrics
  - AC contingency analysis runs and comparisons including 69 kV (<100% thermal and >0.90 voltage monitoring)

Top Brookline Project Alternatives

- Two projects have been identified as viable alternatives to the Morgan 345/161 kV transformer project
  - Add Morgan 345/161 kV transformer, and uprate the Brookline to Morgan 161 kV transmission line to achieve an emergency summer rating of 208MVA, and an emergency winter rating of 232 MVA.
  - Tap the 345 kV transmission line from Flint Creek to Brookline, and add a new substation with a 345/161 kV transformer. Add a 0.5 mile 161 kV connection from the new sub to JTEC.
- These two project alternatives have positive benefits in screening as well as sensitivity runs across different futures, and have higher B/C ratios than other projects evaluated

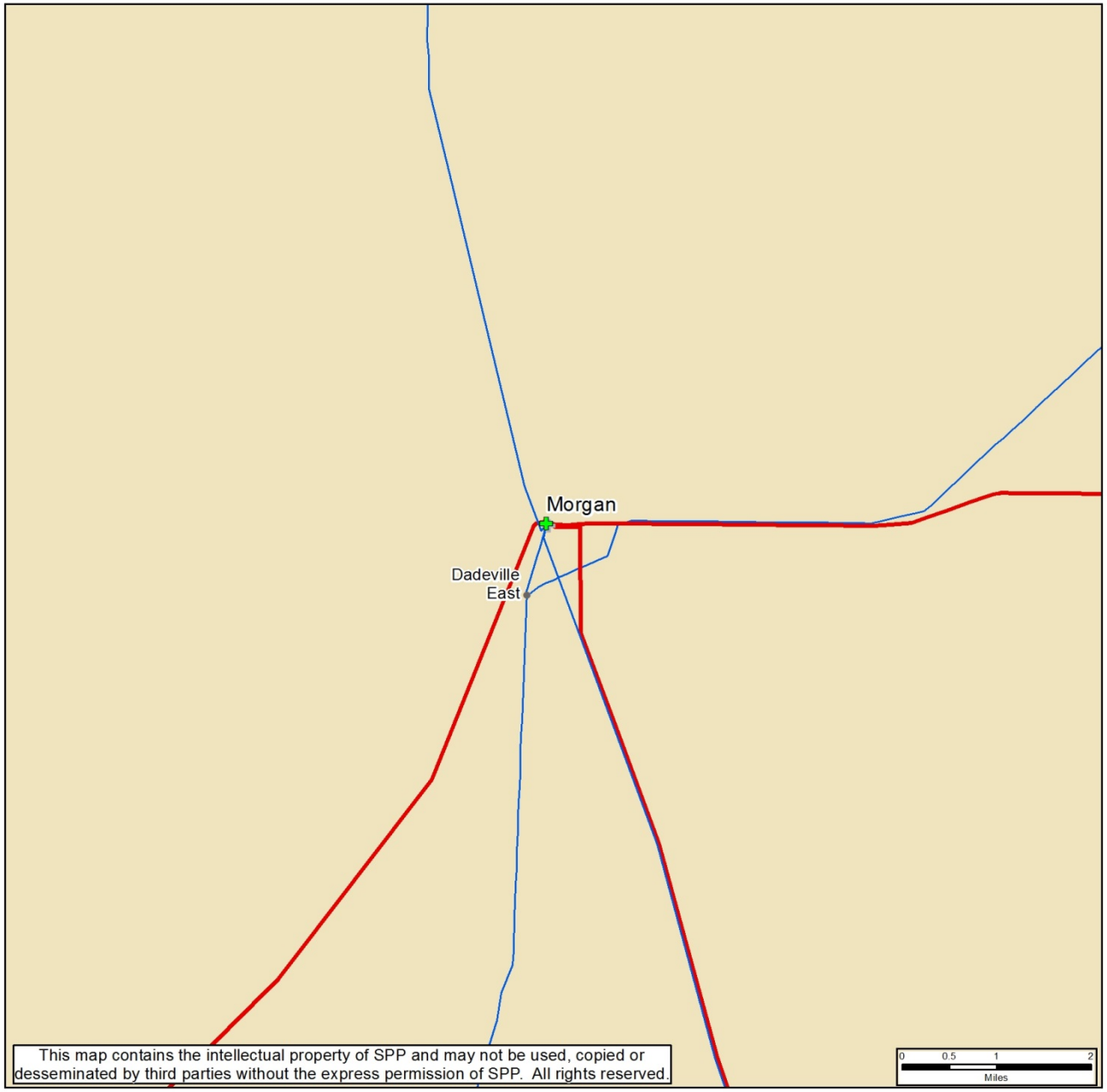


SPP 75th Anniversary

Springfield Alternate Projects

- Cap Bank
- New Sub
- Condenser
- Terminal Equipment
- Transformer
- New Line
- Line Upgrade
- New Line
- Line Upgrade

- 115 kV
- 161 kV
- 230 kV
- 345 kV
- 500 kV

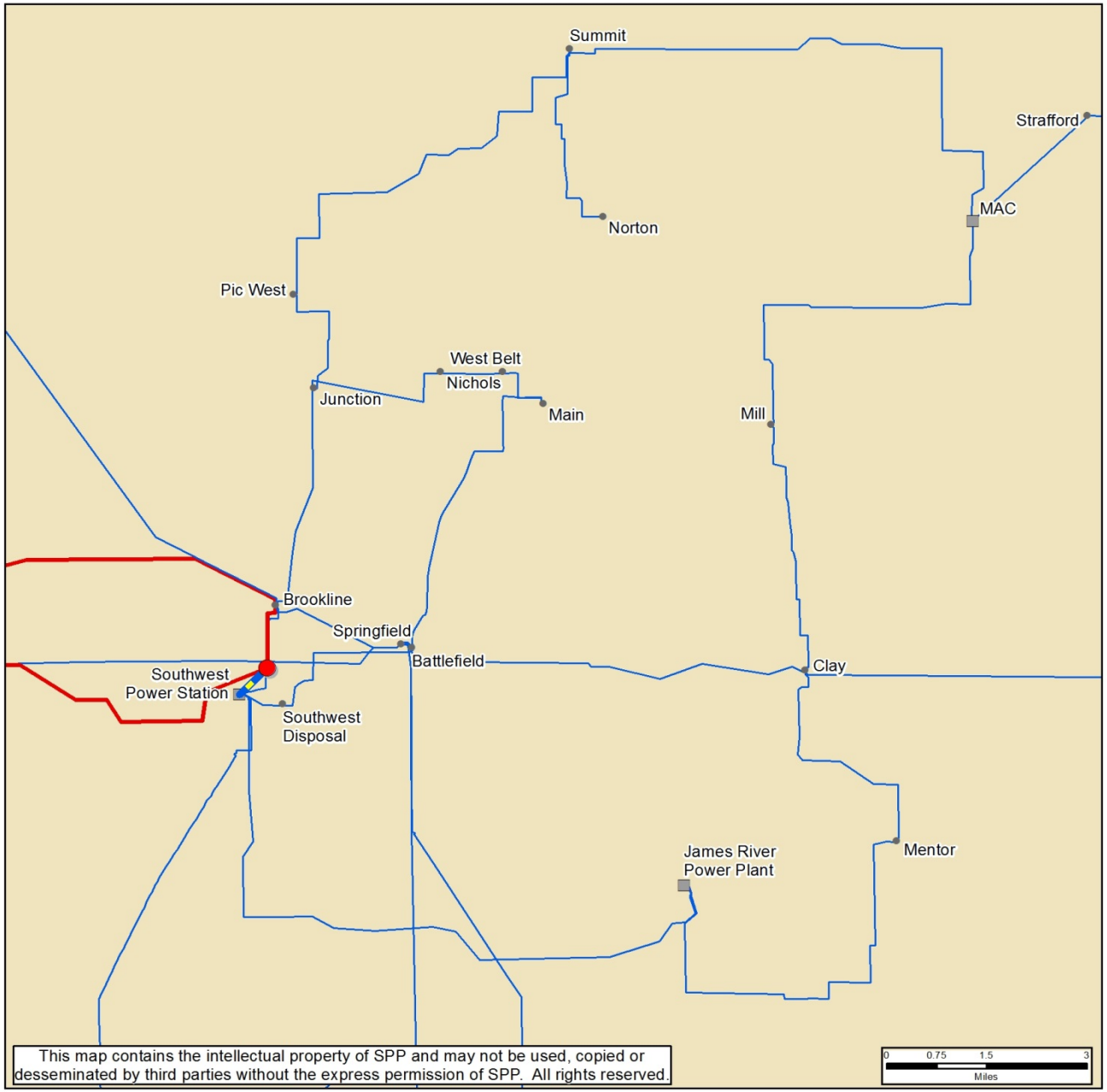


Springfield Alternate Projects

Morgan

- Cap Bank
- New Sub
- Condenser
- Terminal Equipment
- Transformer
- New Line
- Line Upgrade
- New Line
- Line Upgrade

- 115 kV
- 161 kV
- 230 kV
- 345 kV
- 500 kV



SPP 75th Anniversary 75

Springfield Alternate Projects

JTEC

- Cap Bank
- New Sub
- Condenser
- Terminal Equipment
- Transformer
- New Line
- Line Upgrade
- New Line
- Line Upgrade

- 115 kV
- 161 kV
- 230 kV
- 345 kV
- 500 kV

N

Brookline Economic Evaluation and Sensitivity Results

Project	Future	1-year Project Cost	Screening		Hydro Operation Sensitivity		Hydro Reduction Sensitivity	
			SPP Benefit	SPP 1-yr B/C	SPP Benefit	SPP 1-yr B/C	SPP Benefit	SPP 1-yr B/C
Morgan Xfmr + line upgrade	F1	$1.6M	$1.8M	1.1	$4.4M	2.7	$4.5M	2.8
Morgan Xfmr + line upgrade	F3	$1.6M	$1.0M	0.6	$2.1M	1.3	$2.3M	1.4
Flint Creek - Brookline Tap & Sub, and t-line to JTEC	F1	$4.2M	$3.0M	0.7	$4.4M	1.0	$3.4M	0.8
Flint Creek - Brookline Tap & Sub, and t-line to JTEC	F3	$4.2M	$1.3M	0.3	$2.4M	0.6	$1.6M	0.4

- All Runs are based on the approved 2017 ITP10 model and also include additional constraints
- Screening Runs do not include model corrections, or the respective future portfolio
- Sensitivity Runs include model corrections, the respective future portfolio (minus the Morgan transformer in Future 1), and SWPA hydro generation modifications
- Hydro Operation Sensitivity: Changed SWPA hydro transactions from load following to peaking
- Hydro Reduction Sensitivity: Hydro Operation Sensitivity + 25% reduction in SWPA hydro energy
- Note all B/C numbers in the table are for 1 year. **In addition, 40-year B/C analysis was conducted for the JTEC project, and the project has a 40-year B/C greater than 1.0 in F1 and F3.**
- These calculations assume that SPP picks up 100% of these costs, even though some cost sharing with AECI would be expected for the Morgan project.

Brookline Reliability Sensitivities

- FCITC sensitivity for CUS load growth
  - With each new project, how much CUS load growth (beyond the 2025 total) would it take to overload the Brookline transformer at summer peak?
- Morgan 345/161 kV xfmr + 161 kV line upgrade
  - F1: Takes 15% load increase to overload Brookline
  - F3: Takes 24% load increase to overload Brookline
- Flint Creek – Brookline tap & sub, and new 161 kV line to JTEC
  - F1: Takes > 38% load increase to overload Brookline
  - F3: Takes > 38% load increase to overload Brookline
- Both projects provide adequate transfer capability into Springfield in the event of future load growth beyond the 2025 projections

Brookline Reliability Sensitivities

	Springfield – Clay (Con: James River – Southwest 161 kV)		Brookline – Junction (Con: Battlefield – Main 161 kV)		Brookline Transformer Ckt 1 (Con: Brookline 345/161 kV Transformer Ckt 2)	
	Morgan	JTEC	Morgan	JTEC	Morgan	JTEC
F1 Peak	< 80%	< 80%	96.4%	96.4%	108.4%	108.4%
			94.3%	96.7%	87%	65.2%
F2 Peak	100.3%	100.3%	101.3%	101.3%	98.5%	98.5%
	102.2%	103.5%	99.3%	101.7%	66.3%	57.3%
F3 Peak	97.6%	97.6%	105.2%	105.2%	103.7%	103.7%
	99.6%	100.7%	102.9%	105.7%	65.8%	58.6%

- The three elements shown here are of interest because they are overloaded in the AC model in at least one future, even though they are defined constraints in the DC economic model and do not overload in the DC model.
- Table shows facility loading before and after the project is added. Green indicates the project relieves loading, and red indicates the project aggravates the loading.
- **The JTEC project provides more relief on the Brookline transformer; the Morgan project provides more relief on the Springfield – Clay 161 kV and Brookline – Junction 161 kV facilities.**

Brookline Conclusions

- Two project alternatives were evaluated in lieu of the Morgan 345/161 kV project selected by the standard process
  - Morgan project: Morgan 345/161 kV xfmr + 161 kV line upgrade
  - JTEC project: Flint Creek – Brookline tap & sub, and new 161 kV line to JTEC
- Both projects appear to be cost-justifiable over 40 years in F1 and F3
- Morgan project
  - Shows better B/C ratios
  - Provides additional firm contract path for CUS
  - Provides more relief on the Springfield – Clay 161 kV and Brookline – Junction 161 kV facilities in Springfield
  - Has potential for cost sharing with our neighbor as a seams project, as AECI has shown interest
- JTEC project
  - Is in the CUS zone
  - Provides additional firm contract path for CUS exceeding that of Morgan project
  - Provides better transfer capability into the city of Springfield in the event of increased load growth
  - Provides more relief on the Brookline transformer
  - Could provide more flexibility for additional upgrades if they become needed in the future

Brookline Recommendation

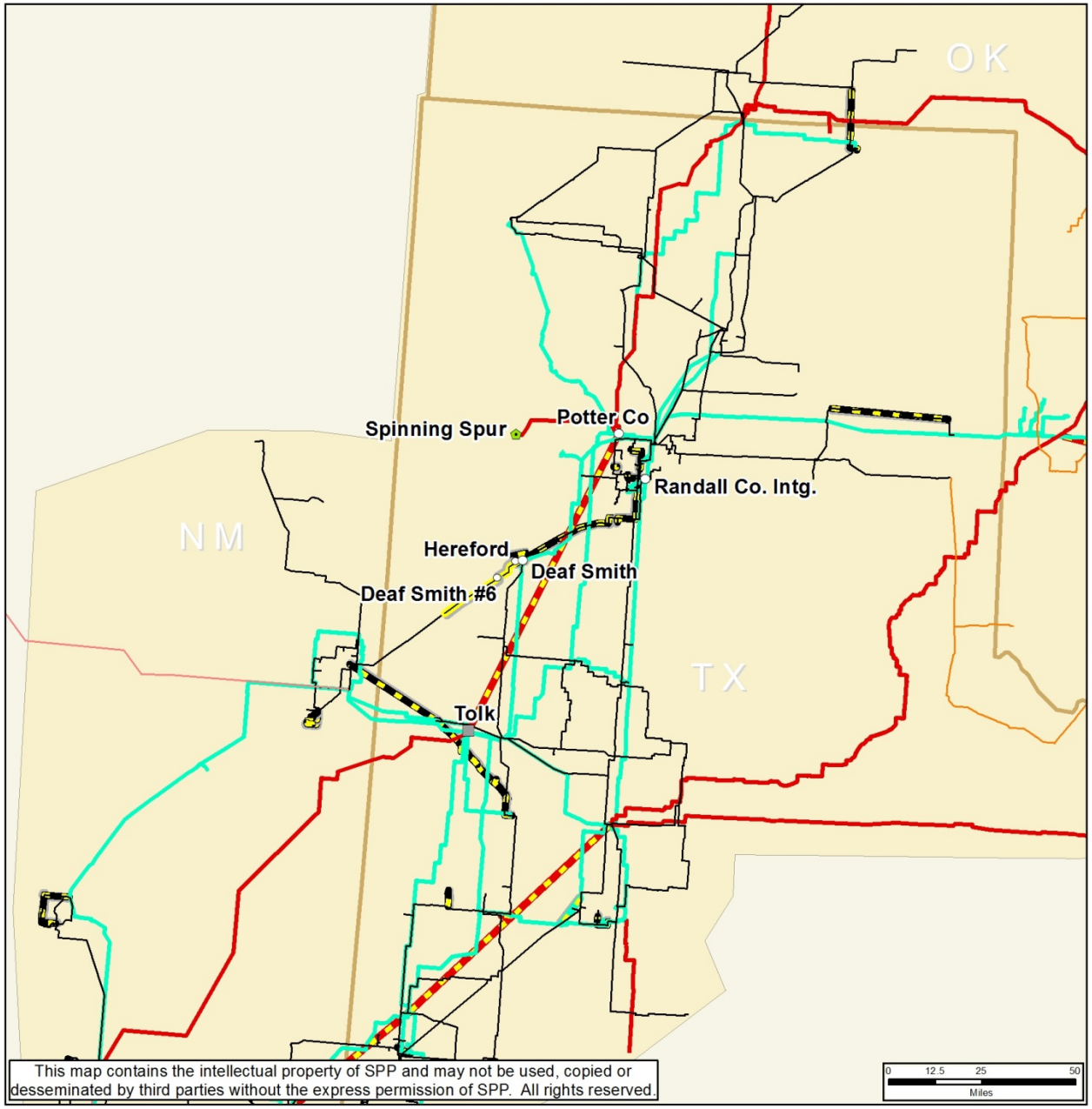
- SPP Staff recommends the Morgan 345/161 kV transformer and the uprate of the Morgan to Brookline 161 kV line as the project solution for the Brookline 345/161 kV transformer need identified in the ITP10.
  - This recommendation is contingent upon SPP and AECI reaching agreement on cost sharing of the transformer and line uprate.

- If agreement cannot be reached between SPP and AECI on cost sharing, SPP Staff would recommend the alternative solution of tapping the Brookline to Flint Creek 345 kV line, installing a new sub with a 345/161 kV transformer, and building a 161 kV line from the new sub to the JTEC substation.

Texas Panhandle

Texas Panhandle - Background

- Top flowgate in state of the market reports
- "The Texas Panhandle corridor relies mainly on 230 kV transmission lines between Amarillo and Lubbock, TX. The transmission corridor is impacted by the predominantly gas-fired generation in the south that is more expensive than wind generation to the north."
- NTCs in progress
- Future 3 - Hereford-DS #6 115kV FLO Deaf Smith PLX Tap – Plant X6 230kV
- SPS North to South Stability Interface



SPP 75th Anniversary 75

2017 ITP10 Economic Solutions

- 115 kV
- 138 kV
- 161 kV
- 230 kV
- 345 kV
- 500 kV
- New Sub
- SVC
- Terminal Equipment
- Transformer
- Alternate New Line
- Prospective Line Upgrade

Texas Panhandle - Uncertainties

- ITP Resource plans and siting to date have reduced the congestion on the constraints for ITP10
- 2017 ITP10 Resource Plan
  - 550 MW of steam gas retirements in South SPS – 220 MW in North SPS
  - F1,F2, and F3 – 4 550 MW CCs in South SPS
  - F3 - 2 additional 216 MW CT
  - F3 includes Solar and Wind South of interface
  - F1 and F2 includes additional Solar and Wind South of interface
- New Mexico Coops and Lea County are transitioning to Western Farmers as the LRE
  - 1-550 MW CC sited in South SPS
- Potential Clean Line integration
- Generation fleet modifications in area
- What best facilitates generation interconnection and transmission service processes as well as maintaining reliability and promoting transmission investment with regional economic benefits?
- Potter to Tolk 345 kV (conceptual cost of $147 million) included in 2010 ITP20 and 2013 ITP20

Texas Panhandle - Analysis

- Potter to Tolk 345 kV alternative
- Economic analysis to include potential future reliability upgrades that could be avoided
- Reliability Sensitivities
  - FCITC Sensitivities to identify potential future reliability needs/projects that could be avoided with economic project alternative
  - Final Reliability Assessment
- Economic Sensitivities
  - #1 - Move 1 CC at Deaf Smith to a 2035 RCAR II site in SPS North
  - #2 - Move 1 CC at Deaf Smith and retire Tolk 1 with CC replacement
  - #3 - Move 1 CC at Deaf Smith and convert 1 CC to 3 CTs at Hobbs
  - Each requires changes to generator outlet facilities, NTC removal, and event file

Texas Panhandle Reliability Sensitivity Results

- FCITC sensitivity for SPS South Imports from SPP
  - What is the cost of incremental least cost upgrades to address thermal overloads that could be addressed by Potter to Tolk 345kV for increased import levels?
    - Using a modified powerflow that includes the same Move 1 CC at Deaf Smith to a 2035 RCAR II site in SPS North
- Before Potter-Tolk 345 kV
  - F3 25 Light Load:
    - 1.5 GW of 2.5 GW Transfer Tested (Sum of Pgen 1.7 GW)
  - F3 25 Summer Peak:
    - 2.2 GW of 6.5 GW Transfer Tested (Sum of Pgen 5.8 GW)
  - High end conceptual cost for incremental upgrades $195M
  - Low end conceptual cost for incremental upgrades $88M
- After Potter-Tolk 345 kV without additional Network Upgrades
  - F3 25 Light Load: At least 1.5 GW
  - F3 25 Summer Peak: At least 2.2 GW
- Incremental upgrades represent the potential avoided reliability upgrades

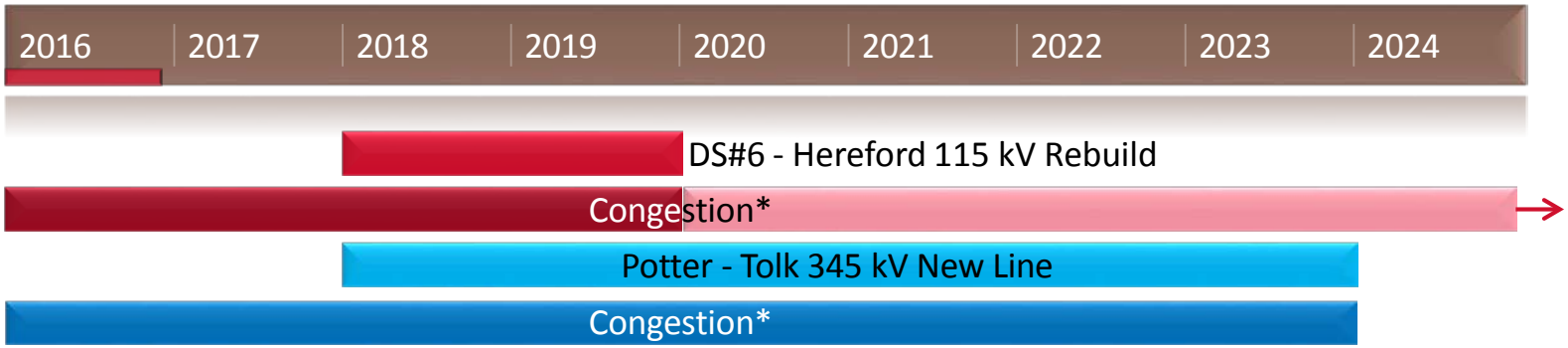
Texas Panhandle Results

- Congestion cost associated with delaying solution in area
- Operations reported $42.2M in congestion cost over the last 2 years for this corridor
- Estimate future congestion cost with PROMOD congestion cost

Texas Panhandle Congestion Cost

- Analysis
  - Future 3 2020 with Reference Case Portfolio
  - Deafsmith CC Move
- Results
  - Rebuilds minimally reduce congestion
  - Comprehensive solution options:
    - Build Potter – Tolk 345 kV
    - Extend 115 kV rebuilds and other incremental upgrades through future studies

Timeline of Potential Projects



Congestion Details:

Option 1 – Rebuild DS#6 – Hereford 115 kV (2017 ITP10 project)

Option 2 – Build Potter – Tolk 345 kV line

Timeline does not include continued congestion cost after project(s) in-service

* Represents an estimated $19.1M per year congestion cost leveraging Future 3 2020 model with economic sensitivity #1 - Move 1 CC at Deaf Smith to a 2035 RCAR II site in SPS North

Economic Sensitivities Results

- Potter-Tolk 345kV *Potential avoided reliability upgrades
  - Base (No sensitivity)

Future	SPP APC Benefit	SPP B/C	Avoided Reliability for 1.0 B/C
F1	$9.5M	0.4	$91.9M
F3	$14.6M	0.6	$62.1M

  - Move 1 CC at Deaf Smith to Moore County a 2035 RCAR II site in SPS North

Future	SPP APC Benefit	SPP B/C	Avoided Reliability for 1.0 B/C
F1	$12.7M	0.5	$73.4M
F3	$13.6M	0.5	$68.1M

  - Move 1 CC at Deaf Smith and retire Tolk 1 with CC replacement

Future	SPP APC Benefit	SPP B/C	Avoided Reliability for 1.0 B/C
F1	$7.0M	0.3	$106.6M
F3	$21.6M	0.9	$20.6M

  - Move 1 CC at Deaf Smith and convert 1 CC at Hobbs to 3 CTs

Future	SPP APC Benefit	SPP B/C	Avoided Reliability for 1.0 B/C
F1	$12.6M	0.5	$73.9M
F3	$14.3M	0.6	$63.9M

All results in the tables include the respective portfolio
SPP conceptual cost = $147M

Economic Sensitivities Results with Conceptual* Cost Variations

- Potter-Tolk 345 *Potential future NTC Deferrals
  - Base (No sensitivity)

Future	Low Cost	Avoided Reliability for 1.0 B/C	High Cost	Avoided Reliability for 1.0 B/C
F1	0.5	$61.5M	0.3	$139.1M
F3	0.7	$31.7M	0.4	$109.3M

  - Move 1 CC at Deaf Smith to Moore County a 2035 RCAR II site in SPS North

Future	Low Cost	Avoided Reliability for 1.0 B/C	High Cost	Avoided Reliability for 1.0 B/C
F1	0.6	$43.0M	0.4	$120.6M
F3	0.7	$37.7M	0.4	$115.3M

  - Move 1 CC at Deaf Smith and retire Tolk 1 with CC replacement

Future	Low Cost	Avoided Reliability for 1.0 B/C	High Cost	Avoided Reliability for 1.0 B/C
F1	0.4	$76.3M	0.2	$153.8M
F3	1.1	N/A	0.7	$67.8M

  - Move 1 CC at Deaf Smith and convert 1 CC at Hobbs to 3 CTs

Future	Low Cost	Avoided Reliability for 1.0 B/C	High Cost	Avoided Reliability for 1.0 B/C
F1	0.6	$43.6M	0.4	$121.2M
F3	0.7	$33.6M	0.4	$111.2M

All results in the red tables include the respective portfolio
*Tuco – Yoakum 345 kV and Yoakum – Hobbs 345 kV used for per mile cost

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

December 8th, 2016

	Action Item	Date Originated	Status	Comments
057	SPP staff will write a straw-man procedure or portion of the ITP manual that deals with conventional and wind generation planning and siting within the ITP process. The process should be in place by the Spring of 2015.	August 23rd, 2012	In Progress Staff	A draft resource siting whitepaper will be developed for review mid-2016.
151	Staff to look into optional software tools for use in ITP studies.	May 20th, 2015	In Progress Staff	Staff is meeting with software vendors and users and expects to have a recommendation on any potential resource planning software changes by 4th quarter 2016.
160	SPP Staff and the ESWG are to formalize standard procedures for data requests and member review of information related to ITP studies.	January 21st, 2016	In Progress Staff/ESWG	Combined item representative of AI148 and AI149.
161	Staff to report on carbon emissions as the 2017 ITP10 study moves forward through the different milestones.	February 24th-25th, 2016	In Progress Staff	
163	SPP Staff and members to prepare for discussion on scope standardization and prioritization of discussion items.	April 21st, 2016	In Progress Staff/Members	
165	ESWG to review the assumed benefit of mandated reliability projects	May 13th, 2016 RARTF	In Progress ESWG	
166	ESWG to review the impacts of using the system reconfiguration hybrid approach for the Assumed Benefit of Mandated Reliability Projects	May 13th, 2016 RARTF	In Progress ESWG	
167	ESWG to review the classification of projects in the ITP process	May 13th, 2016 RARTF	In Progress ESWG	
168	Staff and the ESWG to evaluate the issues seen in the DC to AC model	May 18th-19th,	In Progress	

	conversion process.	2016	Staff/ESWG	
172	Staff to develop examples and language for tackling synergies of powerflow and economic generation data.	June 16th, 2016	In Progress Staff	October 20th: ESWG approved a methodology for the ITP standard scope. Discussions should continue with SAWG for coordination of methodology, as appropriate.
173	Staff to develop a process for annual update of the economic model with vendor data.	June 16th, 2016	In Progress Staff	
174	Staff to develop criteria and methodology to developing resource plans absent a software tool.	June 16th, 2016	In Progress Staff	
177	Staff to develop a checklist of decision points for development of the ITP standard scope.	July 21st, 2016	~~In Progress~~Complete Staff	September 15th: Include timeline for bringing items to each meeting. October 20th: Still vetting internally. Should be ready for member consumption prior to November meeting. November 16th: Will be discussed in meeting.
182	SPP Staff to post models and data utilized for the 2017 ITP10 side-bar analysis when complete.	September 15th, 2016	~~In Progress~~Complete Staff	
183	SPP Staff to perform the outage analysis to determine the appropriate APC benefit % to utilize in the mitigation of transmission outages benefit metric in the first part of 2017.	September 15th, 2016	In Progress Staff	
184	Stakeholders to submit comments on the chronic operational issues criteria to SPP Operations (Will Tootle, wtootle@spp.org) within the next couple of weeks.	October 20th, 2016	~~In Progress~~Complete Stakeholders	

Southwest Power Pool
Economic Studies Working Group
Charter
October 27th, 2015

PURPOSE

The Economic Studies Working Group (ESWG) advises and assists Southwest Power Pool (SPP) Staff in the determination of the appropriate data, planning methods and processes to be used in the development and evaluation of economic transmission expansion options for the SPP region. The ESWG will be responsible for data, sources, models, economic planning methodology, timing and implementation, application, economic parameters and metrics to be used in the development and evaluation of economic expansion options in the SPP region. The ESWG will also review the economic planning processes used by SPP Staff and offer proposals for improvement of these processes. The ESWG will be responsible for all economic modeling parameters and data for the SPP region, and will conduct as needed updates to all data for the stakeholders on a regular basis as appropriate for regional planning needs. Additionally, the ESWG will be responsible for ensuring that third party consultants contracted by the SPP have access to the most appropriate, updated data.

Commented [KA1]: Is this necessary?

SCOPE OF ACTIVITIES

In carrying out its purposes, the ESWG will:

1. Provide oversight, data inputs and review, as appropriate, of economic planning studies performed by the SPP, including but not limited to:
   - Integrated Transmission Planning (ITP) – provide input into the economic portions of the ITP process
   - Balanced Portfolio – Provide guidance to the CAWG on input assumptions and modeling techniques used in the Balanced Portfolio analysis
   - High Priority – support other high priority economic studies, as applicable
   - Coordinated System Planning – provide input into economic studies performed in coordination with neighboring regions or entities
   - Regional Cost Allocation Review (RCAR) – provide input into the RCAR analysis and provide guidance to the Regional Allocation Review Task Force (RARTF), as needed
   -

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2. Provide oversight of the economic study process performed by the SPP, including but not limited to, economic transmission plan development, project interaction and the overall economic planning process

~~3. Provide oversight of and review Loss of Load Expectation (LOLE) studies performed by the SPP~~

~~5.~~3. Provide input to the SPP in evaluation of the impact of market mechanisms on planning studies

~~6.~~4. Establish study standard assumptions for economic analysis; determine, update and vet the necessary data and inputs required to model, study, and evaluate economic alternatives

~~7.~~5. Define and update any terms used in the economic transmission planning process, including data, metrics and assumptions that provide clear understanding to conduct economic studies for SPP

~~8.~~6. Identify, review and modify the metrics for overall quantification and break-out of economic impacts beyond adjusted production cost savings

~~9.~~7. Review the solution techniques and provide recommendations for improvements and/or alternatives

~~10.~~8. Update and maintain the economic planning process documentation to provide controls for economic planning in SPP

~~11.~~9. Provide updates to the MOPC on the status and progress of economic studies and planning in the SPP

REPRESENTATION

The ESWG membership will consist of up to ~~the following~~seventeen voting members (including the Chariman). The ESWG will have one non-voting Regulatory Liaison member.~~:~~

~~17 Voting members~~

- ~~5 Transmission Owning~~
- ~~5 Transmission Using~~
- ~~5 Generation~~
- ~~2 Other~~

~~And 1 non-voting Regulatory Liaison member.~~Members of the ESWG shall have experience and knowledge in one or more of the following areas:

- Economic Analysis
- Energy markets
- Transmission Planning
- Planning and Forecasting
- Generation
-

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DURATION

Permanent.

REPORTING

The ESWG reports to the Market and Operations Policy Committee.

Other Notes:
In light of FERC Orders 888 and 889 and the group composure of transmission and generation parties, the ESWG will have to observe the Standards of Conduct outlined in FERC Order 889. As such, there may be topics discussed by the ESWG that are privileged and confidential. Under such an event, appropriate measures will be taken to ensure that no Standards of Conduct are violated, including but not limited to, closed meetings, closed sessions, etc. Members and participants will be required to adhere to SPP's Nondisclosure Agreement.

ITP Scope Standardization – Wind Pricing

ESWG

12/08/16

Wind Modeling – Economic Parameters

- PROMOD has two primary economic modeling parameters impacting wind dispatch, curtailment, and production cost
  - Curtailment price
  - Variable O&M
- SPP currently uses $8/MWh for both of these, for all wind units

Wind Curtailment Price

- Defines the trigger price at which wind will curtail
- If curtailment price is $8/MWh, wind will curtail if the LMP at the unit drops to $7/MWh
  - If the LMP stays above $8/MWh, the wind dispatch will follow the defined hourly profile for that unit
  - The curtailment price impacts dispatch/curtailment, but does not impact unit production costs
- Staff analyzed historical offer prices in the Integrated Marketplace, 2014 – 2016
  - After removing extreme outliers, -$23/MWh was the average offer price
  - There is some variability; some prices are higher, even above zero, while many offers are around -$60/MWh, due to the PTC + PPA price
- Option 1: Use -$23/MWh for curtailment price, which would account for a PTC
- Option 2: Use $0/MWh for curtailment price, which does not account for a PTC
  - ABB recommendation
  - Staff recommendation

Wind Variable O&M

- Defines the operating cost per MWh
- Does not impact dispatch/curtailment, but directly impacts production cost and APC benefit
- Three ideas for defining this
  - Use approximate operating cost (~$0/MWh)
  - Use approximate PPA price
  - Use some kind of a compromise between the operating cost and PPA price (such as $8/MWh, or higher)
- Staff recommends using $8/MWh as variable O&M for wind

Appendix

PTC ($/MWh)

All values shown in Present Value ($/MWh)		PTC	Wind Farm Construction														
	Year		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Jan. 1, 2020
	2006	100%	$ 23														
	2007	100%	$ 23	$ 23													
	2008	100%	$ 23	$ 23	$ 23												
	2009	100%	$ 23	$ 23	$ 23	$ 23											
	2010	100%	$ 23	$ 23	$ 23	$ 23	$ 23										
	2011	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23									
	2012	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23								
	2013	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23							
	2014	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23						
	2015	100%	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23					
Steps Down	2016	100%		$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23				
	2017	80%			$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18			
	2018	60%				$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14		
	2019	40%					$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	
	2020	0%						$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2021	0%							$ 23	$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2022	0%								$ 23	$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2023	0%									$ 23	$ 23	$ 23	$ 18	$ 14	$ 9	0
	2024	0%										$ 23	$ 23	$ 18	$ 14	$ 9	0
	2025	0%											$ 23	$ 18	$ 14	$ 9	0
	2026	0%												$ 18	$ 14	$ 9	0
	2027	0%													$ 14	$ 9	0
	2028	0%														$ 9	0
END	2029	0%															0

NOTE: After construction begins the tax payer has 4 years to complete construction, e.g. a wind facility starting construction in 2019 could begin operation in 2023, and the PTC would expire in 2033.
https://www.irs.gov/irb/2016-23_IRB/ar07.html