ORGANIZATION OF MISO STATES, INC.
Board of Directors Special Meeting
Conference Call Minutes
March 14, 2013

Approved April 18, 2013

Kari Bennett, President of the Organization of MISO States, Inc. (OMS), called the March 14, 2013 Special meeting of the OMS Board of Directors to order via conference call at approximately 1:00 p.m. (CDT). The following board members or their proxies participated in the meeting:

John Colgan, Illinois
Kari Bennett, Indiana
Libby Jacobs, Iowa
Talina Matthews, proxy for Linda Breathitt, Kentucky
Eric Skrmetta, Louisiana
Bill Bokram, proxy for Orjiakor Isiogu, Michigan
David Boyd, Minnesota
Brandon Presley, Mississippi
Robert Kenney, Missouri
Kirk Bushman, Montana
Phil Movish, proxy for Cynthia Hedge-Morrell, City of New Orleans
Brian Kalk, North Dakota
Greg Rislov, proxy for Gary Hanson, South Dakota
Richard Greffe, proxy for Ken Anderson, Texas
Eric Callisto, Wisconsin

Absent
Manitoba

Agency members participating
Linda Wagner – Illinois
David Johnston – Indiana
Melissa Watson, Paul Zimmering – Louisiana
Angie Butcher, Jessica Govindan – Michigan
Chad Allen – Mississippi
Bill Booth, Tom Stratton – New Orleans
Jerry Lein – North Dakota
Julie Urban – Wisconsin

Others on the call
Julie Mitchell, Bill Smith – OMS Staff
Valerie Lemmie, Bob Pauley - EISPC

The directors and proxies listed above established the necessary quorum for the meeting of at least nine directors being present.

Approval of Minutes from the February 14 Board Meeting

The minutes of February 14, 2013 were accepted as submitted.

Treasurer's Report of February 2013

There were no questions regarding the February 2013 Treasurer's report. It was accepted as distributed.

Review of the February 28, 2013 Executive Committee Meeting

The meeting was cancelled.

Administrative Report

The Executive Director's written report was distributed prior to the meeting. Bill Smith highlighted the following:

- Grid School was the previous week. OMS sent a full set of representatives.
- A revised OMS calendar was distributed to members. The work group chairs and key staff meeting will now come before the Executive Committee meeting on the calendar; and the Executive Committee will now meet two weeks before the OMS Board meeting.
- The 7th Circuit will hear oral arguments on the cost allocation case concerning MISO MVPs in Chicago.

BUSINESS

1. MISO Advisory Committee

- The final agenda for the March AC meeting has not yet been distributed. The March meeting will be by conference call. Items anticipated being on the agenda are: update from MISO on Order 1000 Interregional Compliance filings; a potential action item from the Steering Committee on a minor charter revision; a call for nominations to the Nominating Committee of the MISO Board of Directors.
- The April meeting will discuss the next hot topic, which is on market enhancement. Bill Bokram provided board members a preview of the topic. The issue was assigned to the Markets and Tariffs Work Group for a response.

2. Planning Advisory Committee

- Jessica Govindan highlighted the PAC Summary and introduced the PAC motions.
- Julie Urban gave the MTEP 13 update and there was discussion with the Board about weighting scenarios.

3. Associate Membership Request: Mississippi Public Utilities Staff

- An OMS membership request was presented.

Kari Bennett moved that the OMS Board accept the Mississippi Public Utility Staff as an associate member of the Organization of MISO States. Brandon Presley seconded the motion and gave some background to the Board on the structure of the Mississippi Commission and staff. The motion passed by unanimous voice vote.

4. Update: Eastern Interconnection Planning Process

- A written report was submitted. Bob Pauley and Valerie Lemmie provided an update on current activity

5. Action Item: OMS Answer in Docket ER13-708, Section 205 Filing Authority

- This comment was discussed in closed session, pursuant to Article XIII of the OMS Bylaws.

The document was approved with the following members supporting: Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, City of New Orleans, North Dakota, South Dakota, Texas, and Wisconsin. Manitoba did not participate.

Updates and Work Group Status Reports

Demand Response WG
- Written report;

Transmission Cost Allocation WG
- Written report;

Markets and Tariffs WG
- Written report;

Resources WG
- Written report;

Regional Planning WG
- Written report;

Governance and Budget
- No report;

Modeling WG
- No report;

Seams WG
- Written report;

ADJOURNMENT

The public OMS Board of Directors meeting adjourned at 1:40 pm CDT.

The closed session was called to order at approximately 1:45 pm CDT and adjourned at 2:10 pm CDT.

OMS

Organization of MISO States
Report of the Treasurer
Dr. David C. Boyd, Minnesota Public Utilities Commission
to the
Board of Directors
Report for February 2013

CASH ON HAND

The beginning balance for the Wells Fargo Business Performance Savings Account as of February 1 was $25,168.92. Interest earned for this month was $0.97 and there was no other account activity. The February 28, 2013 ending balance was $25,169.89.

The beginning book balance for the Chase Bank One Checking account as of February 1 was $41,183.13. The total disbursements from the checking account for February 2013 were $49,457.71. Deposits, interest and adjustments were $60,000.57. As of February 28, 2013, the checking account bank balance was $74,088.80 (13 checks remain outstanding) and the book balance was $51,725.99.

The total savings and checking account (book) balances as of February 28, 2013 is $76,895.88.

TREASURER'S REPORT
Organization of MISO States
February 28, 2013

Wells Fargo Business Performance Savings Account

Book Balance as of 1/31/13				$ 25,168.92
2/28/2013	DEP	Interest on Savings		$ 0.97
Business Performance Savings Account Balance at 2/28/2013				$ 25,169.89

Chase Bank One Commercial Checking with Interest

Book Balance as of 1/31/13				$ 41,183.13
2/4/13	ACH	Midwest ISO	$ 60,000.00	
1/31/13	DEP	Interest on checking	$ 0.57	
		Total Deposits		$ 60,000.57

Checks and Charges

Date	Check #	Descriptions		
2/13/13	E-Pay	Chase Bank Card	$ 2,864.81	
2/11/13	EFT	Paychex Invoice (Jan. P/R)	$ 101.00	
2/11/13	4257	100 Court Investors - Office Rent & Pkg (Mar.)	$ 1,724.03	
2/11/13	4258	C. Devon - Travel Exp. - 1/28-1/29	$ 272.49	
2/11/13	4259	Combined Systems Technology - Symantec renewal - 1 year	$ 188.89	
2/11/13	4260	The Company Corporation (Registered agent svc. - 1 year)	$ 150.00	
2/11/13	4261	D. Lofftus - Travel Advance - March Grid school	$ 682.40	
2/11/13	4262	Diversified Management Services (6 mo. web hosting fee)	$ 316.99	
2/11/13	4263	J. Govindan - Travel Exp. - 1/29-1/30	$ 334.27	
2/11/13	4264	K. Bushman - Travel Advance - March Grid school	$ 747.90	
2/11/13	4265	Triplett Office Essentials - paper	$ 94.09	
2/11/13	4266	WI PSC (J. Urban - Travel Exp. 1/29-1/31)	$ 275.28	
2/13/13	4267	CenturyLink - office phone, fax, DSL, Jan. LD calls	$ 259.05	
2/13/13	4268	Ryun, Givens & Co. PLC - 2012 Tax form prep (1099s, etc.)	$ 45.00	
2/19/13	4269	A. McKinnie - Travel Exp. - 1/30-1/31	$ 298.88	
2/19/13	4270	B. Roads - Travel Exp. - 11/29-11/30	$ 427.15	
2/19/13	4271	WI PSC (R. Pilo - Travel Exp. - 1/29-1/31)	$ 558.58	
2/21/13	4272	B. Smith - WiFi & Travel Exp. 2/2-2/7	$ 222.53	
2/21/13	4273	Conference Suite - conf. calls, Board-Exec comm.	$ 1,409.72	
2/21/13	4274	Customized Energy Solutions - Jan. subscription	$ 3,500.00	
2/21/13	4275	Michigan State Univ. - Grid School 2013	$ 13,995.00	
2/25/13	4276	A. Schmelzer - reimb. for supplies - OMS open house	$ 23.30	
2/25/13	4277	B. Smith - Travel Exp. - 2/18-2/22	$ 83.06	
2/25/13	4278	WI PSC (J. Urban - Travel Exp. 2/11-2/12)	$ 368.65	
2/28/13	4279	C. Devon - Travel Exp. - 2/18-2/21	$ 411.72	
2/28/13	4280	W. Cecil - Travel Exp. - 2/19-2/22	$ 670.98	
2/28/13	4281	W. Bokram - Travel Exp. 2/19-2/21	$ 812.02	
2/27/13	EFT	Paychex Payroll net pay (ck.nos. 504-506)	$ 10,216.30	
2/28/13	EFT	Paychex Payroll Taxes	$ 5,268.79	
2/28/13	507	MG Trust (401(k))	$ 2,339.83	
2/28/13	508	MG Trust (401(k))	$ 693.01	
2/28/13	509	MG Trust (401(k))	$ 101.99	

Total Disbursements - Checks and Charges	$ 49,457.71	
CHECKING ACCOUNT BALANCE at 2/28/13		$ 51,725.99

TOTAL Certificates of Deposit, Savings and Checking Account Balances as of: 2/28/13	$ 76,895.88

CHASE CHECKING ACCOUNT RECONCILIATION

Bank Balance 2/28/13			**$**	**74,088.80**
Less Checks Outstanding				
	Check #			
2/11/13	**4266**	**WI PSC**	**$**	**275.28**
2/19/13	**4269**	**A. McKinnie -**	**$**	**298.88**
2/19/13	**4270**	**B. Roads**	**$**	**427.15**
2/19/13	**4271**	**WI PSC**	**$**	**558.58**
2/21/13	**4273**	**Conference Suite**	**$**	**1,409.72**
2/21/13	**4275**	**Michigan State Univ. - Grid School 2013**	**$**	**13,995.00**
2/25/13	**4278**	**WI PSC**	**$**	**368.65**
2/28/13	**4279**	**C. Devon**	**$**	**411.72**
2/28/13	**4280**	**W. Cecil**	**$**	**670.98**
2/28/13	**4281**	**W. Bokram**	**$**	**812.02**
2/28/13	**507**	**MG Trust (401(k))**	**$**	**2,339.83**
2/28/13	**508**	**MG Trust (401(k))**	**$**	**693.01**
2/28/13	**509**	**MG Trust (401(k))**	**$**	**101.99**
Total Outstanding Checks			**$**	**22,362.81**
Book Balance 2/28/13			**$**	**51,725.99**

OMS
Organization of MISO States

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OMS Executive Director Report
March 13, 2012 (Covering January and February)

FERC Actions

1. On February 4, the FERC denied a complaint by American Transmission Company concerning rights to participate in construction of CapX projects. Docket EL13-9. This decision turns on FERC's view that MISO's pre-Order 1000 tariff provisions constitute a Right of First Refusal, and that the CapX elements were separate projects.
2. On February 19, the FERC approved MISO's proposal to issue up to $100 million in long-term debt. Docket ES13-13.
3. On February 27, the FERC approved MISO's proposal to count energy efficiency improvements for resource adequacy purposes for four years. Docket ER13-669.
4. On March 4, the FERC issued an order accepting MISO's proposed System Support Resource provisions for the Escanaba plant to continue operations through June 2013 for system reliability reasons. Docket ER13-37. Applicability of these provisions to other plants will be under discussion among stakeholders in coming months.
5. Hearings will begin before FERC ALJ Peter Young on April 2 in Docket ER12-715, relating to the level of exit charges for Duke and FirstEnergy's departure form MISO.
6. Oral arguments on cost allocation of Multi-Value Projects will be held on April 10 at the US Court of Appeals, 7th Circuit, in Chicago.

MISO Filings

1. On February 1, MISO filed modifications to its Tariff to facilitate Load Serving Entities (LSEs) that integrate into the MISO Balancing Authority Area in meeting such LSEs' new Resource Adequacy Requirements (RAR). Docket ER13-868.

2. On March 5, MISO responded to pleadings related to capacity deliverability between MISO and PJM following its January 3 Request for Expedited Issuance of Order. Docket AD12-16.
3. On March 7, MISO and PJM proposed two revisions to the Joint Operating Agreement (Congestion Management Process). One would calculate Market Flows using the same Per Generator Methodology currently used to calculate Firm Flow Entitlements. Docket ER13-1052. The other would calculate Market Flows using a method to scale loads for tagged import transactions in a manner similar to the methodology currently used to scale generation for tagged export transactions. Docket ER13-1054.
4. On February 15, MISO and Entergy Services, Inc., submitted Attachment O templates that will establish formula rates for the Entergy Operating Companies' recovery of their transmission revenue requirements in the proposed four transmission pricing zones of the MISO. Also filed were corresponding revisions to Schedule 7 (Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service); Schedule 8 (Non-Firm Point-to-Point Transmission Service); Schedule 9 (Network Integration Transmission Service); Schedule 26 (Network Upgrade Charge from Transmission Expansion Plan); and the preamble to Attachment O to make references to the four transmission pricing zones and the company-specific Attachment O templates for the Entergy Operating Companies in connection with their proposed integration into MISO. Docket ER13-948.
5. On February 22, MISO answered comments and protests filed in t in response to MISO's December 28 proposed Tariff revisions regarding Long-Term Transmission Rights, Auction Revenue Rights, and Financial Transmission Rights for the integration of the Second Planning Area into MISO. Docket ER13-665.
6. On February 25, MISO intervened without comment in the petition for declaratory order filed by the City of New Orleans, the Mississippi Public Service Commission and the Arkansas Public Service Commission requesting a determination as to whether the Entergy Operating Companies' proposed avoided cost calculation methodology satisfies the Public Utility Regulatory Policies Act of 1978. Docket EL13-43.
7. On February 28, MISO filed an Amended Settlement Agreement relating to OMS filing rights. MISO also responded to various comments. The original agreement was filed on January 4. Docket ER13-708.

8. On February 28, MISO filed revisions to Schedule 27 (involving Real-Time Offer Revenue Sufficiency Guarantee Payment and Day-Ahead Margin Assurance Payment) to address certain gaming risks relating to Offers for Ancillary Services. Docket No. ER13-1004.

OMS / MISO Activity

1. The Public Staff of the Mississippi PSC has requested associate OMS membership. The request will be presented to the OMS Board on March 14.
2. OMS representatives participated in a Black Sea Regulatory Initiative Regional Workshop February 13-14. A Joint Coordinating Meeting was also held on February 15 with the corresponding group of Transmission System Operators. A further workshop is planned for early June 2013.

Public Relations

1. Presentations:
   - Bill Smith outlined OMS work to the ERSC Working Group on January 17.
   - Bill Smith gave a presentation on Transmission Planning to Grid School, sponsored by the Michigan State University Institute for Public Utilities on March 5.
   - On March 7, Bill Smith met with the North Dakota PSC

2. Pending speaking/meeting invitations:
   - Bill Smith will meet the Montana PSC on March 22 to review OMS activities.
   - Bill Smith is scheduled to speak to a US Energy Association conference ion May 15.

Upcoming dates:

- Next OMS Board of Directors meeting: March 14, 2013, at 1:00 pm CT
- Next OMS Executive Committee meeting: April 4, 2013, at 1:00 pm CT
- Future OMS Board meetings: April 18, May 21

- OMS Executive Committee meetings: May 2, May 30.
- Next OMS meetings with IMM: April 3, 2:30 CT

OMS 2013 Meeting Calendar - with suggested changes as of March 8, 2013

OMS Board of Directors	OMS Executive Committee	OMS WG Chairs & Key Staff	MISO Advisory Committee	MISO Planning Advisory Committee	Other Meetings of Interest	OMS -IMM Conference Calls
Thursday conference call meetings, unless noted	*Thursday conference call meetings, unless noted*	*Friday conference calls, unless noted*	*Wednesday meetings in person or conference calls*	*Wednesday meetings in Carmel, unless noted*		*Wednesday calls every other month at **2:30 pm** Central*
Jan 17 at 1:00 pm CST	**Jan 31** at 1:00 pm CST Cancelled	**Jan 4** at 9:30 am CST	~~**Jan 23** – conf call~~ Cancelled	**Jan 30**	**Jan 10-12** -MARC Commissioners Austin, TX	**Jan 30**
Feb 14 at 1:00 pm CST	~~**Feb 28** at 1:00 pm CST~~ Cancelled	**Feb 1** at 9:30 am CST	**Feb 20** – New Orleans	**Feb 27**	**Feb 3-7** – NARUC Winter Mtgs - Wash DC	No Call
Mar 14 SPECIAL mtg at 1:00 pm CDT						
~~**Mar 21** at 1:00 pm CST~~ Cancelled	**Apr 4** at 1:00 pm CDT	**Mar 1** at 9:30 am CST	**Mar 27** conf call	**Mar 20**		**Apr 3** (for Mar)
Apr 18 at 1:00 pm CDT	**May 2** at 1:00 pm CDT	**Mar 29** at 10 am CDT	**Apr 24** - Carmel	**Apr 17**	**Apr 2-4** – OPSI Spring mtg – Indianapolis	No Call
May 16 at 1:30 pm CDT	**May 30** at 1:00 pm CDT	**Apr 26 at 10** am CDT	**May 22** – conf call	**May 15**		**May 29**
Jun 12 (Wed) **SPECIAL mtg** at 12:00 pm CDT (after MARC -Little Rock)					**June 8-12** – MARC Annual mtg –Little Rock, AR	
Jun 13 at 1:00 pm CDT	**Jul 2** (Tue) at 1:00 pm CDT	**May 24 at 10** am CDT	No June meeting	**Jun 26**	**June 19** - MISO Annual Stakeholder mtg – Grand Traverse, MI	No Call
Jul 18 at 1:00 pm CDT	**Aug 1** at 1:00 pm CDT	**Jun 28 at 10** am CDT	**July 24** – conf call	**Jul 31**	**July 21-24** – NARUC Summer mtg – Denver	**Jul 31** *tentative*
Aug 15 at 1:00 pm CDT	**Sep 5** at 1:00 pm CDT	**Jul 26** at 10 am CDT	**Aug 21** – St. Paul	**Aug 28** – St. Paul		No Call
Sep 19 at 1:00 pm CDT	**Oct 3** at 1:00 pm CDT	**Aug 23** at 10 am CDT	**Sep 25** – conf call	**Sep 18**		**Oct 2** (for Sep) *tentative*
Oct 17 at 1:00 pm CDT	**Oct 31** at 1:00 pm CDT	**Sep 27** at 10 am CDT	**Oct 23** - Carmel	**Oct 16**	**Oct 6-9** – OPSI Annual mtg – Raleigh, NC	No Call
Oct 22 (Tue) at 9:00 am **EDT** – OMS Annual Mtg - Carmel		**Oct 25**at 10 am CDT				Presentation at Annual mtg
Nov 14 at 1:00 pm CST	**Nov 26** (Tue) at 1:00 pm CST	**Nov 22** at 10 am CST	**Nov 20** – conf call	**Nov 13**	**Nov 17-20** - NARUC Annual mtg - Orlando	No Call
Dec 5 at 1:00 pm CST	**Dec 19** at 1:00 pm CST	**Dec 13** at 10 am CST	**Dec 11** - Carmel	**Dec 18**		**Dec 18** *tentative*

(9) OMS Office Holidays in 2013 (plus an additional Holiday – TBD)
New Year's Day – Tuesday, January 1
Memorial Day – Monday, May 27
Independence Day – Thursday, July 4
Labor Day – Monday, September 2
Thanksgiving and Day After– Thursday & Friday, November 28-29
Christmas Eve and Christmas Day – Tuesday & Wednesday, December 24- 25

OMS-MISO Quarterly Calls re: MISO's AFCWG, OWG and OPWG
1st Quarter – Fri, **Feb 8** at 1:00 pm **EST**
2nd Quarter – Fri, **May 10** at 1:00 pm **EDT**
3rd Quarter - Fri, **Aug 9** at 1:00 pm **EDT**
4th Quarter – Fri, **Nov 8** at 1:00 pm **EST**

2/27/13 PAC Summary

- **Upcoming feedback deadlines:**
  - Out of Cycle Proposal (due 3/8)
  - Project Status Update (due 3/8)
  - Market Participant Funded Upgrades (due 3/8)
  - HVDC Interconnection Draft (due 3/13)
  - MTEP 13 Futures Survey for weights (TBD)
- **What to expect at upcoming Planning meetings:**
  - March 20th PAC:
    - Voting on Market Participant Funded BPM Language, Transmission Planning BPM Language (multi-motions)
    - More discussion on OOC Proposal and Project Status Update BPM language
    - MTEP 13 progress update
    - System Support Resource Discussion
  - April 17th PAC:
    - Results for sector weights of MTEP 13 futures

- **MTEP 13 Futures:**
  - MISO provided a final review of the MTEP 13 futures narratives and key assumptions as approved by most sectors from email vote following the January PAC meeting. MISO provided additional information, demonstrating the results of the new gas methodology on future gas prices for each future. MISO will be sending around a survey for sectors to weigh the 5 futures, as we have done in years past. MISO hopes to have results available in time for the April PAC meeting. Please refer to the PAC presentations for more details.

- **Merchant HVDC Interconnection Update:**
  - MISO presented a draft procedures document describing the proposal for Merchant HVDC interconnections. The draft document is partially complete and MISO will be putting together more materials. They hope to have Tariff language ready to file in June/July of 2013 and will be bringing language back to the PAC for stakeholder input over the next several months. There was a concern with how to apply this new procedure, when it's finally vetted with those HVDC lines currently in the queue (interregional projects currently in the SIS study stage). MISO said that is still something they need to figure out.
    - Feedback due: 3/13

- **Out of Cycle Review Straw Proposal:**
  - Please refer to the January 30, 3013 PAC summary for detailed about the proposal. MISO continued discussion of stakeholder comments on the proposal and corresponding BPM language. Within the presentation materials, MISO provided redline edits to both the Transmission Planning BPM for Out of Cycle Review (Section 6), as well as Attachment FF language within the Tariff for related OOC language. However, it was discussed that the Transmission Owners Agreement, Appendix B also will require substantive changes to reflect the new proposal. MISO will need to discuss with the TOs changing the TOA language.
    - Feedback Due: 3/8 (OMS RPWG submitted comments)

- **Project Status Update Discussion:**
  - MISO discussed the updated project status proposal, which would incorporate a milestone approach to requiring certain eligible transmission projects to provide more detailed information in their quarterly project status updates. There was a lot of discussion around this topic. In

particular, MISO's new inclusion of four milestones corresponds to key action-oriented events that ultimately lead to a project's construction. However, it was revealed that the approach still needs work, because MISO's milestone approach, as presented, leaves some gaps in time when one would expect to have additional updated information in advance of key decision making events (e.g., MISO BOD approval, beginning project construction, etc). March PAC meeting should include continuing discussions on this topic.

- Feedback Due: 3/8 (OMS RPWG submitted comments)

- **Order 1000 Interregional Planning Update:**
  - FERC granted a 90-day extension for all RTO/ISO to file their respective interregional compliance filings. Now July 10, 2013
  - *MISO – MAPP* → reached an agreement on model and data exchange; following close to what MISO has done with SPP and PJM, with difference being issues review will occur biennially rather than annually. Next meeting 3/21. Expecting to file earlier than July 2013.
  - *MISO – SPP* → There might not be agreement on everything, however they will file at least what has been agreed to (interregional planning processes and cost sharing for 345kV and above MEPs). Next meeting 3/29. Expecting to file mid-May 2013.
  - *MISO – PJM* → MISO and PJM TOs agree to justify existing cross-border cost allocation methods as Order 1000 compliant. They continue to discuss the redline edits within the JOA for other compliance issues (i.e., defining role of IPSAC) Next meeting 3/13. Expecting to file in April 2013 still.
  - *MISO – SERTP* → MISO and SERTP have begun discussing the timeline for addressing Order 1000 compliance. They filed on February 20th for a 120-day extension.

- **Additional Topics –** please refer to the PAC meeting materials for more information on the following:
  - Market Participant Funded upgrade language – last minute stakeholder comments to MISO before February PAC meeting lead to a delay in voting on this item. MISO was going to take the suggested comments to their legal department to see if they were valid and come to March PAC meeting with their findings. The concern is that some of the comments provided would not be eligible for inclusion in the BPM language because they were out of the scope of the Tariff. So, until the Tariff reflects the comments, the BPM cannot include them. Please refer to the PAC meeting materials for details. They have also asked stakeholders for any additional concerns, particularly about the last minute comments. Potential voting item for March PAC.
  - Electric & Natural Gas Coordination Task Force update – MISO staff provided a brief update about the Task Force (TF). They mention FERC staff have been participating in these meetings a lot. Chair will post summary of these meetings, making sure to note what FERC staff are saying. A big topic of discussion has been on communication of what and when something will disrupt the natural gas system and how effective coordination between the gas and electric systems can be reached. Staff will continue to provide updates to the PAC.

For meeting materials, click here. **Next PAC meeting 3/20**

Prepared by J Govindan

3/12/2013

PLEASE SUBMIT COMMENTS BY Friday, March 29, 2013

The weights will be used to identify the relative impact that each scenario will hav
and the calculation of benefit-to-cost ratios (B/C) of economic projects. The weig
views about the probability that each scenario

Sector Name:

MTEP13 Future	Sector Weight
Business as Usual	0%
Robust Economy	0%
Limited Growth	0%
Generation Shift	0%
Environmental	0%
Total %	0%

ve on the results from the PROMOD analyses
hts should be assigned based on the sectors'
will occur.

Motion to the Planning Advisory Committee – March 20, 2013

The Planning Advisory Committee (PAC) recommends that MISO adopt proposed updates to the Transmission Planning Business Practices Manual (BPM) reflecting language for evaluating Market Participant funded upgrades, as discussed in the March 20, 2013 PAC meeting.

Motions for Planning Advisory Committee (PAC) – March 20, 2013

Motion 1:
The Planning Advisory Committee (PAC) recommends that MISO adopt proposed updates to the Transmission Planning Business Practices Manual (BPM) reflecting language on Maintenance Period Studies, as approved by the Planning Subcommittee (PSC) on February 26, 2013, and provided for the March 20, 2013 PAC meeting.

Motion 2:
The Planning Advisory Committee (PAC) recommends that MISO adopt proposed updates to the Transmission Planning Business Practices Manual (BPM) reflecting language on PRC-023 Transfer Relay Loadability, as approved by the Planning Subcommittee (PSC) on February 26, 2013, and provided for the March 20, 2013 PAC meeting.

Motion 3:
The Planning Advisory Committee (PAC) recommends that MISO adopt proposed updates to the Transmission Planning Business Practices Manual (BPM) reflecting language on FAC-013 Transfer Capability for the Planning Horizon, as approved by the Planning Subcommittee (PSC) on February 26, 2013, and provided for the March 20,2 013 PAC meeting.

Motion 4:
The Planning Advisory Committee (PAC) recommends that MISO adopt proposed updates to the Transmission Planning Business Practices Manual (BPM) reflecting language on FAC-010 System Operating Limit for the Planning Horizon, as approved by the Planning Subcommittee (PSC) on February 26, 2013, and provided for the March 20,2 013 PAC meeting.

PUBLIC UTILITIES STAFF

CHAD J. REYNOLDS
GENERAL COUNSEL

MICHAEL MCCOOL, DIRECTOR
WATER & SEWER DIVISION

CHRISTOPHER GARBACZ, DIRECTOR
ECONOMICS & PLANNING DIVISION

VIRDEN C. JONES
EXECUTIVE DIRECTOR

RANDY TEW, DIRECTOR
ADMINISTRATIVE SERVICES DIVISION

WENDY COLLINS, DIRECTOR
ELECTRIC, GAS & COMMUNICATIONS

DONNA CHANDLER, DIRECTOR
COMMUNICATIONS SECTION

March 4, 2013

VIA EMAIL

Commissioner Kari Bennett, President
Organization of MISO States
100 Court Avenue
Des Moines, IA 50309

Dear Commissioner Bennett:

Please accept this letter as an official request by the Mississippi Public Utilities Staff (MPUS or Staff) to become an Associate Member of the Organization of MISO States (OMS).

MPUS was established by the Mississippi Legislature as an independent state agency completely separate and independent from the Mississippi Public Service Commission (MPSC). The Staff, by law, represents the broad interests of the State of Mississippi by balancing the respective interests of residential, commercial and industrial ratepayers; the state, its agencies and departments; and the public utilities subject to the MPSC's jurisdiction.

The primary functions performed by the Staff for the MPSC are investigative and advisory in nature. MPUS participates in all matters before the MPSC as a party, an advisor or both. It makes recommendations regarding all MPSC proceedings affecting the rates, services, investments and service areas of any public utility when deemed necessary and in the public interest. For more information about MPUS, please refer to its web site at www.mpus.ms.gov.

Therefore, the Staff hereby requests that the OMS Board of Directors approve the Mississippi Public Utilities Staff as an Associate Member in OMS.

Respectfully submitted,

Virden Jones
Executive Director

cc: Bill Smith, Executive Director

UPDATE
Organization of MISO States
March 2013

Studies and Whitepapers

Work continues by Argonne National Laboratory on the Energy Zones mapping tool. Currently, over 216 data layers are included in the tool. Argonne hopes to include the Western Interconnection and the ERCOT in the final tool. Argonne would welcome people to use the software and would be amenable to attending an OMS meeting to demonstrate the Energy Zones mapping tool.

Astrape analysis of the Economics of Resource Adequacy was completed in February (copy attached). Astrape noted several areas that warrant additional research. EISPC will consider those at a later date.

Navigant's Studies of Demand Response, Energy Efficiency, Customer-Owned Generation using Renewable Energy, Customer-Owned Generation using Fossil Fuels, Energy Storage, and Smart Grid are scheduled to be completed in about 2 weeks. There has been companion work with Georgia Tech and Oak Ridge National Laboratory that is on the EISPC website.

Studies on the potential for nuclear and coal-fired generation are on schedule to be completed in June 2013.

Requests for Proposals were issued in the last few days for:

1. A Long-Term Study of the Natural Gas and Electric Infrastructure Requirements. In addition to the Study, a Whitepaper will be produced that is intended to help states better understand the increased interdependencies of natural gas and electricity as well as the challenges to planning the natural gas and electric industry of the future. We intend to have a kick of meeting in late May or sometime in June that will include representatives from the Natural Gas and Electric Industries (hopefully including the Midwest ISO) as well as regulatory agencies and others that have an interest in the ramifications for increased use of natural gas by the electric industry. We have also invited our counterparts in the Western Interconnection and ERCOT to participate primarily because the natural gas industry infrastructure is national. This Study is expected to be completed in July 2014.

2. Studies using Probabilistic Risk Analysis in evaluating transmission facilities in comparison to other resources. We hope to conduct one or more Case Studies with RTOs or other Planning Coordinators. There will also be a Primer (Whitepaper) to assist states in incorporating risk analysis into their transmission and resource planning processes. This Study is expected to be completed in July 2014.

EISPC's next meeting is in Philadelphia at the May 30 – 31.

N A R U C

National Association of Regulatory Utility Commissioners

EISPC

EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Request for Proposals to assist the Eastern Interconnection States' Planning Council (EISPC) Members with the preparation of a:

STUDY: Conduct Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection

Solicitation Number: NARUC-2013-RFP024-DE0316

WHITE PAPER: Develop a White Paper on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection

Solicitation Number: NARUC-2013-RFP025-DE0316

****PROPOSALS MAY BE SUBMITTED FOR EITHER THE STUDY OR THE WHITE PAPER, OR BOTH****

RELEASED: March 7, 2013

RESPONSES DUE FOR STUDY: April 06, 2013

RESPONSES DUE FOR WHITE PAPER: April 06, 2013

Grants & Research Department
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue NW, Suite 200
Washington, D.C. 20005

REQUEST FOR PROPOSALS TO ADDRESS

Solicitation Number: NARUC-2013-RFP024-DE0316

A STUDY ON LONG-TERM NATURAL GAS AND ELECTRIC INFRASTRUCTURE REQUIREMENTS OF THE EASTERN INTERCONNECTION

Part 1: Study on Long-Term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection

A. Introduction

This collaborative study[1] is intended to provide the Eastern Interconnection States Planning Council (EISPC) Members[2] and NARUC, the electric power industry, the natural gas industry, and others with a comprehensive analysis of the potential long-term infrastructure requirements for the electric and natural gas industries. The electric industry seems to be on the threshold of significant changes due, in large part, to environmental policy that may require significant increases in the use of natural gas as a generating fuel relative to other fuels. Additionally, the successful integration of intermittent resources such as wind power would benefit from additional natural gas generating facilities located near the wind resources. Fortunately, the natural gas industry has substantial new sources of supply and in diverse locations that may be well suited to meet the dispersed locational requirements of new electric facilities. However, there may need to be modifications to current operating and contracting practices of both the electric and natural gas industries to ensure that changes to gas and electric infrastructure are timely and cost-effective.

As with other NARUC / EISPC studies, this analysis is intended to provide insights to assist public and private policymakers but it is not intended to be used to support any specific project. The study will build on current analysis and perspectives of the industry experts to objectively discuss the most significant ramifications of various Futures with varying dependence on natural gas generating technologies in the context of all other electric resources, the demand for electricity and natural gas, environmental requirements, increased natural gas sources that may affect gas transportation, and other parameters.

While the ultimate objective would be to develop a theoretical "optimal" transmission and electric system predicated upon the build-out of the three hypothetical cases being used in the

[1] The Collaborative process shall be determined at a later date. However, NARUC / EISPC intends to include EISPC, EIPC, the natural gas industry, other elements of the electric industry such as American Public Power Association, National Rural Electric Cooperative Association, Edison Electric Institute, North American Electric Reliability Corporation, North American Energy Standards Board, and interested parties including academic institutions, NARUC / EISPC also hopes the Western States and ERCOT would participate. It is EISPC's hope that this process will include DOE's National Laboratories. EISPC is hopeful that the Federal Energy Regulatory Commission will be an active participant in the collaborative process; to the extent they deem possible.

[2] EISPC has extended an invitation to our counterparts in the Western Interconnection and ERCOT to collaborate in the Study and Whitepaper.

Eastern Interconnection[3]analysis and to combine that with the best available natural gas infrastructure analysis, we understand this may not be deemed to be feasible at this point. We understand it may not even be feasible to co-optimize the three illustrative transmission build-outs using co-optimization techniques. If, after consultation with the Subcontractor and those involved in the collaborative process, a determination is made that an effort to co-optimize electric and natural gas infrastructure is not currently feasible, the expectation would be a second best analysis would be conducted using the best available tools. The Subcontractor is expected to coordinate work with the natural gas industry, the Planning Coordinators and others in the Electric Industry, EISPC's Energy Zones effort, the Department of Energy and its National Laboratories. Again, we hope for substantial involvement by the FERC, NERC, and NAESB.

In a variety of forums, including those conducted by the FERC and NAESB, it appears there is a continuing need to foster communication and better understanding of the issues confronting the natural gas and electric industries in an effort to facilitate long-term resource planning. While the primary goal of this work is to better understand the potential ramifications of different natural gas and electric industry futures, the success of the effort is contingent on our collective efforts to advance communication and mutual understanding of the natural gas and electric industries.

B. Department of Energy Requirements

This study will be undertaken under Department of Energy agreement DE-OE-0000316, funded under the American Recovery and Reinvestment Act of 2009 (ARRA).

Respondents must be able to comply with the ARRA Award Terms and the core funding agreement with regards to transparency, reporting, financial management, and separate accountability for ARRA funding, lobbying exclusions, Davis-Bacon Act compliance and other areas. This RFP requires the subcontractor(s) to include on their SEFA information to specifically identify Recovery Act funding. This information is needed to allow the NARUC to properly monitor subcontractor(s) expenditure of ARRA funds as well as oversight by the Federal awarding agencies, Offices of Inspector General and the Government Accountability Office. NARUC will not enter into any contract or subcontract in connection with this Contract with a party that has been debarred or suspended from contracting with the Federal Government. Refer to Excluded Parties List System at https://www.epls.gov/. NARUC will require a certification indicating that the sub-recipient is not debarred or suspended from receiving federal funds and requiring notification to the NARUC if its status should change; https://www.bpn.gov/ccr/ – the sub-recipients is required to register in the CCR, including obtaining a Dun and Bradstreet Data Universal Numbering System (DUNS) number, and to keep the registration and number current.

Please be advised in order to comply with the lobbying restrictions of the core funding agreement from the Department of Energy no proposal may be intended to support lobbying efforts of

[3] Ibid

any kind (including advocating specific outcomes of federal agency regulatory activities) or be proposed with any of the aforementioned activities in mind.

C. Period of Performance

The period of performance for this award will be from May 3, 2013 to (no later than) June 30, 2014; unless approved by NARUC/EISPC and DOE. It is anticipated that successful Subcontractor(s) will be notified by April 22, 2013.

D. Funds Budgeted

The budget for the Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection shall not exceed $900,000 (nine hundred thousand dollars) unless otherwise approved by EISPC / NARUC, and the DOE. All bids shall contain a detailed budget estimate (please template in Section E).

E. Responding to the RFP

Please submit responses no later than April 6, 2013 to the RFP to Miles Keogh, NARUC's Director of Grants and Research, by email to mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org with the email subject:

Study on Long-Term Natural Gas and Electric Infrastructure Proposal

There is no specific limitation on page numbers or format, although brevity and completeness will aid the selection process. All questions regarding the RFP should be directed to Miles Keogh and Sharon Thomas by email as well. In responding to this RFP, the Subcontractor(s) must respond to the following sections:

- A detailed explanation of how the Subcontractor(s) will fulfill the requirements listed, by task, in the Scope of Work. For example, if research is required, what type of research methods would the Subcontractor(s) employ to complete the research?

- Detailed timelines / milestones with deliverables in order to fulfill the requirements listed, by task, in the Scope of Work.

- A detailed budget, similar to the format provided, that estimates the costs of fulfilling the terms of this Subcontract(s).

- A statement of qualifications, work experience and past projects by the Subcontractor(s) on topics similar to those in this RFP. Experience in multiple regions of the Eastern Interconnection should be highlighted.

- Statements of qualifications, work experiences and past projects for each of the Subcontractor's staff likely to be assigned to this subcontract as well as examples of work product, and their expected contribution to the deliverables, and Subcontract amounts.

- Subcontractor's staff likely to be assigned to this Subcontract as well as examples of work product, and their expected contribution to the deliverables, and Subcontract amounts.

- If the Subcontractor procures the services of any party outside of the Subcontractor's organization, that procurement must be explained in detail to the services to be procured, the reason for the outside procurement and the rest of the information sought in the other bullets in this section.

- Identification of primary contact and their contact information.

1. Subcontractor(s) Selection Proposal

NARUC will select a Subcontractor(s) (s) through a competitive selection.

2. Budget Estimate

Subcontractor(s) must identify the total costs and should provide a budget estimate of the cost-components expected for this analysis. Cost categories in this budget estimate should include labor, travel, and other direct costs (such as supplies, printing, other expenses.), and costs of sub-Subcontractor(s)s.

An example table that may be useful in responding to this RFP follows. Respondents may use any budget format they prefer (see on table on next page).

Subcontractor(s) Labor			
	Hours	**Rate**	
Name of Principal / Senior			

Name(s) of Junior Subcontractor(s) (other			
Total Labor Cost Estimate			$
Other Direct Costs (by task)			
Travel to EISPC Meetings*	(4 trips)	(cost)	$
Printing of Interim and Final Reports	(documents)	(cost)	$
Communications (such as conf. calls)			$
Other (identify other costs if necessary)			$
Total Other Direct Costs			$
Total			**$**

*** Up to four (4) EISPC Meetings from May 2013 – June 2014**

SCOPE OF WORK FOR STUDY

Proposal Format

The proposal should be submitted using the following format:

1. **Summary -** A discussion reflecting the applicant's understanding of the proposed deliverables.
2. **Products** - Products to be delivered, including detailed description and schedule.
3. **Experience -** Company information indicating level of experience in providing the subject data.
4. **Costs** – Time, materials and total estimated cost. The scope of the project is to be May 3, 2013 through June 30, 2014. Time, materials and other fees should be outlined in the Subcontractor's bid. Applicants(s) must also identify the total cost.
5. **Other Information -** Any other information which may assist in the review of a submitted proposal, such as brochures, literature, or data samples, may be submitted with, but shall not be considered part of the proposal.

Scope of Work

1) The Subcontractor shall work with the members of the collaborative process and others in the electric industry and the natural gas industry to understand and catalog short and long-term operational, contracting, and planning concerns. These shall help to ensure the electric and natural gas assumptions used in the natural gas / electric infrastructure analysis are consistent. For example, since electricity is traded on a an hourly basis in some areas and often on a 5 minute basis and natural gas transactions are less frequent, to what extent do these transactional differences affect the ability of gas and electricity to coordinate more effectively? How does the difference affect reliability of gas and electric supply? Historically, electric generators have often avoided paying for pipeline costs due, in large part, to their resource diversity and the relationship to the demand for gas. However, with

increased reliance on natural gas, this seems likely to change. How can electric utilities ensure a reliable supply of natural gas? The Subcontractor shall detail some methods for electric utilities paying for pipeline construction such as uplift charges.

2) Using either the three "Futures" and associated transmission system build-outs developed by the Eastern Interconnection analysis or mutually agreed upon alternatives that have a high, low, and middle case, the Subcontractor shall develop a 20 year analysis (2011-2030) of the electric infrastructure (including DR and EE) requirements for the Eastern Interconnection (unless the Scope is expanded to include other Interconnections). The study shall provide as much state-by-state detail as reasonably feasible.

3) Combine information from the natural gas industry on current and potential infrastructure in an effort to develop a coherent analysis of the potential electric and natural gas infrastructure requirements for the 2011-2030 time-frame if possible. Initially, the Subcontractor shall consider the work already done by the natural gas industry and, subject to the approval of the Collaborative Process, decide on the feasibility of using all or some portion as an overlay on the three Futures and transmission build-outs discussed in (1). Subsequent adjustments to the infrastructure requirements for both gas and electricity could then be made.

The Subcontractor shall detail all of the significant assumptions and data used in preparing the analysis. In this regard, the Subcontractor shall work with both the natural gas and electric industries to ensure that relevant assumptions are consistently applied to the analysis of both industries. The Subcontractor should consider the significant advantages of using analysis that has been, or is being, conducted for both the electric and natural gas industries. For the electric industry component of the study, the most important advantage of using the three Futures and the information from the three indicative transmission build-outs is that the assumptions used were fully vetted by a transparent stakeholder process after vigorous debate. These included fuel price forecasts, potential ramifications of environmental policies, load growth assumptions considering demand response and energy efficiency, and potential changes in generation technologies including renewable resources that significantly affect the delivered cost to customers. Similarly, the advantage of using recent natural gas industry analysis is that the assumptions were also detailed in a comprehensive manner. If the decision is made to develop alternative Futures, the data and assumptions must be vetted by those involved in the collaborative process which may be a very time consuming process.

4) After the assessment of data, assumptions, and analysis available from the natural gas and electric industries is carried out, the Subcontractor shall make a list of additional information that would be helpful in conducting the long-term assessment of natural gas and electric infrastructure requirements. The Subcontractor shall work with the respective industries, the FERC, NERC, and others to obtain the requisite information in a timely manner while being cognizant of proprietary and confidential information (including critical energy infrastructure information).

5) The Subcontractor, in consultation with the other participants in this collaborative effort, shall consider existing state-of-the-art planning tools available to the electric and natural gas industries. The Subcontractor shall assess these tools and make a recommendation to be approved by the Collaborative process. In considering planning tools, the Subcontractor shall evaluate the feasibility of using co-optimization techniques to develop a hypothetical optimal infrastructure requirement for natural gas and electricity over the twenty year horizon. If co-optimization is deemed to be currently infeasible, the Subcontractor is expected to recommend a second best approach, provide the rationale for using other planning tools, and utilize the tools to develop a well-reasoned assessment of long-term natural gas and electric infrastructure requirements in this hypothetical analysis. The Subcontractor is also expected to recommend the data and analytical techniques that would be required to better co-optimize electric and natural gas industry infrastructure.

6) In its analysis of the long-term natural gas and electric infrastructure requirements, the Subcontractor is expected to assess reliability metrics and issues for the natural gas and electric systems. This shall include the economic implications of the various Futures and associated infrastructure build-outs. In this regard, the Subcontractor should take into consideration the work done for NARUC / EISPC on the Economics of Resource Adequacy as well as other relevant work by or for the natural gas and electric industries such as FERC and NERC.

7) The Subcontractor is expected to document / catalog the on-going efforts by the natural gas and electric industries, DOE / National Laboratories, the Federal Energy Regulatory Commission, and others to assess natural gas and electric infrastructure requirements.

8) The Subcontractor is expected to detail significant operational and definitional differences that will have to be considered in this long-term natural gas and electric infrastructure analysis. This should include contracting changes to better assure that infrastructure is built in a timely and reliable manner. The Subcontractor is expected to detail potential critical energy infrastructure, anti-trust, and proprietary concerns that may limit efforts of the natural gas and electric industry to engage in long-term assessments – even hypothetical assessments.

9) The Subcontractor shall provide a discussion of the federal and state siting requirements, state and federal laws / regulations that affect (positively or negatively) new infrastructure requirements. The Subcontractor and the collaborative process may wish to consider proposals to expedite the construction of needed infrastructure. For example, could states play a more proactive role with intrastate pipelines? The Subcontractor should consider information including, but not limited to, reports prepared for the natural gas industry, the electric industry (including the National Electric Reliability Corporation), EISPC (e.g., Market Structures Report, Energy Zones, Demand Response, Energy Storage, Nuclear,

Coal, and the Economics of Resource Adequacy), Department of Energy and its National Laboratories, the Environmental Protection Agency, and the Federal Energy Regulatory Commission.

10) The Subcontractor shall provide an assessment of future analysis that would be beneficial to the United States, the natural gas industry, and the electric industry. In preparing the analysis, the Subcontractor should reference on-going work by NARUC / EISPC, DOE and its National Laboratories, FERC, NERC, NAESB, the Planning Coordinators, the Natural Gas industry, and others.

11) The Subcontractor is expected to provide a Final Report that will be understandable to a broad audience and be approved by NARUC / EISPC and the participants in the collaborative process. The Final Report shall include a glossary of terms, a bibliography, and appropriate maps and other graphics. Regarding the Energy Zones Mapping Tool developed by Argonne National Laboratories (which includes electric and natural gas infrastructure data in the Eastern Interconnection), within the first 30 days of the engagement, the Subcontractor shall contact Argonne to determine if there are opportunities for collaboration that are beneficial. This work may be mutually beneficial for both the Subcontractor as well as for Argonne's Energy Zones work. To the extent that it is beneficial to do so, the Subcontractor shall coordinate with Argonne National Laboratory's work on Energy Zones.

The Subcontractor is expected to provide participants in the collaborative effort with quarterly updates unless determined otherwise by NARUC /EISPC or participants in the collaborative process. These periodic updates may take the form of in-person meetings or webinars.

***While EISPC/NARUC believe the above scope of work may be deemed by the collaborative process to be sufficiently comprehensive, we recognize that modifications to this scope of work may be made as a result of the initial stakeholder meeting.**

BACKGROUND SECTION

Initial Milestones/Deliverables

Milestones

- Kick-off conference call/Initial stakeholder meeting
- Short monthly Progress Reports
- Up to four in-person meetings
- Up to six conference calls
- In-person meeting and webinar
- Draft Report to be provided by mid June 2013
- Final Report to be submitted to the full EISPC Council for approval.

Deliverables

Enhancements, if any, to the Scope of Work to be included in the monthly report and submitted to NARUC/EISPC for approval.

Kick-off conference call/Initial stakeholder meeting with EISPC and stakeholders to make any adjustments to the Scope of Work from the collaborative process. At the outset of this white paper and study, EISPC / NARUC believe it would be very helpful to have a meeting of Stakeholder Participants to sharpen the focus of the study and whitepaper to make sure that the most important aspects are addressed on a comprehensive basis. The Subcontractor may be asked to lead portions of the discussion.

Monthly Reports. Presented in written form and in person at EISPC meetings, as funding allows, and at the discretion of EISPC.

Up to four (4) in-person meetings with EISPC and stakeholders to discuss the conduct of the Study obtain input from the collaborative process.

Up to six (6) conference calls. Conference calls will be conducted as deemed to be appropriate by EISPC. The conference calls will include EISPC and / or participants in the collaborative effort and Subcontractors doing related work, as well as EISPC's counterparts in the Western Interconnection and ERCOT.

In-person meeting and webinar at an EISPC meeting, prior to completion of the Final Report, to present the draft report and obtain suggestions and comments.

Draft Final Report due by June 11th, 2014.

Final Report due by June 30, 2014.

Timeline

Responses to RFP due	April 6, 2013
Subcontractor(s) selected/Subcontract(s) executed	May 3, 2013
Kick-off conference call/Initial stakeholder meeting	May 13, 2013
Short monthly progress reports (via email with potential follow-up by phone)	Due at the beginning of each month throughout project duration
Up to four (4) in-person meetings	May 2013 – June 2014 (specific dates TBD)
In-person meeting and webinar	May 2014
Up to six (6) conference calls	May 2013 – June 2014 (specific dates TBD)
Draft Final Report	June 11, 2014
Final Report	June 30, 2014

Rejection of Proposals & Incurred Costs

NARUC reserves the right to reject any or all submitted proposals not in conformance with this RFP, or for other causes. NARUC shall not be liable for any costs incurred by any Subcontractor(s) prior to the execution of a Subcontract.

Questions and further information

All questions and information requests should be addressed to Miles Keogh, NARUC's Director of Grants & Research, by email at mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org.

REQUEST FOR PROPOSALS TO ADDRESS

Solicitation Number: NARUC-2013-RFP025-DE0316

A WHITE PAPER ON LONG-TERM NATURAL GAS AND ELECTRIC INFRASTRUCTURE REQUIREMENTS OF THE EASTERN INTERCONNECTION

Part 2: White Paper on Long-Term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection

F. Introduction

States are taking an increasingly active interest in the potential implications of increased utilization of natural gas for electric generation and the ramifications for more traditional natural gas usage; including the effects on natural gas distribution companies. From the perspective of EISPC, there seem to be several operational, contracting, planning, and regulatory differences (including the ability of natural gas and electric industry to engage in planning) that may frustrate improved operations and planning. Some of these may be definitional. Others may be attitudinal. Still others may be intrinsic.

G. Department of Energy Requirements

This white paper will be undertaken under Department of Energy agreement DE-OE-0000316, funded under the American Recovery and Reinvestment Act of 2009 (ARRA).

Respondents must be able to comply with the ARRA Award Terms and the core funding agreement with regards to transparency, reporting, financial management, and separate accountability for ARRA funding, lobbying exclusions, Davis-Bacon Act compliance and other areas. This RFP requires the subcontractor(s) to include on their SEFA information to specifically identify Recovery Act funding. This information is needed to allow the NARUC to properly monitor subcontractor(s) expenditure of ARRA funds as well as oversight by the Federal awarding agencies, Offices of Inspector General and the Government Accountability Office. NARUC will not enter into any contract or subcontract in connection with this Contract with a party that has been debarred or suspended from contracting with the Federal Government. Refer to Excluded Parties List System at https://www.epls.gov/. NARUC will require a certification indicating that the sub-recipient is not debarred or suspended from receiving federal funds and requiring notification to the NARUC if its status should change; https://www.bpn.gov/ccr/ – the sub-recipients is required to register in the CCR, including obtaining a Dun and Bradstreet Data Universal Numbering System (DUNS) number, and to keep the registration and number current.

Please be advised in order to comply with the lobbying restrictions of the core funding agreement from the Department of Energy no proposal may be intended to support lobbying efforts of any kind (including advocating specific outcomes of federal agency regulatory activities) or be proposed with any of the aforementioned activities in mind.

H. Period of Performance

The period of performance for this award will be from May 3, 2013 to (no later than) June 30, 2014; unless approved by NARUC/EISPC and DOE. It is anticipated that successful Subcontractor(s) will be notified by April 22, 2013.

I. Funds Budgeted

The budget for the White Paper on Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection shall not exceed $220,000 (two-hundred and twenty thousand dollars) unless otherwise approved by EISPC / NARUC, and the DOE. All bids shall contain a detailed budget estimate (please template in Section J).

J. Responding to the RFP

Please submit responses to the RFP no later than April 6, 2013 to Miles Keogh, NARUC's Director of Grants and Research, by email to mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org with the email subject:

White Paper on Long-Term Natural Gas and Electric Infrastructure Proposal

There is no specific limitation on page numbers or format, although brevity and completeness will aid the selection process. All questions regarding the RFP should be directed to Miles Keogh and Sharon Thomas by email as well. In responding to this RFP, the Subcontractor(s) must respond to the following sections:

- A detailed explanation of how the Subcontractor(s) will fulfill the requirements listed, by task, in the Scope of Work. For example, if research is required, what type of research methods would the Subcontractor(s) employ to complete the research?

- Detailed timelines / milestones with deliverables in order to fulfill the requirements listed, by task, in the Scope of Work.

- A detailed budget, similar to the format provided, that estimates the costs of fulfilling the terms of this Subcontract(s).

- A statement of qualifications, work experience and past projects by the Subcontractor(s) on topics similar to those in this RFP. Experience in multiple regions of the Eastern Interconnection should be highlighted.

- Statements of qualifications, work experiences and past projects for each of the Subcontractor's staff likely to be assigned to this subcontract as well as examples of work product, and their expected contribution to the deliverables, and Subcontract amounts.

- Subcontractor's staff likely to be assigned to this Subcontract as well as examples of work product, and their expected contribution to the deliverables, and Subcontract amounts.

- If the Subcontractor procures the services of any party outside of the Subcontractor's organization, that procurement must be explained in detail to the services to be procured, the reason for the outside procurement and the rest of the information sought in the other bullets in this section.

- Identification of primary contact and their contact information.

1. Subcontractor(s) Selection Proposal

NARUC will select a Subcontractor(s) through a competitive selection.

2. Budget Estimate

Subcontractor(s) must identify the total costs and should provide a budget estimate of the cost-components expected for this analysis. Cost categories in this budget estimate should include labor, travel, and other direct costs (such as supplies, printing, other expenses.), and costs of sub-Subcontractor(s)s.

An example table that may be useful in responding to this RFP follows. Respondents may use any budget format they prefer (see table on next page).

Subcontractor(s) Labor			
	Hours	**Rate**	
Name of Principal / Senior			
Name(s) of Junior Subcontractor(s) (other			
Total Labor Cost Estimate			$

Other Direct Costs (by task)			
Travel to EISPC Meetings*	(4 trips)	(cost)	$
Printing of Interim and Final Reports	(documents)	(cost)	$
Communications (such as conf. calls)			$
Other (identify other costs if necessary)			$
Total Other Direct Costs			$
Total			**$**

*** Up to four (4) EISPC Meetings from May 2013 – June 2014**

SCOPE OF WORK FOR WHITE PAPER

Proposal Format

The proposal should be submitted using the following format:

1. **Summary -** A discussion reflecting the applicant's understanding of the proposed deliverables.
2. **Products** - Products to be delivered, including detailed description and schedule.
3. **Experience -** Company information indicating level of experience in providing the subject data.
4. **Costs** – Time, materials and total estimated cost. The scope of the project is to be May 3, 2013 through June 30, 2014. Time, materials and other fees should be outlined in the Subcontractor's bid. Applicants(s) must also identify the total cost.
5. **Other Information -** Any other information which may assist in the review of a submitted proposal, such as brochures, literature, or data samples, may be submitted with, but shall not be considered part of the proposal.

Scope of Work

This white paper will be used by States, federal agencies, the electric industry, the natural gas industry and others, so it is imperative that the information be well-written, comprehensive, and useful for the variety of audiences. While the Stakeholder Meeting at the outset of this work will provide the final guidance to the Consultant(s), EISPC / NARUC, based on numerous meetings between the natural gas and electric industries, believe the following topics are likely to be included in the final list:

1. Different market structures for both the electric system (such as RTOs and non-market regions) and each of the elements of the natural gas system;

2. System operations for both electricity and natural gas. This should include: the timely sharing of information to address the needs of both the natural gas and electric industries; the electric industry's intra-hour (as low as 5 minute intervals) compared to the intra-day nomination processes used by the natural gas industry; and contracting issues due to the different schedules, load shapes and load duration curves for both the natural gas and electric industry with a discussion of the implications of the industry load characteristics;

3. Electric issues such as
    a. The ability to better integrate intermittent resources using natural gas facilities;
    b. The potential for substantial increases in natural gas-fired generation due to such things as rigorous carbon regulation and the attendant effect on the Nation's coal fleet;
    c. The potential implications for electric industry reliability of an expanded dependency on natural gas;

4. Contracting procedures and issues. The Subcontractor shall provide a discussion of: (i) typical contract process that reflects the operational requirements of both the natural gas and the electric industry; (ii) typical terms and conditions for electric generators purchasing natural gas (the commodity, pipeline, storage); (iii) potential changes being considered by the natural gas industry in their contracting procedures to better accommodate the range of operating requirements of electric generators; (iv) Potential changes being considered by the electric industry in their contracting procedures to better accommodate the natural gas industry's operating requirements; (v) the Subcontractor shall provide an independent assessment of what changes in the natural gas and electric contracting process, terms, and conditions that might better accommodate both the natural gas and electric operational requirements; (vi) address if there is a role for Regional Transmission Organizations / ISOs to facilitate contracting and construction of required facilities; (vii) address if there is a constructive role for states to facilitate contracting and construction of required facilities?

5. Planning issues including the limitations imposed on electric transmission and resource planning. This should include the FERC's , NERC's, and, where applicable, the Market Monitor's perspectives;

6. Planning issues among the gas industry elements including producers, pipelines, storage, and local distribution companies.

7. Planning issues between the natural gas and electric industries;

8. The implications for planning due to the various regulatory regimes and the issues that result from those differences;

9. A discussion of the most often used planning tools available to the natural gas and electric industries;

10. Issues regarding the capability to integrate the natural gas and electric planning tools;

11. Immediate and longer-term data limitations and concerns that may limit natural gas and electric planning. By way of examples, are there load forecasting issues that need to be addressed? Are there equipment availability / capability concerns that are important for improved planning in both the natural gas and electric industries?;

12. Confidentiality and critical infrastructure concerns and potential solutions to overcome those concerns to allow the natural gas and electric industries, states, and others to engage in operational and long-term planning;

13. Federal and state regulatory issues for the natural gas and electric industries, and recommendations to overcome any perceived obstacles. What, if any, actions can states take to facilitate the timely construction of new natural gas infrastructure?;

14. Potential payment options for improvements to the natural gas infrastructure to increase the deliverability and efficiency of natural gas to meet the needs of the electric industry;

15. Recommendations on future actions to improve natural gas and electric industry coordination;

16. Glossary of terms, bibliography, and a discussion of contracting concepts.

Initial Milestones/Deliverables

Milestones

- Kick-off conference call/Initial stakeholder meeting
- Short monthly Progress Reports
- Up to four in-person meetings with stakeholders/participants, as directed by EISPC
- Conference calls as needed, with EISPC, stakeholder, and subcontractors doing related work
- Draft Report to be provided for review by EISPC
- Final Report to be submitted to the full EISPC Council for approval.

Deliverables

Enhancements, if any, to the Scope of Work to be included in the monthly report and submitted to NARUC/EISPC for approval.

Kick-off conference call/Initial stakeholder meeting with EISPC and stakeholders to make any adjustments to the Scope of Work from the collaborative process. The Subcontractor may be asked to lead the discussion. At the outset of this white paper and study, EISPC / NARUC believe it would be very helpful to have a meeting of Stakeholder Participants to sharpen the focus of the study and whitepaper to make sure that the most important aspects are addressed on a comprehensive basis. The Subcontractor may be asked to lead portions of the discussion.

Monthly Reports. Presented in written form and in person at EISPC meetings, as funding allows, and at the discretion of EISPC.

Coordination. EISPC / NARUC wish to build on the work of NAESB, FERC, NERC, the natural gas industry, and the Electric Industry for this white paper. Participation by the National Laboratories is also being requested. To this end, we have invited these organizations to participate in the process. EISPC / NARUC believe that a broad collaborative is the best approach despite being difficult to administer. The Subcontractor is expected to work with EISPC to coordinate the participation by the various stakeholders.

Draft Final Report due by June 2, 2014. This draft will invite comments from participants in the collaborative effort but, ultimately, is subject to the approval by NARUC / EISPC.

Final Report due by June 30, 2014. This final report will ultimately be subject to the approval by NARUC / EISPC.

Timeline

Responses to RFP due	April 6, 2013
Subcontractor(s) selected/Subcontract(s) executed	May 3, 2013
Kick-off conference call/Initial stakeholder meeting	May 13, 2013
Short monthly progress reports (via email with potential follow-up by phone)	Due at the beginning of each month throughout project duration
Up to four (4) in-person meetings with stakeholders / participants, as directed by EISPC	May 2013 – June 2014 (specific dates TBD)
Conference calls as needed with EISPC, stakeholders and subcontractors doing related work	May 2013 – June 2014 (specific dates TBD)
Draft Final Report	June 2, 2014
Final Report	June 30, 2014

Rejection of Proposals & Incurred Costs

NARUC reserves the right to reject any or all submitted proposals not in conformance with this RFP, or for other causes. NARUC shall not be liable for any costs incurred by any Subcontractor(s) prior to the execution of a Subcontract.

Questions and further information

All questions and information requests should be addressed to Miles Keogh, NARUC's Director of Grants & Research, by email at mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org.

N A R U C
National Association of Regulatory Utility Commissioners

EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

STUDY: Request for proposals to assist the Eastern Interconnection States' Planning Council (EISPC) members with the preparation of one to four studies on Probabilistic Risk Assessment for Transmission and Other Resource Planning

Solicitation Number: NARUC-2013-RFP026-DE0316

WHITE PAPER: Request for proposals to assist the Eastern Interconnection States' Planning Council (EISPC) members with the preparation of a white paper on the Incorporation of Risk Analysis into Planning Processes

Solicitation Number: NARUC-2013-RFP027-DE0316

****PROPOSALS MAY BE SUBMITTED FOR EITHER THE STUDY OR THE WHITE PAPER, OR BOTH****

RELEASED: March 8, 2013

RESPONSES DUE FOR STUDY: MARCH 29, 2013

RESPONSES DUE FOR WHITE PAPER: MARCH 29, 2013

Grants & Research Department
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue NW, Suite 200
Washington, D.C. 20005

REQUEST FOR PROPOSALS TO ADDRESS

Solicitation Number: NARUC-2013-RFP026-DE0316

ONE TO FOUR STUDIES ON PROBABILISTIC RISK ASSESSMENT FOR TRANSMISSION AND OTHER RESOURCE PLANNING

Part 1: One to Four Studies on Probabilistic Risk Assessment for Transmission and Other Resource Planning

A. Introduction

The electric industry in the United States is experiencing rapid institutional evolution and change that has important ramifications for the cost of providing reliable electric service. Introduction of wholesale competition, FERC orders for open access to the transmission system and transparent transmission planning (and on a regional basis), formation of Regional Transmission Organizations, and establishment of mandatory and enforceable transmission planning standards have all affected both the planning process and operation of the power system. To keep pace with these changes, institutions with responsibility for implementation of these policies should examine whether the tools used to develop and assess transmission and other resource plans continue to serve adequately or whether additional analytical techniques are feasible or available to complement and where appropriate replace existing practice.

Traditional transmission planning methods are typically deterministic with the use of ad-hoc approaches to address uncertainty. These methods have served the industry relatively well in the past. Fundamental changes in the use of transmission over vast distances to address not only reliability concerns but also longer-term economic interests, together with the increasing cost of those facilities, uncertainties concerning the location of new resources and retirement of older generators, increasingly stringent environmental regulations requiring changes to the resource mix, the need to integrate large amounts of variable energy resources, more dynamic electric loads, and the lead times to construct major facilities, have together led to significantly more complex and less predictable use of transmission facilities and have raised the question of whether existing planning methods are adequate. EISPC proposes to study a new framework for transmission planning with explicit consideration of uncertainties.

NARUC / EISPC is issuing this Request for Proposal as part of a concerted effort to better understand the role of "risk" in all aspects of utility planning, with particular emphasis on transmission planning. This analysis, with its focus on the incorporation of risk analysis in transmission planning, is not intended as a comprehensive replacement of the existing deterministic methods used by the industry. Rather, the analysis may provide an important additional tool to assess the value of transmission and other resources and to do so in a more integrated manner.

This proposed work relates to other on-going EISPC/ NARUC studies. Of particular relevance here are two interrelated RFPs that have already been issued. These involve the Economics of Resource

Adequacy and Co-Optimization of Transmission with other Electric Resources[1]. While this RFP primarily seeks a Study of Risk Assessment as it affects transmission planning, we are asking Subcontractors for this RFP to provide a cursory assessment of the potential for the use of Probabilistic Risk Assessment (PRA) for planning other resources. EISPC is also seeking (separately from the PRA study) a white paper primer to offer guidance to States and others on how to incorporate risk analysis into the planning of transmission and other resources (see part 2 later in the RFP).

Part 1 includes case studies, built upon data gathered either in ongoing or recently concluded transmission planning exercises, or in the EIPC / EISPC Eastern Interconnection study. The Subcontractor(s) is to provide their recommended approach to address the issues articulated in the scope of work, and is further invited to recommend and justify enhancements or modifications to the scope of work. It is EISPC's / NARUC's intent to invite Planning Coordinators[2] to work with states in their region to participate in the case studies to assess the ramifications of using Probabilistic Risk Assessment in evaluating transmission options and transmission with other resources. To assist prospective Subcontractor(s) in structuring their bids we recommend providing a detailed discussion of the cost associated with various activities and levels of effort discussed in this RFP or proposed by the Subcontractor(s).

Regarding the study and by way of examples regarding the level of activity beyond the core information required: 1) a Subcontractor might wish to bid on a single case study or multiple case studies; 2) should bidder be unable to conduct an analysis based on actual data from a planning authority, EISPC/NARUC will consider a study using information from the transmission build-out analysis just completed by EIPC in December 2013 (see phase II Report on EIPConline.com). Whether a case study(ies) or information from the Transmission build-outs are used, the Subcontractor will be asked to conduct a webinar for the benefit of all EISPC States (and other interested parties). The Subcontractor will also be asked to coordinate their work with the related RFPs mentioned previously, and the National Laboratories. EISPC has invited the North American Electric Reliability Corporation to serve in an advisory role.

B. Grant Requirements

This study will be undertaken under Department of Energy agreement DE-OE-0000316, funded under the American Recovery and Reinvestment Act of 2009 (ARRA).

Respondents must be able to comply with the ARRA Award Terms and the core funding agreement with regards to transparency, reporting, financial management, and separate accountability for ARRA funding, lobbying exclusions, Davis-Bacon Act compliance and other areas. This RFP requires the subcontractor(s) to include on their SEFA information to specifically identify Recovery Act funding. This information is needed to allow the NARUC to properly monitor subcontractor(s) expenditure of ARRA funds as well as oversight by the Federal awarding agencies, Offices of Inspector General and the Government Accountability

[1] In addition, to work on co-optimization of transmission with other electric resources and the economics of resource adequacy, a current listing of other Studies and Whitepapers that, to varying extents, address risk in planning transmission, nuclear and coal generation, demand response, energy efficiency, energy storage, customer-owned generation can be found using the following link: http://communities.nrri.org/web/eispc/share-and-view-files-members/-/document_library/view/349934

[2] Planning Coordinators may also be referred to as Planning Authorities.

Office. NARUC will not enter into any contract or subcontract in connection with this Contract with a party that has been debarred or suspended from contracting with the Federal Government. Refer to Excluded Parties List System at https://www.epls.gov/. NARUC will require a certification indicating that the sub-recipient is not debarred or suspended from receiving federal funds and requiring notification to the NARUC if its status should change; https://www.bpn.gov/ccr/ – the sub-recipients is required to register in the CCR, including obtaining a Dun and Bradstreet Data Universal Numbering System (DUNS) number, and to keep the registration and number current.

Please be advised in order to comply with the lobbying restrictions of the core funding agreement from the Department of Energy no proposal may be intended to support lobbying efforts of any kind (including advocating specific outcomes of federal agency regulatory activities) or be proposed with any of the aforementioned activities in mind.

C. Period of Performance

The period of performance for this award will be from **April 25, 2013 to (no later than) June 30, 2014**; unless approved by NARUC/EISPC and DOE. It is anticipated that successful Subcontractor(s) will be notified by the end of April 15, 2013.

D. Funds Budgeted for Study/Studies

A total of up to $700,000 (seven hundred thousand dollars) has been budgeted for the entire study portion of the project, depending on the number of studies that will be provided (between one to four studies). We estimate that for a single case study, the cost will be $250,000, and additional studies will be $150,000. However, NARUC/EISPC reserves the right to alter this amount depending on the responses and to ensure that other EISPC priorities are satisfied.

All bids shall contain a detailed budget estimate (please see illustrative template in section E) that reflects the development of the Report including: the conduct of 1 to 4 Case Studies and / or the use of information from the Interconnection planning analysis. The cost of each Case Study should be specified. This should include meetings, webinars, and calls to enlist Planning Coordinators and utilities in collaborative Case Studies;

E. Responding to the RFP

Please submit responses no later than March 29, 2013 to the RFP to Miles Keogh, NARUC's Director of Grants and Research, by email to mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org with the email subject:

"Probabilistic Risk Assessment Study(ies) Proposal" and/or

"Probabilistic Risk Assessment White Paper Proposal"

There is no specific limitation on page numbers or format, although brevity and completeness will aid the selection process. All questions regarding the RFP should be directed to Miles Keogh and Sharon Thomas by email as well.

1. Subcontractor(s) Selection Proposal

NARUC will select a Subcontractor(s) (s) through a competitive selection.

2. Budget Estimate

Subcontractor(s) must identify the total costs and should provide a budget estimate of the cost-components expected for this analysis. Cost categories in this budget estimate should include labor, travel, and other direct costs (such as supplies, printing, other expenses.), and costs of sub-Subcontractor(s)s.

An example table that may be useful in responding to this RFP follows.

Subcontractor(s) Labor			
	Hours	**Rate**	
Name of Principal / Senior			
Name(s) of Junior Subcontractor(s) (other			
Total Labor Cost Estimate			**$**
Other Direct Costs (by task)			
Travel to EISPC Meetings*	**(1 trip)**	**(cost)**	**$**
Printing of Interim and Final Reports	**(documents)**	**(cost)**	**$**
Communications (such as conf. calls)			**$**
Other (identify other costs if necessary)			**$**
Total Other Direct Costs			**$**
Total			**$**

*** One (1) EISPC Meetings in May 2013**

Proposal Format

The proposal should be submitted using the following format:

1. **Summary -** A discussion reflecting the applicant's understanding of the proposed deliverables.
2. **Products** - Products to be delivered, including detailed description and schedule.
3. **Experience -** Company information indicating level of experience in providing the subject data.
4. **Costs** – Time, materials and total estimated cost. The scope of the project is to be April 25, 2013 to no later than June 30, 2014. Time, materials and other fees should be outlined in the Subcontractor's bid. Applicants(s) must also identify the total cost.
5. **Other Information -** Any other information which may assist in the review of a submitted proposal, such as brochures, literature, or data samples, may be submitted with, but shall not be considered part of the proposal. Identification of primary contact and their contact information.

SCOPE OF WORK FOR STUDY/STUDIES

The Subcontractor is expected to:

- Be familiar with the literature regarding Probabilistic Risk Assessment for transmission planning;
- Have familiarity with on-going work regarding risk assessment being conducted by the North American Electric Reliability Corporation and Planning Coordinators/utilities;
- Incorporate and share relevant analysis done for EISPC from other studies and white papers;
- Recommend actions that might be taken by states to improve the quality and quantity of information for conducting well-reasoned risk analysis for transmission and other utility planning;
- Provide recommendations for future work including studies, databases, analysis, equipment, etc. by Planning Coordinators and others to enhance the efficacy of risk assessment in resource planning;
- Coordinate with the North American Electric Reliability Corporation, the Federal Energy Regulatory Commission, and the National Laboratories. In large part, this is required to better ensure there is no undue duplication of effort;
- Coordinate analysis with and, if possible, collaborate on studies with the Eastern Interconnection Planning Collaborative (EIPC). This shall include, but not be limited to, case studies and /or building on the transmission analysis and the three transmission build-outs. In discussing collaboration, the Subcontractor shall be EISPC's agent to assist EISPC in negotiating the scope of work for a case study(ies);
- Incorporate studies and analysis conducted by EISPC/EIPC and its counterparts in the Western Interconnection and the Electric Reliability Council of Texas (ERCOT). If possible collaborate on future studies and analysis with EISPC's / EIPC's counterparts in the Western Interconnection and ERCOT;
- Present analysis in written form, in-person, by webinar, and by conference call to EISPC and others as deemed to be appropriate by EISPC.

The Subcontractor is expected to provide the following:

1. Case Study(ies):
    A. The most important deliverable is a case study(ies)[3] to provide quantitative and qualitative information about the use of Probabilistic Risk Assessment in transmission analysis as a means of evaluating nearer-term reliability projects and longer-term economic / reliability projects by using PRA in comparison to traditional methods. The case study(ies) shall be performed with states in collaboration with a Planning Coordinator(s), individual utilities, or by building on the information contained in the Interconnection analysis (see eipconline.com for Phase 1 and II information). The approach must be approved by EISPC. EISPC recognizes the need for negotiating a Scope of Work that satisfies the mutual needs of EISPC members and the Planning Coordinator /utility.

        - The Subcontractor shall prepare a detailed proposal discussing its approach to the case study(ies). This should detail the resources and data the Subcontractor intends to use. The Subcontractor's detailed proposal concerning case studies shall include conducting at least one and as many as four case studies involving the collaboration of a Planning Coordinator or utility and state commissions.
        - As an alternative approach, use the information from Phase 1 and II of the transmission analysis that was completed in December 2012 by the Eastern Interconnection Planning Collaborative (EIPC – eipconline.com) if we are unable to conduct a collaborative study with one or more Planning Coordinators / utilities;
        - A description of how the Subcontractor will examine the potential value offered by probabilistic assessment of transmission plans in comparison to a conventional deterministic needs assessment by applying probabilistic techniques to the same data set.

2. The Subcontractor must describe their plan to develop a qualitative assessment of whether and how the use of a probabilistic study complements or should replace the use of a deterministic study in areas including:
    A. To what extent, if any, does PRA have the potential to improve the transparency of the planning process;
    B. What information and analytical techniques are needed and desirable for conducting PRA? To what extent do other EISPC / NARUC studies facilitate PRA;
    C. To what extent is the treatment of stochastic input variables such as load growth, fuel cost, climate events, variable generation, generation expansion/retirement, demand response, energy efficiency, energy storage, and customer-owned generation affected by PRA;
    D. Incorporation of new transmission technologies into PRA;
    E. The comparison of alternative transmission and non-transmission solutions and whether decision making on treatment of identified needs is facilitated or complicated by the probabilistic analysis and if so, how;

[3] This RFP only contemplates work done for the Eastern Interconnection. If, however, collaborative arrangements can be made with EISPC's counterparts in the Western Interconnection and / or ERCOT, the Scope of Work may be expanded. If there is an expansion of the Scope of Work involving EISPC's counterparts in the Western Interconnection and/or ERCOT, EISPC understands additional remuneration may be required.

F. Whether the information provided through the probabilistic assessment is adequate to understand the cost effectiveness of various solution alternatives examined;
G. The ability to allow diversified contingencies (weather effects, cascading outages, catastrophic events);
H. Optimizing operation reserve requirements, especially with regard to variable energy resources;
I. Whether PRA affords an opportunity to increase acceptance by regulatory bodies, stakeholders, and others;
J. Other areas identified by the Subcontractor where such an assessment would be relevant for future investigation.
K. Background information on the current and potential use of PRA in transmission planning. This should include a discussion of current methods and the potential advantages / disadvantages of PRA in comparison to current deterministic methods.

3. Final Report:
   A. Include a glossary of terms; the definition of terms and concepts should include examples where appropriate.
   B. Include a bibliography that includes relevant studies, papers, applicable software, and NERC analysis.

BACKGROUND SECTION

Initial Milestones/Deliverables

Milestones

- Kickoff Conference Call
- Short monthly Progress Reports
- In-person attendance at three (3) EISPC meetings
- Draft Report
- Final Report

Deliverables

The Subcontractor shall provide a study(ies) that includes the scope of work mutually agreed upon by NARUC and the subcontractor. That is, the subcontractor, subject to the approval of NARUC, may offer embellishments to improve the quality and usefulness of the study.

Enhancements, if any, to the Scope of Work to be included in the monthly report and submitted to NARUC/EISPC for approval.

Kick-off Conference Call to discuss the Subcontractor's initial approach with the Studies and White Paper Work Group

Monthly Reports are to be submitted at the beginning of each month.

Three in-person meetings.

Meeting 1: in-person and will include a webinar at an EISPC meeting, as deemed appropriate by EISPC to discuss the initial approach.
Meeting 2: in-person meeting and webinar at an EISPC meeting mid-way through the project.
Meeting 3: in-person meeting and webinar at an EISPC meeting, prior to completion of the final report, to present the draft report and obtain feedback.

Participation in up to six (6) conference calls throughout the project. At the discretion of EISPC, these will be with the Studies and White Paper Work Group, other subcontractors doing related work, EISPC, as well as EISPC's counterparts in the Western Interconnection and ERCOT

Draft research approach, if applicable, presented to EISPC for review and comment.

Draft Initial Report presented to EISPC for review and comment. Presented in written form and in person at EISPC meetings, as funding allows, and at the discretion of NARUC/EISPC.

Final Report. Submitted in written form.

Timeline

Responses to RFP due	March 29, 2013
Subcontractor(s) selected/Subcontract(s) executed	April 25, 2013
Kick-off conference call	Week of April 29 – May 3, 2013
Conference Calls (up to 6) throughout remainder of project	May 2013 – June 30, 2014 (specific dates TBD)
Short monthly progress reports (via email with potential follow-up by phone)	At the beginning of each month throughout period of performance
In-person meeting #1 and webinar at an EISPC meeting	May 30-31, 2013
In-person meeting #2 and webinar at an EISPC meeting	June 2013 – June 30, 2014 (specific date TBD)
In-person meeting #3 and webinar at an EISPC meeting	June 2013 – June 30, 2014 (specific date TBD)
Draft report	June 2, 2014
Final report	June 30, 2014

Rejection of Proposals & Incurred Costs

NARUC reserves the right to reject any or all submitted proposals not in conformance with this RFP, or for other causes. NARUC shall not be liable for any costs incurred by any Subcontractor(s) prior to the execution of a Subcontract.

Questions and further information

All questions and information requests should be addressed to Miles Keogh, NARUC's Director of Grants & Research, by email at mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org.

REQUEST FOR PROPOSALS TO ADDRESS

Solicitation Number: NARUC-2013-RFP027-DE0316

A WHITE PAPER ON THE INCORPORATION OF RISK ANALYSIS INTO PLANNING PROCESSES

Part 2: White Paper on the Incorporation of Risk Analysis into Planning Processes

F. Introduction

EISPC is also seeking (separately from the probabilistic risk assessment study) a white paper primer to offer guidance to States and others on how to incorporate risk analysis into the planning of transmission and other resources. In general terms, the white paper is intended to serve as a primer on the use of Probabilistic Risk Assessment for transmission planning and other electric resources to help states better understand the risks of uncertainties.

G. Department of Energy Requirements

This white paper will be undertaken under Department of Energy agreement DE-OE-0000316, funded under the American Recovery and Reinvestment Act of 2009 (ARRA).

Respondents must be able to comply with the ARRA Award Terms and the core funding agreement with regards to transparency, reporting, financial management, and separate accountability for ARRA funding, lobbying exclusions, Davis-Bacon Act compliance and other areas. This RFP requires the subcontractor(s) to include on their SEFA information to specifically identify Recovery Act funding. This information is needed to allow the NARUC to properly monitor subcontractor(s) expenditure of ARRA funds as well as oversight by the Federal awarding agencies, Offices of Inspector General and the Government Accountability Office. NARUC will not enter into any contract or subcontract in connection with this Contract with a party that has been debarred or suspended from contracting with the Federal Government. Refer to Excluded Parties List System at https://www.epls.gov/. NARUC will require a certification indicating that the sub-recipient is not debarred or suspended from receiving federal funds and requiring notification to the NARUC if its status should change; https://www.bpn.gov/ccr/ – the sub-recipients is required to register in the CCR, including obtaining a Dun and Bradstreet Data Universal Numbering System (DUNS) number, and to keep the registration and number current.

Please be advised in order to comply with the lobbying restrictions of the core funding agreement from the Department of Energy no proposal may be intended to support lobbying efforts of any kind (including advocating specific outcomes of federal agency regulatory activities) or be proposed with any of the aforementioned activities in mind.

H. Period of Performance

The period of performance for this award will be from April 25, 2013 to (no later than) June 30, 2014; unless approved by NARUC/EISPC and DOE. It is anticipated that successful Subcontractor(s) will be notified by April 15, 2013.

I. Funds Budgeted

The budget for the white paper on the Incorporation of Risk Analysis into Planning Processes shall not exceed $250,000 (two-hundred and fifty thousand dollars) unless otherwise approved by EISPC / NARUC, and the DOE. All bids shall contain a detailed budget estimate (please template in Section J).

J. Responding to the RFP

Please submit responses to the RFP no later than March 29, 2013 to Miles Keogh, NARUC's Director of Grants and Research, by email to mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org with the email subject:

White Paper on the Incorporation of Risk Analysis into Planning Processes

There is no specific limitation on page numbers or format, although brevity and completeness will aid the selection process. All questions regarding the RFP should be directed to Miles Keogh and Sharon Thomas by email as well. In responding to this RFP, the Subcontractor(s) must respond to the following sections:

- A detailed explanation of how the Subcontractor(s) will fulfill the requirements listed, by task, in the Scope of Work. For example, if research is required, what type of research methods would the Subcontractor(s) employ to complete the research?

- Detailed timelines / milestones with deliverables in order to fulfill the requirements listed, by task, in the Scope of Work.

- A detailed budget, similar to the format provided, that estimates the costs of fulfilling the terms of this Subcontract(s).

- A statement of qualifications, work experience and past projects by the Subcontractor(s) on topics similar to those in this RFP. Experience in multiple regions of the Eastern Interconnection should be highlighted.

- Statements of qualifications, work experiences and past projects for each of the Subcontractor's staff likely to be assigned to this subcontract as well as examples of work product, and their expected contribution to the deliverables, and Subcontract amounts.

- Subcontractor's staff likely to be assigned to this Subcontract as well as examples of work product, and their expected contribution to the deliverables, and Subcontract amounts.

- If the Subcontractor procures the services of any party outside of the Subcontractor's organization, that procurement must be explained in detail to the services to be procured, the reason for the outside procurement and the rest of the information sought in the other bullets in this section.

- Identification of primary contact and their contact information.

1. Subcontractor(s) Selection Proposal

NARUC will select a Subcontractor(s) through a competitive selection.

2. Budget Estimate

Subcontractor(s) must identify the total costs and should provide a budget estimate of the cost-components expected for this analysis. Cost categories in this budget estimate should include labor, travel, and other direct costs (such as supplies, printing, other expenses.), and costs of sub-Subcontractor(s).

An example table that may be useful in responding to this RFP follows. Respondents may use any budget format they prefer.

Subcontractor(s) Labor			
	Hours	**Rate**	
Name of Principal / Senior			
Name(s) of Junior Subcontractor(s) (other			
Total Labor Cost Estimate			$
Other Direct Costs (by task)			
Travel to EISPC Meetings*	(4 trips)	(cost)	$
Printing of Interim and Final Reports	(documents)	(cost)	$
Communications (such as conf. calls)			$
Other (identify other costs if necessary)			$
Total Other Direct Costs			$
Total			**$**

*** Up to four (4) EISPC Meetings from May 2013 – June 2014**

SCOPE OF WORK FOR WHITE PAPER

Proposal Format

The proposal should be submitted using the following format:

1. **Summary -** A discussion reflecting the applicant's understanding of the proposed deliverables.
2. **Products** - Products to be delivered, including detailed description and schedule.
3. **Experience -** Company information indicating level of experience in providing the subject data.
4. **Costs** – Time, materials and total estimated cost. The scope of the project is to be April 25, 2013 to no later than June 30, 2014. Time, materials and other fees should be outlined in the Subcontractor's bid. Applicants(s) must also identify the total cost.
5. **Other Information -** Any other information which may assist in the review of a submitted proposal, such as brochures, literature, or data samples, may be submitted with, but shall not be considered part of the proposal.

Scope of Work

While the genesis of this RFP was to assess the potential for developing a formalized process for evaluating, on an integrated basis, transmission plans with other resource plans, states are routinely confronted with a variety of planning risks / questions including, but not limited to:

- What analytical techniques can be used to help planners evaluate the results of two or more alternative plans?
- How should the performance risks of demand response be assessed?
- How should the risks of under (or over) forecasting demand be assessed to limit the attendant costs of uncertainty? After establishing the assumptions and data for a "high" and "low" case, is it necessarily appropriate to think of a middle case as being the "most probable" or "business as usual?" This should apply not only to forecasting but to other elements of the planning process where there are important risks that need to be considered.
- What are appropriate techniques for assessing the contribution of intermittent resources to serve the peak demand or any other specific period?
- How should the cost of fuels or capital costs be evaluated for risk to help policymakers better assess competing policy options?
- How is the planning risk for a specific utility affected by the plans of neighboring systems; often with different assumptions and purposes?

- How do the algorithms of various models affect risk assessments (e.g., the use of load duration curves versus hourly (or more discrete) information)?
- What are examples of how the quality and quantity of data affect risk analysis?
- What useful financial analyses (details, appropriate uses, limitations, examples) are used in assessing risks of various resource plans?

To help states and others address a broad range of often complex planning issues on a more systematic basis, the Subcontractor should provide a primer that offers guidance concerning:

1. Basic statistical concepts – including probability analysis. This should provide EISPC members with a discussion of the costs of uncertainty, the ability of probabilistic planning to address the cost of uncertainty, and the sources of uncertainty that states/regions may (and have been) confronted with;

2. Application of statistical concepts to planning problems using a variety of case studies as examples tailored to the needs of states within each region[4]. The Subcontractor shall offer up to four case studies for approval by EISPC / NARUC for the Eastern Interconnection. At least one case study should include assessing transmission options with various competing resource options (e.g., generation, DR). This should also include uncertainties related to load forecasting, fuel cost analysis, capital cost analysis, and ramifications for resource adequacy;

3. Background of probabilistic planning
   a) Theoretical underpinnings and benefits compared to deterministic approaches
   b) Basic methodologies for use in transmission planning
   c) Data to conduct the analysis (both the requisite and desirable) and analytical requirements
   d) Economic quantification of outage/unavailability costs
   e) Summary of ISO/RTOs experiences and salient characteristics where probabilistic approach is used
   f) Track record: notable successes and failures of probabilistic approach, particularly in comparison with deterministic approaches.

4. Institutional requirements for conducting PRA. The white paper shall discuss the institutional challenges faced by transmission planning organizations should they determine to add a probabilistic planning component to current practices. Items which should specifically be discussed include what would be needed to facilitate and possibly improve

[4] EXAMPLE OF REGIONALLY SPECIFIC ANALYSIS: New England states asked for a comparison of ISO-NE's deterministic planning process with an existing ISO/RTO where probabilistic planning is used (e.g., British Columbia Hydro). The comparison should be based on the review of comparable project types. The comparison should include elements in this RFP and address: planning criteria and objectives, data requirements and sources, software tools, analytics, assumptions and subjective assessments made, staffing and consulting assistance needs- both initial and ongoing, review costs and timeframe, stakeholder review and vetting process, regulatory review and approval, economic efficiency, consideration of environmental factors, implied level of "acceptable" risk of outages, and quantification of outage-related costs.

the PRA analysis, for example software requirements, data requirements and sources, human resource considerations (e.g., expertise), current and emerging regulatory perspectives of federal and state commissions.

5. A general discussion of how states participating in the case study(ies) currently conduct transmission and other resource planning, how they participate (or expect to participate) in transmission planning processes. This shall also provide information on how these states incorporate risk analysis in all aspects of resource planning for other resources (e.g., IRP, or working with RTOs and other Planning Coordinators). States will be asked to provide the information and the Subcontractor shall, where necessary, follow up with tailored questions for participating states. The Subcontractor shall format the information in a manner that is approved by EISPC;

6. Jurisdictional Issues: Transmission owners and RTOs face multiple jurisdictional authorities in the development of transmission plans and construction of transmission facilities. They are required to meet NERC mandatory reliability requirements, various FERC Orders requiring Open Access, transparent planning (including interregional planning), due consideration of non-transmission alternatives, and consideration of public policy projects, compliance with state siting review requirements is necessary in most states. The Subcontractor is requested to comment on how a probabilistic approach can address these mandates, if at all.

7. Recommendations on how states/regions might effectively use risk assessment in their planning processes or their evaluation of the planning processes of their utilities / Planning Coordinators;

8. Definition of terms and concepts with examples;

9. Bibliography of empirical studies, papers, analytical / software tools that would facilitate states' use of PRA and risk analysis more generally in planning applications, training programs that states may wish to consider.;

In preparing this white paper, the Subcontractor is expected to incorporate relevant work from other EISPC Studies and Whitepapers (including information from the PRA Study as it becomes available), related work from the National Laboratories, NERC, and others.

Initial Milestones/Deliverables

Milestones

- Kick-off conference call/Initial stakeholder meeting
- Short monthly Progress Reports
- Up to two (2) conference calls / webinars with the relevant states as deemed to be appropriate by those states.

- Up to three (3) coordination calls with EISPC's Studies and White Paper Group
- At EISPC's discretion, up to two (2) webinars for state / regional training
- Up to three (3) in-person meetings with EISPC, at the discretion of EISPC
- Draft Report to be provided for review by EISPC
- Final Report to be submitted to the full EISPC Council for approval.

Deliverables

Enhancements, if any, to the Scope of Work to be included in the monthly report and submitted to NARUC/EISPC for approval.

Kick-off conference call/Initial stakeholder meeting with EISPC and stakeholders to make any adjustments to the Scope of Work from the collaborative process.

Monthly Reports. Presented in written form and in person at EISPC meetings, as funding allows, and at the discretion of EISPC.

Up to 2 conference calls / webinars with the relevant states as deemed to be appropriate by those states.

Coordination Calls. Up to three coordination calls with EISPC's Studies and White Paper Group to: (i) discuss the initial approach; (ii) provide a mid-term report to better ensure the Subcontractor's work is responsive to EISPC's needs; (iii) a discussion of the final draft report

At EISPC's discretion, up to two (2) webinars for state / regional training

Up to three in-person meetings with EISPC, at the discretion of EISPC to: (a) discuss the initial approach; (b) obtain input and suggestions following the release of the draft final report; and (c) a discussion of the final report and a discussion of the state educational effort.

Draft Final Report due by June 15, 2014. This draft will invite comments from participants in the collaborative effort but, ultimately, is subject to the approval by NARUC / EISPC.

Final Report due by June 30, 2014. This final report will ultimately be subject to the approval by NARUC / EISPC.

Timeline

Responses to RFP due	March 29, 2013
Subcontractor(s) selected/Subcontract(s) executed	April 25, 2013
Kick-off conference call/Initial stakeholder meeting	Week of April 29 – May 3, 2013
Short monthly progress reports (via email with potential follow-up by phone)	Due at the beginning of each month throughout project duration
Up to two (2) conference calls/webinars	June 2013 – June 2014 (specific dates

	TBD)
Up to three (3) coordination calls	June 2013 – June 2014 (specific dates TBD)
In-person attendance at EISPC meeting	May 30-31, 2013
In-person attendance at EISPC meeting	June 2013 – June 2014 (specific dates TBD)
In-person attendance at EISPC meeting	June 2013 – June 2014 (specific dates TBD)
Draft final report	June 2, 2014
Final report	June 30, 2014

Rejection of Proposals & Incurred Costs

NARUC reserves the right to reject any or all submitted proposals not in conformance with this RFP, or for other causes. NARUC shall not be liable for any costs incurred by any Subcontractor(s) prior to the execution of a Subcontract.

Questions and further information

All questions and information requests should be addressed to Miles Keogh, NARUC's Director of Grants & Research, by email at mkeogh@naruc.org, Sharon Thomas at sthomas@naruc.org and Bob Pauley at Bob.Pauley@eispc.org.

EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

The Economic Ramifications of Resource Adequacy White Paper

January 2013

Astrape Consulting
For EISPC and NARUC
Funded by the U.S. Department of Energy

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The information and studies discussed in this report are intended to provide general information to policy-makers and stakeholders but are not a specific plan of action and are not intended to be used in any State electric facility approval or planning processes. The work of the Eastern Interconnection States’ Planning Council or the Stakeholder Steering Committee does not bind any State agency or Regulator in any State proceeding.

EXECUTIVE SUMMARY

Resource adequacy is of critical importance to utilities, consumers, and regulators. The financial impact of shedding firm load or having scarcity events in the electric energy market can be measured in billions of dollars as evidenced by the California Energy Crisis in the early 2000's and more recently during the extreme weather in Texas in the summer of 2011. These events illustrate that the value provided by electric service far exceeds the physical costs of producing the electricity. Surveys of electric service outage costs indicate that the Value of Lost Load (VOLL) can be $15,000/MWh[1] or greater while the production cost of a marginal unit can be only $50/MWh – a factor of 300x. This comparison, however, ignores a critical component of the economics of resource adequacy – the carrying costs of having excess capacity available during those peak hours. Assuming the carrying cost of new capacity is $100,000/MW-yr and VOLL is $15,000/MWh, the capacity must be used to prevent firm load shed more than 6 hours per year to be economically justified. However, in most regions, marginal capacity is needed to prevent firm load shed much less frequently. The resource adequacy standard many regions plan to is a Loss of Load Expectation (LOLE) of one firm load shed event in 10 years (herein referred to as 1-in-10 LOLE), suggesting the last resource added to the system is only needed approximately 0.3 hours per year[2]. At this frequency of utilization, VOLL would have to be an unrealistic $300,000/MWh to justify the last resource addition. For a point of reference, $300,000/MWh VOLL is comparable to $900 for keeping the power on in a normal sized house for one hour[3]. This review suggests that if marginal capacity's only benefit was avoiding firm load shed events, it is unlikely economics would justify maintaining a system as reliable as we have today. The example above illustrated the economics for only shedding firm load due to generation deficiency once every 10 years. However, actual resource adequacy is typically even higher than that. While distribution related outages occur several hours per year for most customers[4], most regions in the Eastern Interconnection have not experienced generation deficiency caused firm load shed events in decades.

But is resource adequacy solely about having enough capacity to meet firm load obligations? Or are there other benefits of reserves that should be considered when setting target Reserve Margins[5]? When load is high and supplies are scarce, market prices can far exceed the production cost of an efficient Combustion Turbine (CT). How much of these costs should be avoided by building additional capacity? There are also other substantive benefits of having robust levels of reserves such as avoiding the dispatch of high cost units or energy limited resources. Economic resource adequacy assessments should take a

---

[1] Estimates of VOLL vary widely. The range of estimates and their impact on resource adequacy planning are discussed in Section IV.

[2] A typical firm load shed event has a 3 hour duration. One event in 10 years equals 3 hours in 10 years or 0.3 hours per year.

[3] An average house uses 3kW on peak. Three kWh divided by 1000 kW/MW times $300,000/MWh = $900.

[4] Newell, Sam, "ERCOT Investment Incentives and Resource Adequacy", Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

[5] In this paper, Reserve Margin is calculated by: (Total Capacity Resources – Expected Annual Peak Load) / Expected Annual Peak Load. Conventional resources and demand side programs are counted at full nameplate or designated capacity. Demand side resources are accounted for in projecting the Expected Annual Peak Load. Only a portion of intermittent resource nameplate capacity is counted as a capacity resource.

comprehensive approach to calculating the trade-off between the cost of additional capacity and the economic benefit provided by those resources. This white paper attempts to quantify this trade-off for a defined base case and a number of sensitivities. The point at which the cost of further resource additions is equal to the economic benefit provided by such additions is herein referred to as the economic reserve margin or economically optimal reserve margin or risk neutral economic reserve margin.

For the case study included in this paper, the economic optimal reserve margin is based on minimizing total systems costs from the perspective of the customers of a vertically integrated utility. These costs include all production costs of the utility plus net imports from outside regions plus the societal costs of firm load shed events. In this setup, during reliability events, only incremental purchases are assigned high costs since all load served by the utility's resources is priced at its respective production cost. In these hours, customers continue to receive the benefit of low cost, base load units such as coal and nuclear. The total customer costs then are a combination of low cost energy from existing resources plus incremental energy purchases from the market at higher costs during capacity shortfalls. Also, in this type of environment, a utility pays for incremental capacity costs which are included as part of total system costs. However, in structured markets, the cost of energy is the same for all load since energy is priced based on the marginal resource. If the market price of energy is $800/MWh, then all load must pay this price. However, the mechanism under which energy costs are ultimately passed on to customers can be quite different from region to region depending on market structure and whether or not a load serving entity self supplies a large portion of its load. Also, capacity costs are frequently handled differently. The question of economic reliability is fundamentally different in these markets and is addressed separately in this paper.

The following key conclusions were made based on the resource adequacy assessment research and simulated case study:

- Reviews of various resource adequacy assessments in the Eastern Interconnection indicate wide variations in the way capacity is counted, what level of benefit will be received from emergency operating procedures, and what assumptions and tools are used. Even though many regions use 1-in-10 LOLE or a similar metric, these variations make the comparison of reliability difficult.
- Most prior studies that evaluated the economics of resource adequacy indicated low optimal economic reserve margins. The authors believe this is primarily because only a subset of all customer benefits of the marginal capacity was captured.
- When considering all benefits (production cost savings, import cost savings during shortages, and the societal cost of Expected Unserved Energy (EUE)) of marginal capacity from the perspective of a customer of a single vertically integrated utility, the economic reserve margin is greater than that indicated by 1-in-10 LOLE for many regions. However, system size, resource mix, load shape, market availability and other factors can affect the optimum economic reserve margin and make it either higher or lower than the 1-in-10 LOLE based reserve margin.
- If economic targets were based solely on societal costs (production costs plus the cost of EUE) and ignored scarcity pricing that result in transfers of wealth to outside regions or generators, the economic target would decrease by several percentage points. However, the authors do not believe this setup is realistic or desirable.
- Risk analysis shows that a range of reserve margins slightly above the economic optimal reserve margin can avoid a number of potentially high cost scenarios for little additional cost.

- Modeling assumptions for neighboring regions such as weather diversity and import capability have a significant impact on both the 1-in-10 LOLE and economic optimal reserve margin
- Because unserved energy is de minimus at a 1-in-10 LOLE based reserve margin, the Value of Lost Load has little impact on the economic analysis. Instead it is driven by the dispatch of high cost resources and scarcity pricing events which occur much more frequently than loss of load events.
- Not all capacity resources provide the same value. Most resource planners recognize that wind and solar may provide little load carrying capability relative to their nameplate capacity. However, in addition to those resources, demand response, energy storage, and hydro also have very different load carrying capability as well as economic capacity value, and their respective value should be taken into account.
- Resource adequacy targets should evolve to properly balance the costs and benefits of reliability if the 1-in-10 LOLE based reserve margin level is not justified.
- Merchant generators in energy only markets will likely not recover their fixed costs at a 1-in-10 LOLE based reserve margin or an economic optimal reserve margin based on the perspective of customers in a regulated utility environment.
- Because all generators are paid the same price under current forward capacity market constructs, the total costs to consumers to maintain a 1-in-10 based reserve margin that is above the energy only market economic target will always be higher, however, there is some risk benefit seen by customers due to the reduction of high cost outcomes.

Future Analysis

While this white paper provides a number of informative conclusions to assist regulators in reviewing the reasonableness of resource adequacy plans, many questions remain outstanding that were beyond the scope of the original effort. This paper was not designed to identify the most appropriate economic reserve margins for particular regions, utilities, ISOs and RTOs, but the case studies indicate they could be different from current targets by 5% or more. If current reserve margin targets are 5% too high or 5% too low, the economic inefficiency for individual regions could be in the hundreds of millions of dollars per year. Further, case studies indicated that changing penetrations of demand response and intermittent resources can affect resource adequacy planning, but the way that the impact of these resources should be addressed is highly specific to individual markets. Also, how should economic resource adequacy be addressed by states in structured markets?

The results of this white paper should not be construed to suggest that resource adequacy planning is already approximately optimal in the Eastern Interconnection. There are significant opportunities for resource adequacy planning to produce substantial economic benefits for consumers. Additional analysis could provide key insights into how this could be accomplished.

- Potential Tasks:
    - Assess the economic efficiency of the reliability standards of particular regions, utilities, ISOs and RTOs in the Eastern Interconnect. To perform this assessment, the following steps would need to be performed:
        - Build load, resource, and transmission data for the remainder of the regions in the Eastern Interconnection
        - Refine unit availability data and transmission availability data for the regions already modeled.

        - Perform simulations for the entire Eastern Interconnection and determine one economic optimal reserve margin assuming coordinated planning across the entire Interconnect.
        - Provide comparisons of economically derived reserve margins to current resource adequacy plans.
        - Provide additional sensitivities around key assumptions such as scarcity pricing, economic load forecast uncertainty, and demand response constraints.
        - Analyze different market structures and rules to understand the impact. Use economic reliability simulations to estimate demand curves for capacity markets.
    - Demand response programs play a significant and expanding role in addressing resource adequacy. As the penetration of demand response increases, the flexibility and availability required of these resources will also rise. The treatment of these programs in various market structures must also be considered as their value profile can be very different from traditional resources and can change vastly from program to program. Several sensitivities were performed to quantify some of these considerations, but additional work is warranted. The additional work would primarily examine different types of demand response programs with different characteristics. These include reliability only, economic, and real time pricing programs. Optimal demand response portfolios could also be developed.
    - Resource adequacy is not just a concern during the peak hours of the year. Changing resource mixes will require different types of assessments to address flexibility requirements for many hours of the year due to wind and other intermittent resources. While the cost of intermittent resource integration has been addressed in a number of studies, the impact of intermittent resources on operational resource adequacy has not received as much focus. An additional assessment that captures the flexibility of existing resources, the variability of loads, and the variability of intermittent resources on time intervals from minutes to days could be performed with the Strategic Energy and Risk Valuation Model (SERVM) used for this white paper. In addition to providing an assessment of potential challenges including the frequency, magnitude, and financial impact of reliability problems due to intermittency, several alternative solutions could be modeled to identify the most reliable and cost effective approaches to mitigating these events.
    - The work performed in this study could be leveraged to assess the reliability impact of certain transmission components probabilistically. Pairing SERVM with a transmission model such as EPRI's TransCARE would allow for the assessment of combined generation and transmission reliability. SERVM would be used to develop scenarios of load, weather, and unit commitment and feed subsets of those scenarios to the transmission module to understand the impact of probabilistic operation and failure of specific transmission components.

I. HISTORY OF RESOURCE ADEQUACY AND HOW TARGETS SHOULD EVOLVE

Resource Adequacy is a measure of an electric system's ability to provide adequate generation to meet all firm load obligations. If firm load obligations exceed the instantaneous generating capacity of a system, some firm load customers will have their access to electricity cut. This is a firm load shed event. Outages of firm load due to non-generation equipment failures and storms are not considered resource adequacy issues. Typical metrics of resource adequacy include Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), Loss of Load Events (LOLE), and Expected Unserved Energy (EUE). LOLH is a count of the number of hours in a year expected to have firm load shed. LOLP is the ratio of hours or days expected to have any firm load shed to the total hours or days in a year and is expressed as a percentage. LOLE is typically measured as a count of the expected number of days with at least one hour of lost load. EUE is the sum of all the expected firm load energy shed measured in MWh. It is the only one of these metrics that considers the magnitude of the outage. (Section II expands on these definitions, interpretations, and implementations of traditional reliability metrics)

Most electrical systems in North America have a resource adequacy target based on a defined physical reliability metric. While informal reliability targets have likely been utilized since electricity was first commercialized, the first mention of probabilistic resource adequacy assessments using specific physical reliability metrics identified in our research was in technical papers from the 30's and 40's. Giuseppe Calabrese' 1947 paper 'Generating Reserve Capacity Determined by the Probability Method' references setting reliability targets based on an expected number of days of loss of load over a given number of years[6]. C.W. Watchorn wrote several papers which discuss the development of appropriate system capacity reserves. In one such paper, Watchorn states "It is believed that a reasonable level of service reliability...is a probability of failure to carry the load of in the order of an average rate of one day in from eight to ten years".[7] However, the basis for that belief was not provided. Similar references to service reliability levels of 1 outage in every 10 years are made in dozens of technical papers from the 50's onward, although it is not clear from our review whether utilities or regions formalized resource adequacy targets around specific reliability metrics until several decades later. (See R. Billinton's bibliography of the history of resource adequacy assessments[8] for further references)

On November 9, 1965, a major electric power disruption in the Northeast US and Eastern Canada left 30 million people without power for over 12 hours. Although the cause of this event was primarily due to operator error, the event did occur during high load conditions.[9] In an effort to prevent the occurrence of similar events, electric utilities formed the North American Electric Reliability Council (NERC) in 1968. NERC reliability standards are focused on operating practices to ensure security ("the ability of the electric system to

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[6] Calabrese, Giuseppe, "Generating Reserve Capacity Determined by the Probability Method," American Institute of Electrical Engineers, Transactions of the IEEE, vol.66, no.1, pp.1439-1450, Jan. 1947

[7] Watchorn, C. W., "The Determination and Allocation of the Capacity Benefits Resulting from Interconnecting Two or More Generating Systems," American Institute of Electrical Engineers, Transactions of the IEEE , vol.69, no.2, pp.1180-1186, Jan. 1950

[8] Billinton, Roy, "Bibliography on the Application of Probability Methods in Power System Reliability Evaluation" IEEE Transmission Power Apparatus System, vol.91, no.2, pp.649-660, Mar/Apr 1972

[9] *Northeast Blackout of 1965.* Retrieved August 25, 2012, from http://en.wikipedia.org/wiki/Northeast_blackout_of_1965

withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[10]). However, the renewed focus on overall reliability also led to the development of specific resource adequacy targets. Mid Atlantic Area Council (MAAC) Reliability Principles and Standards set in place in 1968 state: "Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years."[11] Many other utilities and regions adopted similar standards.

How Should Resource Adequacy Targets Evolve?

One of the interesting aspects of reliability planning is that Resource Adequacy related outages represent a very small percentage of overall outages. As an example, the Brattle Group estimated that customers in Texas would average less than 1 minute per year of outages due to insufficient generation if the system was planned to maintain a 15% reserve margin.[12] This compares to an actual average of 100 - 300 minutes of outages per customer when all types of outages, including transmission and distribution outages, are considered.[13] Statistics are similar nationwide. A survey of utilities shows 107 minutes of outages per customer when all types of outages are considered.[14] Since resource adequacy events comprise only 1% or less of overall outages, why do they receive a high level of focus? Would a 1 in 5 or 1 in 2 LOLE be a reasonable level of physical reliability?

While 1-in-10 LOLE appears to be difficult to support from solely a physical reliability standpoint, several regions note other benefits of high levels of reliability. PJM states that "a well planned and adequate power system will lead to a secure system in day to day operations."[15] The California ISO suggests that high physical reliability supports the proper functioning of markets and that "market economics and reliability are inextricably intertwined." [16] There is little doubt that increased resource adequacy also plays a role in reducing high hourly market price scenarios. Many utilities mention additional unknowns beyond the factors considered in developing the 1-in-10 LOLE target such as fuel availability risk and environmental legislative risk that could force retirements of existing units. These points suggest there may be some margin of error embedded in the 1-in-10 LOLE target for some regions or utilities. In other words, unknown risks may push a system that is planned to

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[10] Glossary of Terms, prepared by the Glossary of terms Task force(GOTTF) North American Electric Reliability Council, GOTTF formed jointly by the NERC Engineering Committee(EC) and Operating Committee(OC), August 1996, www.nerc.com/glossary/glossary-body.html

[11] MAAC Reliability Principles and Standards, As adopted on July 18, 1968 by the Executive Board constituted under the MAAC Agreement, dated December 26, 1967 and revised March 30, 1990, Document A-1.

[12] Newell, Sam, "ERCOT Investment Incentives and Resource Adequacy", Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

[13] Ibid.

[14] LaCommare, Kristina, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers", September 2004, Ernest Orlando Lawrence Berkeley National Laboratory, Retrieved August 25, 2012 from http://certs.lbl.gov/pdf/55718.pdf

[15] PJM Generation Adequacy Analysis, October 2003, PJM Interconnection L.L.C., Retrieved August 25, 2012 from http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/20040621-white-paper-sections12.ashx

[16] Business Practice Manual for Reliability Requirements, August 9, 2012, California ISO, Retrieved August 25, 2012 from https://bpm.caiso.com/bpm/bpm/doc/000000000001253

a 1-in-10 LOLE target to have reliability that is somewhat lower in actual practice. Beyond the benefits of high levels of reliability afforded by the 1 in 10 standard, resource planners may also have additional motivations for continuing to use the standard. The 1-in-10 LOLE target is simple to calculate and explain and it has substantial precedent.

However, in relation to other cost/benefit analysis performed in the electric power industry, resource adequacy based on the 1-in-10 LOLE standard appears disproportionate. For example, in ERCOT, avoiding a hypothetical addition of 3,250 MW of new combustion turbines (a capital cost savings of more than $1.5B) would only increase customer's average resource adequacy outages from 0.1 minutes per year to 2.8 minutes per year.[17] When compared with 100 - 300 minutes of distribution related outages per customer, the hypothetical combustion turbines do not appear to provide an economically justifiable reliability benefit. Later sections of this white paper quantify some of these other benefits of high reliability mentioned as qualitative motivations supporting the 1-in-10 LOLE standard. Further, with the changing generation resource mixes that include intermittent generation such as wind and solar and a greater penetration of demand response resources, economically optimal reserve margins may vary further from a 1-in-10 LOLE standard than seen in prior studies. Our conclusions in this paper suggest that resource adequacy targets should evolve to properly balance the costs and benefits of reliability if the 1-in-10 LOLE level is not justified.

[17]Newell, Sam, "ERCOT Investment Incentives and Resource Adequacy", July 2012, The Brattle Group, Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

II. 1 DAY IN 10 YEAR STANDARD

A. TERMINOLOGY

- Loss of Load Expectation (LOLE): Expected number of firm load shed events an electric system expects in a given year
- Loss of Load Probability (LOLP): probability of firm load shed events typically expressed as a % of total hours in a year
- Loss of Load hours (LOLH): Expected number of hours of firm load shed events an system expects in a given year
- 1-in-10 LOLE Standard: Most commonly calculated as 1 event in 10 years and equals 0.1 LOLE per year
- Reserve Margin: (Resources – Peak Firm Demand) / Peak Firm Demand
- Capacity Margin: (Resources – Peak Firm Demand) / Resources

Not all regions and planners use the same definitions for all of these terms. Some refer to LOLP as the probability of having one or more hours of loss of load in any year. Others refer to LOLE as an hourly metric.

B. SURVEY SUMMARY

The results of our survey show that most regions use a similar standard for setting or measuring generation adequacy. Under this standard, adequate reliability is defined as the level of reserves that provide an expectation of less than one event in 10 years due to generation deficiency. While there are a few regions or utilities that use different standards, this standard has been in place for several decades for many of the members of the Eastern Interconnection. Details around the approach used in each area including references are provided in the following sections.

Table 1. Survey Summary

NERC Assessment Area	Reliability Criterion
FRCC	Reserve Margin criteria of 15% as a Regional Reserve Margin (20% for Investor Owned Utilities (IOU) and 15% - 18% for other utilities); Loss of Load Probability (LOLP) criteria of 1 day in 10 years or 0.1 LOLP[18])
SERC	SERC does not have a mandatory reserve margin or resource adequacy requirement for its members; Example Approaches: SOCO/TVA: base target reserve margins on minimizing total customer costs including societal

[18] Based on Astrape's understanding of the FRCC documentation, LOLP of 0.1 is consistent with the traditional 1 event in 10 years since LOLP is being calculated in days per year. FRCC has substituted the term LOLP for LOLE.

	costs of unserved energy; Progress Energy Carolinas: base target on 1-in-10 LOLE and minimizing total customer costs similar to SOCO/TVA.
SPP	Capacity Margin Criterion of 12% for RTO members that are steam based and 9% for hydro based; Capacity margins must meet 1 day in 10 years defined as an LOLE of 2.4 hours per year.[19]
PJM	1-in-10 LOLE (0.1 LOLE)
MISO	1-in-10 LOLE (0.1 LOLE)
NPCC - NY-ISO	1-in-10 LOLE (0.1 LOLE)
NPCC - ISO-NE	1-in-10 LOLE (0.1 LOLE)
NPCC - Maritimes	Reserve Margin criterion of 20% and an 1-in-10 LOLE (0.1 LOLE)
NPCC - Quebec	1-in-10 LOLE (0.1 LOLE)
NPCC - IESO	1-in-10 LOLE (0.1 LOLE)
Saskatchewan	Standard is based on an undisclosed level of Expected Unserved Energy (MWh)
Manitoba	Both an energy criterion and a reserve margin criterion due to the fact that the region is predominantly hydro. The energy criterion requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The reserve margin is at least 12%.
MAPP	1-in-10 LOLE (0.1 LOLE); Some of MAPP's members self impose a planning reserve margin of 15% based on the LOLE study performed in 2009.

[19] SPP uses the term LOLE of 2.4 hours which is more traditionally defined as an LOLH of 2.4 hours.

ERCOT	Although ERCOT performs a resource adequacy assessment to determine a target reserve margin necessary to meet 1-in-10 LOLE, there is not a mandatory requirement for the region. ERCOT operates as an energy only market and therefore does not have mandatory capacity requirements.
WECC	In general, each balancing area has responsibility for meeting resource adequacy standards established by respective states in which they operate.

Making the determination of what level of reserves yields 1-in-10 LOLE is a complex task and requires the development of a number of assumptions. There is little consistency in this process from region to region. Recent changes to resource mixes including higher penetrations of wind, solar, and demand response (DR) resources have contributed to even greater disparity between regions. A recent initiative by NERC resulted in a recommended list of modeling assumptions which will help to reconcile some of the disparity[20].

In addition to the disparity of assumptions used in assessing 1-in-10 LOLE, the reporting of the reserve margin that meets 1-in-10 LOLE is not standardized. The primary differences in reserve margin reporting include:

1. The method of capacity accounting. Some regions count all nameplate capacity for all resources. Other regions only count dependable capacity, frequently described as economic load carrying capability (ELCC) of a resource. This is a particular concern for wind, solar, hydro, energy storage, and any other constrained resource. In addition, some regions count expected imports as a capacity resource where others recognize the imports in modeling but do not count those imports as resources in the reserve margin calculation.
2. Emergency operating procedure accounting. Some regions include emergency operating procedures such as voltage control as capacity resources.

The following table attempts to demonstrate the impact of both modeling assumption differences and reserve margin reporting differences for a subset of the regions reviewed in this report to give the reader an appreciation for the different assumptions across regions. Note that some differences are appropriate due to physical differences in either resources or load profiles. The following table does not attempt to differentiate between legitimate and illegitimate assumption differences.

[20] *GTRPMTF Final Report*, Retrieved August 25, 2012, from http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf

Table 2: Reserve Margins and Impact on Reserve Margin of Various Assumptions

	PJM	NYISO	NE-ISO	Southern Company	SPP
Reliability Criteria	0.1 LOLE	0.1 LOLE	0.1 LOLE	Economics	2.4 LOLH
Reserve Margin at Reliability Standard	15.30%	16.10%	11.7%	15.00%	10.20%
Study Input Assumptions (Note: these components are not additive.)					
Treatment of Non-Firm Imports (What percentage of capacity resources are from non-contracted external generation)	0.00%	0.00%	2.10%	0.00%	0.00%
Weather Uncertainty (How much higher than normal can load be in extreme cases?)	8.00%	7.30%	10.10%	7.00%	5.30%
Equivalent Forced Outage Rate (Expected percentage of capacity offline during peak conditions)	7.30%	6.80%	4.90%	1.80%	5.90%
Economic Load Growth Uncertainty (How much faster than expected can load grow due to economic conditions?)	1.00%	1.00%	0.00%	2.20%	0.00%
External Assistance Benefit (What percentage of load can be reliably served by external regions)	1.90%	8.60%	5.50%	3.00%	0.00%

ELCC Impact of Wind (Some regions derate their reserve margin to account for variability of wind. For regions that do not, how much would their reported reserve margin drop if they only counted the effective load carrying capability of wind in their reserve margin?)	0.00%	4.70%	0.00%	0.00%	0.00%
ELCC Impact of Demand Response (For regions that discount Demand Response capacity to reflect contract limitations, how much higher would reserve margins be if they counted the full contract capacity?)	0.00%	0.20%	0.00%	1.10%	0.00%
ELCC Impact of Hydro (How much higher would reserve margins be if a region counted full nameplate for all hydro resources?)	0.00%	1.30%	0.00%	0.00%	0.00%
Operating Reserve Procedure Impact (Some regions assume operating reserves would be eliminated before firm load would be shed. Compared to a conservative approach of always maintaining full operating reserves, how much additional capacity do these regions assume?)	1.20%	5.50%	2.10%	0.00%	0.00%
Voltage Reduction Counting (Some regions count voltage reduction as a resource when calculating reserve margin. Other regions do not count voltage reduction as a resource even though they have voltage reduction programs. Compared to the approach of counting voltage reduction as a resource, how does a region's assumption affect their reserve margin?)	2.00%	1.50%	1.50%	0.00%	0.00%

Voltage Reduction Modeling (Some regions do not assume in their modeling that voltage reduction will be used to avoid firm load shed even if it would be called in actual practice. Compared to the standard approach of modeling the expected voltage reduction, how does a region's assumption affect their reserve margin?)	2.00%	0.00%	0.00%	0.00%	0.00%

Table 2 illustrates that a number of reporting and modeling assumptions can have a substantial impact on the reported reserve margin. For instance, in New York, the nameplate capacity of wind is counted in the reserve margin calculation. However, in PJM, the reserve margin calculation only includes the effective capacity of wind. Both regions' studies recognize that wind does not contribute much to reliability, but the accounting difference makes for an unwieldy comparison. If the NYISO accounting treatment was similar to PJM, NYISO's reserve margin would be 11.4% instead of 16.1%. The other items listed in Table 2 further illustrate how difficult it is to compare reserve margins across regions.

Aspects of some regions' modeling approaches seem conservative in some areas or aggressive in other areas. After attempting to normalize for most significant variables, regions may have 1-in-10 LOLE based reserve margins that vary by nearly 10%. Much of this difference is likely due to actual differences in resource mixes, transmission interconnections, and load profiles. However, these factors contribute to making it difficult for Commissioners and other regulators to assess the reasonableness of current resource adequacy planning. Our conclusion is that because of these issues, resource adequacy plans cannot be taken at face value even if all regions plan to a consistent 1-in-10 LOLE standard. If one is interested in comparing resource adequacy from region to region, then it is vital to understand the details surrounding the input assumptions to be able to identify whether a study's results are realistic and can be compared appropriately to studies performed by other entities. The comparisons performed here do not result in an assessment of the reasonableness of any entity's resource adequacy assessment, but rather simply point out the significant differences between studies. As discussed in the future analysis section of this paper, additional work could be performed to assess the reasonableness of each entity's resource adequacy plan.

C. Detailed Regional Review

The following sections outline the resource adequacy metric that is used for each NERC Long Term Assessment Area and how it is defined. The sections also contain useful information on how the metric is applied and other key factors impacting resource adequacy decisions.

1. Region Definitions

For this analysis, we will use the NERC Long Term Assessment Areas because resource adequacy criteria and decisions are more often made at this level rather than the other groupings.

Figure 1. NERC Long Term Assessment Areas

2. Eastern Interconnection

- **<u>Florida Reliability Coordinating Council (FRCC)</u>**

  Reliability Criterion: Reserve Margin criteria of 15% as a Regional Reserve Margin (20% for Investor Owned Utilities (IOU) and 15% - 18% for other utilities); Loss of load Probability (LOLP) criteria of 1 day in 10 years or 0.1 LOLP.

  Based on the FRCC 2012 Load & Resource Reliability Assessment Report,

  "The FRCC has a resource criterion of a 15% minimum Regional Reserve based on firm load. FRCC Reserve Margin calculations include merchant plant capacity that is under firm contract to load-serving entities. The FRCC assesses the upcoming ten-year summer and winter peak hours on an annual basis to ensure that the Regional Reserve Margin requirement is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum Reserve Margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC. Other utilities employ a 15% to 18% minimum Reserve Margin planning criterion."[21]

[21] *FRCC 2012 Load and Resource Reliability Assessment*, retrieved on September 1, 2012 from https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Reliability%20Assessments/FRCC%202012%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20RE%20PC%20Approved%20071012.pdf

The FRCC performed a Loss of Load Probability (LOLP) study in 2009 to verify that the reserve margin criteria were sufficient to meet a maximum LOLP of 0.1 day in a given year. The usage of the term LOLP is different from the traditional definition because it is measured in days per year similar to LOLE. Based on our review, this LOLP of 0.1 in consistent with the traditional 1 event in 10 years. Based on the report, FRCC is also exploring the possibility of a "generation only" reserve margin requirement since demand response penetration is projected to be quite high. Having substantial conventional resources may be important in systems with high penetration of demand response resources due to the voluntary aspect of demand response resources.

FRCC used the TIGER Model to perform its most recent LOLP studies.

- **Southeast Reliability Corporation (SERC)**

  SERC does not have a mandatory reserve margin or resource adequacy requirement for all of its members. Instead, resource adequacy targets are set by individual load serving members and may be subject to review by state regulators of individual members. With this approach, the final target reserve margins vary across the region. For this analysis, we focused on three of SERC's members (Southern Company, TVA, and Progress Energy Carolinas) which represent a portion of SERC-SE, SERC-N, and SERC-E. The information is based on recent IRP information.

  - **SERC-SE: Southern Company**

    Reliability Criterion: Target reserve margin is based on minimizing total system costs to customers.

    Southern Company published an "Economic Study of the System Planning Reserve Margin for the Southern Electric System"[22] in 2009. Based on this report, Southern Company selected a target reserve margin of 15% which approximately minimizes costs and reduces risks to customers.

    To perform this study, Southern used the SERVM model, a resource tool licensed by Astrape Consulting.

  - **SERC-N: TVA**

    Reliability Criterion: Planning reserve margin based on minimizing total system costs to the customer which results in a 15 percent reserve margin.

[22] *Southern Electric Reserve Economic Study of the System Planning Reserve Margin for the Southern Electric System* , retrieved on September 1, 2012 from http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=125981

Based on TVA's 2011 IRP, titled "Integrated Resource Plan, TVA's Environmental and Energy Future"[23]

"TVA identified a planning reserve margin based on minimizing overall cost of reliability to the customer. This reserve margin was based on a stochastic analysis that considered the uncertainty of unit availability, transmission capability, economic growth and weather to compute expected reliability costs. From this analysis a target reserve margin was selected such that the cost of additional reserves plus the cost of reliability events to the customer was minimized. This target or optimal reserve margin was adjusted based on TVA's risk tolerance in producing the reserve margin used for planning studies. Based on this methodology, TVA's current planning reserve margin is 15 percent and is applied during both the summer and winter seasons."

TVA used the SERVM Model to perform its analysis.

- **SERC-E: Progress Energy Carolina**

  Based on Progress Energy Carolina's 2012 IRP[24], Progress Energy uses a target reliability of one day in ten years LOLE for generation reliability assessments to set its minimum threshold. The company explains that a 14.5% reserve margin satisfies the one day in ten years LOLE criterion**,** but the company targets a range between 14.5% and 17% based on an economic analysis of total system costs to the customer.

  Progress Energy Carolinas used the SERVM Model to perform its analysis in 2012.

- **Southwest Power Pool (SPP)**

  Reliability Criterion: Capacity Margin criterion of 12% for RTO members that are steam based and 9% for hydro based; Capacity margins must meet 1 day in 10 Years defined as an LOLH of 2.4 hours per year.

  Based on SPP'S 2010 Loss of Load Expectation Report[25], the SPP capacity margin criteria requires each control area within SPP to maintain a 12% capacity margin for steam-based utilities and 9% for hydro based utilities. SPP calculates the LOLE of one day in ten years based on probabilistic modeling and the modeling results show that capacity margins could decrease to 9.6% and still meet this LOLE standard. Based on the study, however, SPP defines one day in ten years differently than the traditional definition. SPP assumes that an LOLH of 2.4 hours per year is 1 day in 10 years instead of one

[23] *Integrated Resource Plan TVA's Environmental & Energy Future*, retreived on September 1, 2012 from http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf

[24] *Progress Energy Carolinas Integrated Resource Plan 2012*, retrieved on Dec 1, 2012 from http://www.energy.sc.gov/publications/ProgressEnergyResource%20Plan2012.pdf

[25] *2010 Loss of Load Expectation Report* , retrieved on September 1, 2012 from http://www.spp.org/publications/LOLE%20Report_5%20Draft_cc.pdf

event (0.1 LOLE) in 10 years. The difference is significant because 2.4 hours per year is much less reliable than one event in 10 years.

SPP uses ABB Gridview to assess its reliability.

- **PJM**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Based on PJM's 2011 Reserve Requirement Study[26], the reserve margin requirement is 15.5% for the delivery period 2012/2013, 15.3% for the 2013/2014 delivery period, and 15.4% for the 2016/2017 delivery period. The reserve margin requirement supports a generation Loss of Load Expectation (LOLE) of one occurrence in ten years (LOLE = 0.1). PJM references RFC Standard BAL-502-RFC-01[27] as the reason the LOLE metric was adopted. The LOLE target reserve margin and various other calculations provide key inputs into the PJM Reliability Pricing Model (RPM). Through RPM, PJM ensures there are appropriate reserves to meet load. Individual Load Serving Entities (LSE) are not required to provide a specific reserve margin requirement and are allowed to make up shortfalls in the capacity markets. This aspect is much different than areas such as SERC, SPP, and FRCC where load serving entities are responsible for capacity procurement to meet the reliability criterion.

  PJM uses the PRISM model to perform its resource adequacy planning and also uses GE MARS for supplemental modeling.

- **MISO**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  According to MISO's 2012 Planning Year LOLE Study[28], MISO uses a minimum planning reserve margin of 16.7% across the entire MISO region and is based on meeting a 1-in-10 LOLE target (0.1 LOLE). It is the LSE's responsibility to meet the reserve margin target provided by MISO. The recently approved annual auction allows LSE's to purchase capacity to overcome deficiencies or opt to pay a penalty rather than purchase in the auction. Since the planning reserve margin of 16.7% provided by MISO is a regional reserve margin that doesn't account for load diversity among its members, the target for individual LSEs is 11.3% of its annual peak load. It should also be noted that State Commissions have the authority to set planning reserve margins for their state.

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[26] *2011 PJM Reserve Requirement Study*, retrieved on September 1, 2012, from http://www.pjm.com/~/media/committees-groups/subcommittees/raas/20110929/20110929-2011-pjm-reserve-requirement-study.ashx

[27] NERC Planning Resource Adequacy Analysis, retrieved on September 1, 2012, from http://www.nerc.com/files/BAL-502-RFC-02.pdf

[28] *Planning Year 2012 LOLE Study Report*, retrieved on September 2, 2012 from https://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf

MISO uses the GE MARS model to perform its resource adequacy analysis in combination with PROMOD to establish its zonal areas.

- **NPCC**

  All five regions within the NPCC region (NY-ISO, ISO-NE, Maritimes, Quebec, and IESO) require a reserve margin that at a minimum maintains an LOLE of 0.1 days per year. However, there are significant variations in how each area models the details of their system, surrounding regions, load, and other components. There are also differences in the application of the reserve requirements as NY-ISO and ISO-NE maintain resource adequacy through their structured capacity markets.

  - **NPCC-NYISO**

    Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

    Based on the Installed Capacity Requirements study performed by NYSRC in Dec. 2011[29], the required reserve margin to meet the 1-in-10 LOLE standard is 16.1% for the period of May 2012 to April 2013. This study is performed annually to set the annual statewide Installed Capacity Requirement (ICR) for the New York control area. Similar to PJM, these required reserve margin results are used in the NYISO's structured forward capacity markets.

    The LOLE analysis is performed using GE MARS.

  - **NPCC-ISO-NE**

    Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

    ISO-NE is the planning coordinator for the New England Area of the Northeast Power Coordinating Council (NPCC). Similar to PJM and NYISO, the reserve requirements serve as inputs to the structured Forward Capacity Market (FCM) which is used to procure the required amount of installed capacity resources to maintain system reliability. Based on the "New England 2011 Comprehensive Review of Resource Adequacy"[30], required resources are planned based on meeting the NPCC LOLE reliability criterion of no more than one day in ten years disconnection of non-interruptible customers.

    The LOLE analysis is performed using GE MARS.

[29] *New York Control Area Installed Capacity Requirements For the period May 2012 – April 2013,* retreived on September 2, 2012 from *http*://www.nysrc.org/pdf/Reports/2012%20IRM%20Final%20Report.pdf

[30] *New England 2011 Comprehensive Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/NE_2011_Comprehensive_Review_of_Resource_Adequacy%20-%20RCC%20Approval%20-%2020111129.pdf

- **NPCC-Maritimes**

  Reliability Criterion: Reserve Margin criterion of 20% and 1-in-10 LOLE (0.1 LOLE)

  Maritimes uses a 20% reserve margin criterion for planning purposes but at the same time adheres to the NPCC requirement of not shedding firm load more than 1 day in 10 years. Based on the 2011 Interim Resource Adequacy Review[31], the region meets both of these requirements for 2012 – 2015.

  The LOLE analysis is performed using GE MARS.

- **NPCC-Quebec**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Quebec adheres to the NPCC resource adequacy criterion. Based on an LOLE of 0.1, Quebec requires a 10% reserve margin for the 2012/2013 winter peak. By the 2015/2016 winter peak, Quebec requires a 12.2% reserve margin[32]. Because of its dependence on hydro generation to meet peak load, Quebec has also developed an energy criterion stating that sufficient resources should be available to go through a sequence of 2 consecutive years of low water inflows.

  The LOLE analysis is performed using GE MARS.

- **NPCC-IESO (Ontario)**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Based on the Ontario Reserve Margin Requirements Report[33], IESO bases its reserve margin requirement on an LOLE of 0.1 days per year. The target for 2013 to meet the one day in 10 year target is 19.7% which the region meets easily with an anticipated reserve margin of 40.1%.

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[31] *2011 Maritimes Area Interim Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%202011%20Maritimes%20Area%20Interim%20Resource%20Adequacy%20Review%20for%20TFCP.pdf

[32] *2011 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/Qu%C3%A9bec%20Comprehensive%20Review%202011.pdf

[33] *Ontario Reserve Margin Requirements*, retrieved on September 2, 2012 from http://www.ieso.ca/imoweb/pubs/marketReports/Ontario-Reserve-Margin-Requirements-2012-2016.pdf

- **Sask Power**

  Reliability Criterion: Based on an unspecified expected unserved energy (EUE) criteria.[34]

  Per NERC's 2011 Long Term Resource Assessment (LTRA), Sask Power uses a 13% reserve margin based on probabilistic analysis of Expected Unserved Energy. The specific EUE metric used to set the target was unavailable. This is different than LOLE in that it takes into account the magnitude of the event. NERC has recently recognized the fact that LOLE does not take into account the magnitude of the event and in its latest probabilistic assessments has requested that EUE as a percent of demand be used instead of LOLE.

- **Manitoba**

  Reliability Criterion: Both an energy criterion and a capacity reserve margin criterion due to the fact that the region is predominantly hydro.

  The energy criterion requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The reserve margin is at least 12%. Based on Manitoba's 2010/2011 Power Resource Plan[35], Manitoba states that "the reserve margin of 12% has been adequate for Manitoba Hydro's predominantly hydro based system because of the relatively low outage rates of hydro generating units combined with relatively small size units."

- **Mid Continent Area Power Pool (MAPP)**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Per the NERC's 2011 LTRA[36], some of MAPP's members self impose a planning reserve margin of 15% based on the LOLE study performed in 2009.

  Given that the focus of the paper surrounds the Eastern Interconnection, we have only included a few short comments on the ERCOT and WECC interconnections.

3. ERCOT

Reliability Criterion: 1-in-10 LOLE (LOLE of 0.1)

Although ERCOT performs a resource adequacy assessment to determine the reserve margin necessary to meet 1-in-10 LOLE, there is not a mandatory requirement for the region. ERCOT operates as an energy only market and therefore does not have mandatory capacity requirements.

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[34] *2011 Long-Term Reliability Assessment*, retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdf

[35] *Manitoba Hydro 2010/11 Power Resource Plan*, retrieved on September 3, 2012 from http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_84.pdf

[36] *2011 Long-Term Reliability Assessment*, retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdf

4. WECC

In general, each balancing area has responsibility for meeting resource adequacy standards established by respective states in which they operate. Resource adequacy planning in WECC is similar to that in SERC.

- **CAISO**

The California ISO uses a resource adequacy requirement of 15% reserve margin set by the California Public Utility Commission's Resource Adequacy Program. It is our understanding that the 15% was derived from previous resource adequacy studies.

- **NWPP**

The Pacific Northwest uses an LOLP metric that states the following: "the likelihood of having at least one curtailment five years into the future must be 5% or less for the power supply to be deemed adequate."[37] They also include another metric 2) conditional value at risk (CVaR) to evaluate the likelihood, magnitude, duration, and seasonality of Energy-Not-Served (ENS) events.

[37] Fazio, John, *Pacific Northwest Resource Adequacy Standard*, retrieved on September 3, 2012 from http://ewh.ieee.org/cmte/pes/rrpa/RRPA_files/LBP20120726/Item%2011%20-%20IEEE%20RRPA%20PNW%20Adequacy%2072712.pdf

III. PREVIOUS ECONOMIC STUDIES OF THE 1 DAY IN 10 YEAR STANDARD

A number of studies have been performed that evaluate the value of service reliability. The most common approach taken in these studies compares the direct and indirect costs of outages with the costs of generating capacity at a range of reserve margins. Some of the studies also take into account other benefits of reserve capacity including reduced purchase costs, offsetting higher cost resources, reducing the costs of voltage reduction, and reducing the costs of interrupting non-firm load customers. However, few of the studies surveyed explicitly estimate the reasonableness of existing physical reliability standards by comparing to economically optimal reserve margins. This is likely because the units of physical reliability events do not reflect their magnitude or duration. The cost of 1 event in 10 years is highly dependent on the size and duration of the event, neither of which is reflected in the metric. The following sections review specific studies of the value of service reliability.

A. ECONOMICS OF RELIABILITY FOR ELECTRIC GENERATION SYSTEMS (1973)

M.L. Telson's thesis titled the Economics of Reliability for Electric Generation Systems in 1973[38] was one of the earliest relevant studies which specifically addressed the reasonableness of physical reliability standards. His approach was similar to many of the other value of electric service studies which approximate an optimum reserve margin by comparing the cost of carrying additional capacity with the costs of outages at various reserve margins. Since his approach is used frequently, we will analyze it in some depth.

Mr. Telson does explicitly compare economically optimal reserve margins with reserve margins determined by physical metrics such as the 1-in-10 LOLE metric. His analysis suggests that reserve margins set by 1-in-10 LOLE are much higher than would be justified by an economic analysis. An economically set reserve margin might provide reliability as low as 1 event per year according to his analysis. A simplification of the related math states that 1 event per year with an outage cost of ~$1/kWh and a duration of 12 hours is comparable to the carrying cost of a new unit at $12/kW-yr. This is the optimal level because additional reserves would provide less than $12/kW-yr of avoided outages, and fewer reserves would result in more than $12/kW-yr of additional outages. Mr. Telson's analysis suggests that under typical reliability standards, customers are over-paying on a total cost basis by 4.1% compared to what they would pay under an economically optimal reserve margin even after considering societal outage costs. While the cost figures from 1973 are no longer applicable, more recent studies also make the point that it would take several hours per year of outages even with high outage costs to justify new capacity.

As additional support for a lower reserve margin target than indicated by the 1-in-10 LOLE standard, Mr. Telson compares generation adequacy related outages with transmission and distribution outages which are orders of magnitude more frequent. This report also highlights the conservative assumptions built into many of the 1-in-10 LOLE based reliability studies. Another limitation pointed out by Mr. Telson of most physical reliability studies is their lack of attention to the magnitude and duration of outages.

The support for Mr. Telson's position that an economic reserve margin should be less than a 1-in-10 LOLE target is dependent on the system conditions he assumed, many of which are not applicable to systems today. For example, in the early 1970's, load growth was

[38] *Economics of Reliability for Electric Generation Systems*, M.L. Telson, 1973

much higher with substantial uncertainty; unit performance was less reliable, the carrying cost of additional reserves was higher in real terms, and the cost of outages was lower in real terms. However, even with updated assumptions, we do not feel that Mr. Telson's approach considers all of the economic factors necessary for valuing the benefits of additional capacity. In fairness, his economic analysis is much more sophisticated than suggested by our example and includes a number of indirect economic impacts in addition to the direct costs mentioned.

B. Cost and Benefits of Over/Under Capacity in Electric Power System Planning (1978)

Another early significant study in our research results is titled 'Costs and Benefits of Over/Under Capacity in Electric Power System Planning' and was performed for EPRI in 1978[39]. This study analyzed the economics of generation reliability for 4 utilities (Tennessee Valley Authority, Pacific Gas and Electric, Long Island Lighting Company, and Wisconsin Electric Power Company). This study uses a number of unique assumptions:

1. Load growth and capacity expansion uncertainty are primary drivers of the need for planning reserves. This is primarily a function of the high load growth period of the 1970's and is likely not applicable today.
2. Total variable costs for each different reserve margin level studied must be incorporated into the total cost comparison; not just the outage costs and capital costs. This analysis included the variable production costs of each unit plus the cost of purchasing electricity from interties, interrupting certain customers, and reducing voltage.
3. Environmental cost differences between different reliability levels should also be considered. While the costs were not explicitly included in the analysis, qualitative consideration was given to the environmental benefits or penalties at different levels of service reliability.

The study also results in a number of unique observations:

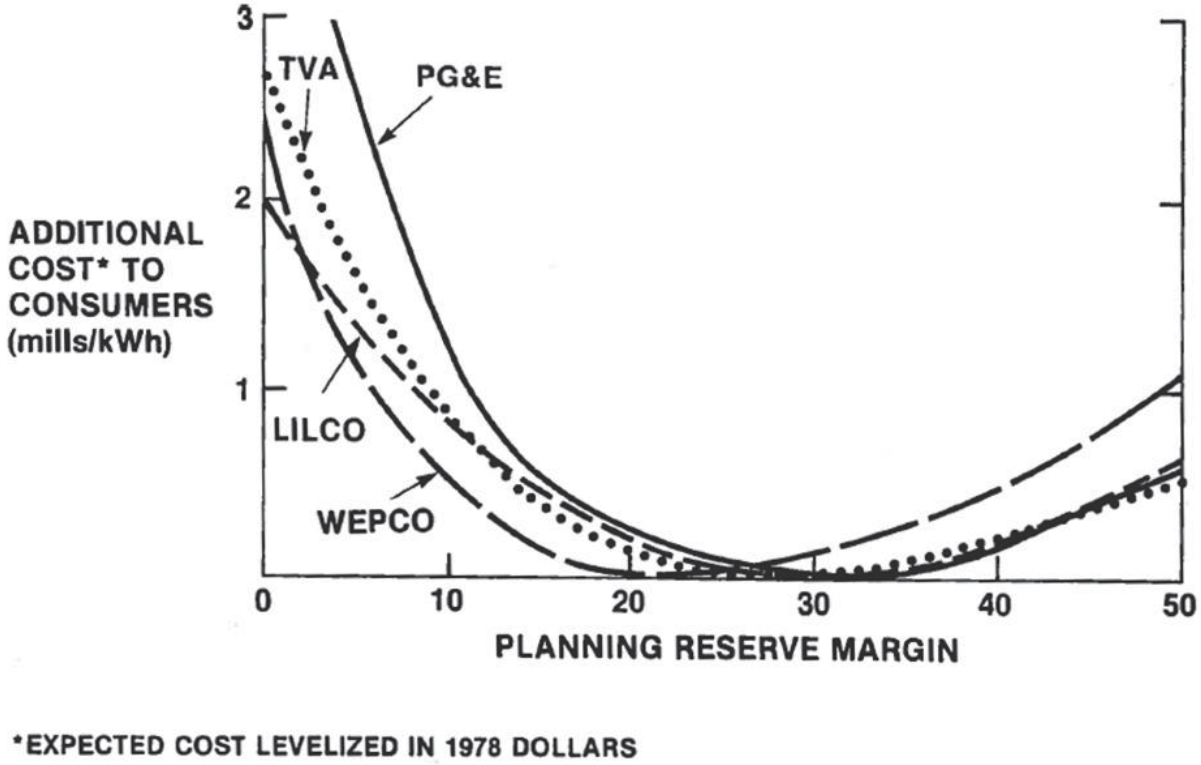
1. Asymmetry of Consumer Cost. Reserve margins much below the optimal reserve margin tend to have much higher costs than reserve margins much above the optimal reserve margin. This suggests that if two reserve margin levels have the same expected value, the higher reserve margin is a more appropriate selection based on its lower risk profile.
2. The total cost curve is relatively flat at a wide range of reserve margins near the optimal economic reserve margin. This also supports carrying higher reserve margins since the cost differences are not substantial.
3. The economically optimal reserve margin can vary substantially depending on the resource mix, unit performance, load and load growth profile, and other factors. The optimum reserve margins for the 4 utilities studied ranged by approximately 15%.

[39] Decision Focus, Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning,* EPRI EA-927, Project 1107, October 1978

4. Old technologies can have a substantial impact on the economically optimal reserve margin. If the marginal unit used to increase or decrease reserves has an operating cost less than a substantial portion of a utility's existing resources, the economically optimal reserve margin may be quite high. Regardless of how high the reserve margin is, as long as adding resources is offsetting the dispatch of a significant portion of existing resources, their addition could be economic.

The results of the analysis indicate that reasonable economic reserve margins fall in the range of 15% to 40% as shown in the Figure 2 below. While the study did not explicitly compare these reserve margin levels to 1-in-10 LOLE based reserve margins, the paper suggests that economic reserve margins are not necessarily lower than reserve margins determined by physical reliability metrics. Further, even at reserve margins above those standards, the additional costs are not that substantial. This conclusion is counter to a number of other value of service studies that indicate that economically set reserve margins are always lower than 1-in-10 LOLE based reserve margins.

Figure 2. Total Costs as a Function of Planning Reserve Margin

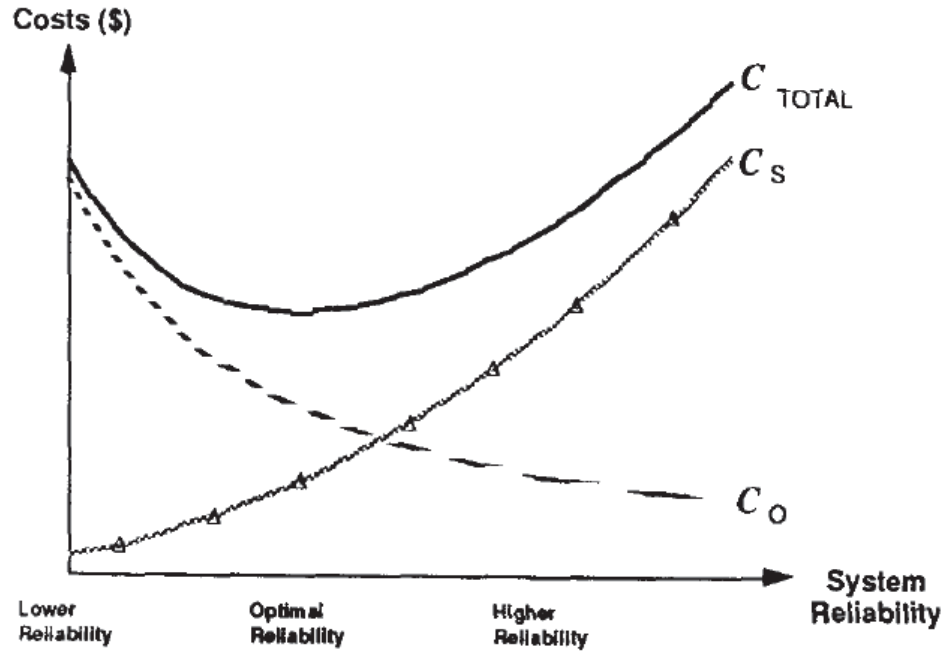


C. PGE VALUE OF SERVICE RELIABILITY (1990)

In 1990 Sandra Burns and Dr. George Gross authored a paper called Value of Service Reliability[40] that studied the Value of Service approach to resource adequacy planning. Ms. Burns and Dr. Gross begin by stating valid points why physical metrics such as LOLE and LOLP are somewhat arbitrary and don't take into account the economic impact on customers. For example the paper said "it is difficult to determine from a societal point of view whether a 1 day in 10 years LOLP is more appropriate than 1 day in 5 years or 1 day in 20 years."

Next the paper discussed the Value of Service framework in which the marginal costs of additional reserves are compared against the marginal benefit of additional reserves. Figure 3 summarizes this method. Co represents cost to customers when demand cannot be met and Cs represents capital investment expenditures. As reliability increases (or reserve margin increases), investment expenditures increase while customer costs due to the utility not meeting demand decrease. At some point the benefit of the additional capacity is not justified.

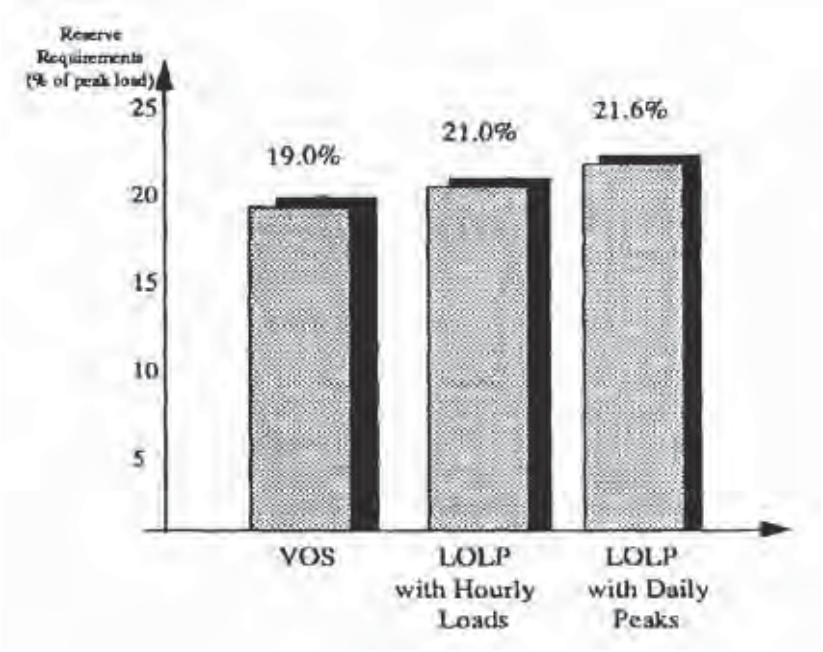
Figure 3. Variation of Costs as a function of reliability



To develop a proper estimate for Co, PGE used recent customer outage surveys which resulted in a weighted average customer cost of $3/kWh. Next, the author compared the economic approach to two different physical reliability metrics. The first approach used hourly loads and calculated the reserve margin assuming an LOLH of 2.4 hours per year while the second method used daily peaks to calculate an LOLE of 0.1 days per year. The results are seen in Figure 4. The economic approach produced a lower reserve margin than the traditional physical reliability approaches.

[40] Burns, Sandra and Gross, George, *Value of Service Reliability*, IEEE Transactions on Power Systems, Vol.5, No.3, August 1990

Figure 4. Value of Service vs. LOLP



The study implies a general relationship that a reserve margin based on value of service would be less than the 1-in-10 LOLE metric.

D. On an 'Energy Only' Electricity Market Design for Resource Adequacy (2005)

While this paper[41] by William Hogan was not specifically designed to address the economic reasonableness of using specific physical reliability metrics to set target reserve margins, it does address resource adequacy and the missing money problem in structured markets. Mr. Hogan's paper provides informative insights into the economics of resource adequacy from the perspective of generators. He proposes a number of improvements to the design of energy markets that could alleviate the need for additional capacity payments and still provide generators adequate revenue to cover their costs. He recognizes that in current markets, many generators do not fully recover their costs. His explanation for this gap is that "the missing money problem arises when occasional market price increases are limited by administrative actions such as price caps." While we agree that price caps are certainly a component of missing money, in the absence of a reserve margin target, generators theoretically should offer less capacity to the market such that, even with the price caps in place, generators still receive adequate revenue. Imagine a system with price caps at $500/MWh. With this low cap, fewer generating assets should be built since they can't expect adequate returns at a higher reserve margin. This lower reserve margin will result in scarcity situations more frequently producing adequate returns for marginal generators, however the tradeoff would be that physical reliability would decline.

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[41] Hogan, William (2005), "On an “Energy Only” Electricity Market Design for Resource Adequacy."

We are not suggesting that an energy market with low price caps is an ideal market structure. We are simply illustrating that regardless of market structure, generators should theoretically target a reserve margin that produces adequate returns regardless of the reliability implications.

One aspect of Hogan's solution for the missing money problem is to eliminate price caps and implement an administrative scarcity pricing curve. He states: "For any level of capacity that provides a given level of reliability, there is some set of shortage prices that would produce generator revenue streams that if correctly anticipated would be sufficient to sustain that level of capacity." While this is a valuable insight, it does not speak to whether the given level of reliability is economically appropriate. Hypothetically, the given level of reliability could require a 30% reserve margin. The administrative scarcity pricing curve would have to be extremely high, well above the true value of the reserves, in order to achieve cost recovery.

E. RECONSIDERING RESOURCE ADEQUACY: HAS THE ONE-DAY-IN-10-YEARS CRITERION OUTLIVED ITS USEFULNESS? (2010)

Mr. James Wilson recently published an article[42] in the Public Utilities Fortnightly examining the one-day-in-ten year standard and whether or not it was economic. Mr. Wilson states "The 1-in-10 criterion always has been highly conservative--perhaps an order of magnitude more stringent than the marginal benefits of incremental capacity can justify—and capacity planning has been even more conservative in practice." He uses examples comparing the Value of Lost Load x LOLE x hours per event to Net Cost of New Entry (CONE) which represents the capital costs of a new combustion turbine net of energy and ancillary service revenues as shown in the table below. Utilizing the examples, in all cases the optimal amount of LOLE is higher than the 0.1 LOLE standard as shown in the following table. For example, in order to justify a $120,000/MW-year Net CONE, the resource must offset 6 LOLE events per year assuming 5 hours per event and a VOLL of $4,000/MWh. (Note: the units from the article for VOLL should be $/MWh and the units of Net Cone should be $/MW-yr)

[42] Wilson, James, *Reconsidering Resource Adequacy*, retrieved on September 4, 2012 from http://www.fortnightly.com/uploads/04012010_ResourceAdequacyP11.pdf

Table 3. Optimal LOLEs for Various VOLL and Capital Cost Assumptions

Value of service (VOLL)	Net Capital Cost (Net CONE)	Hours per outage event	Optimal LOLE	Optimal Nines
$/MW-year	$/MWH	hours/event	events/yr	
$4,000	$120,000	5	6.0	2.5
$4,000	$80,000	5	4.0	2.6
$4,000	$40,000	5	2.0	2.9
$2,000	$120,000	5	12.0	2.2
$2,000	$80,000	5	8.0	2.3
$2,000	$40,000	5	4.0	2.6
$20,000	$120,000	5	1.2	3.2
$20,000	$80,000	5	0.8	3.3
$20,000	$40,000	5	0.4	3.6

Moreover, Mr. Wilson states the following: "The tendency is often to adopt conservative assumptions for many of these values, to make the overall result of the analysis conservative (i.e. erring on the side of too much rather than too little capacity and reliability, identifying too large rather than too small a reserve margin)." In conclusion, Mr. Wilson argues that the 1-in-10 LOLE standard is not an economic target and that economics would indicate much lower target reserve margins.

Mr. Wilson's article is primarily targeted toward the PJM system. In agreement with his assessment of PJM, our review of regions in the Eastern Interconnection indicates that PJM's planning study assumptions are potentially conservative. However, in concurrence with our other assessments, we believe that Mr. Wilson is not including some key components of the value of marginal capacity in his analysis. A marginal resource provides substantially more value than simply displacing firm load shed events.

F. THE ECONOMICS OF RESOURCE ADEQUACY PLANNING: WHY RESERVE MARGINS ARE NOT JUST ABOUT KEEPING THE LIGHTS ON (2010)

Astrape Consulting cooperated with the Brattle Group to write the paper titled "The Economics of Resource Adequacy Planning"[43] which was published by NRRI in April of 2011.

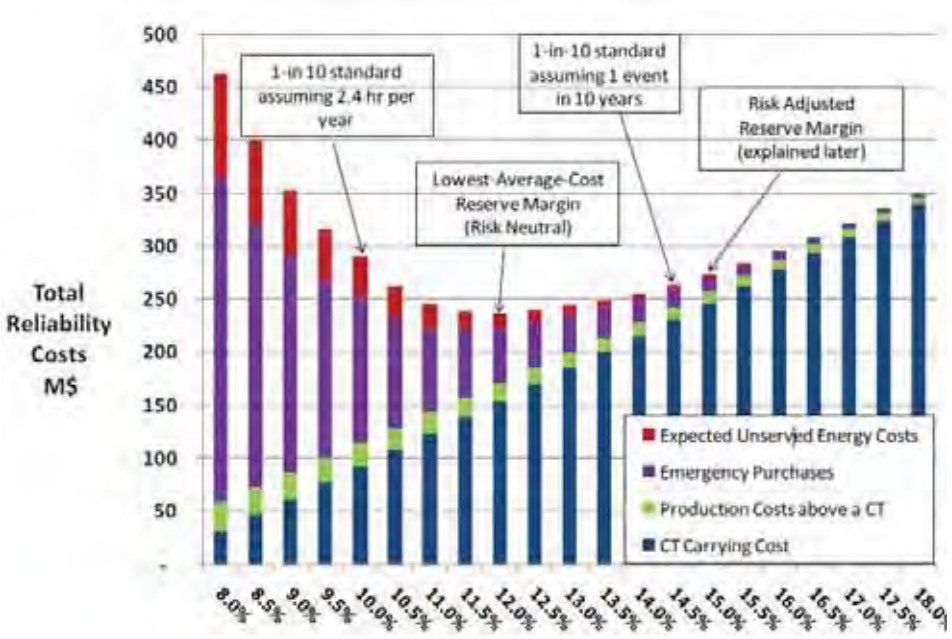
The paper describes an economic approach to resource adequacy planning and compares it to results utilizing two different definitions of the 1-in-10 LOLE standard. The authors develop a case study using a resource adequacy model that not only calculated LOLE but also takes into account economic dispatch and costs. The methodology balances the cost of new capacity (CT) with the benefit the resource provides. In this study, the benefit is defined as the following:

[43] Carden, Pfeifenberger, Wintermantel, *The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On, NRRI, April 2011, retrieved on September 3, 2012 from* http://www.nrri.org/pubs/electricity/NRRI_resource_adequacy_planning_april11-09.pdf

- Production-Related Reliability Costs – defined as any costs of the system's physical generation above the dispatch cost of the new capacity resource. This includes the dispatch of higher-cost generators such as oil-fired turbines and old natural gas turbine units. The addition of a new capacity resource would offset some but not all of these costs.
- Emergency Purchase Costs – defined as the costs of any purchases at prices higher than the cost of the marginal capacity resource. In our simulations, these emergency purchase costs, including purchases associated with demand-side resources, can range from $1/MWh above the dispatch cost of a CT to the cost of unserved energy (*e.g.*, well in excess of $1,000/MWh) under extreme conditions.
- Unserved Energy Costs – The value of lost load to customers. This value typically is derived from customer surveys.

The point is made that the majority of costs from the California Energy Crisis were comprised of expensive energy prices in the marketplace and not due to firm load shed. A marginal resource has the ability to reduce scarcity pricing events as well as reduce firm load shed events. The results of the study are seen below. The economic reserve margin target (Lowest-Average-Cost Reserve Margin) was higher than a 2.4 LOLH based reserve margin and lower than a 1-in-10 LOLE based reserve margin. The authors make the point that dependent on the system, the economic reserve margin could be higher or lower than the 1-in-10 LOLE target.

Figure 5. Lowest Average Cost Reserve Margin



The fundamental distinction of this study is that there is a significant focus on the costs of emergency purchases and the impact of scarcity pricing in markets. Dependent on the severity of the weather and load forecast uncertainty in a particular case, it is reasonable to assume that a CT could be dispatched 0 hours up to 1,500 hours in a given year. In years where a CT is dispatched substantially, it is important to recognize all the benefits the resource provides. Alongside the weighted average or expected results, the authors discuss the importance of understanding the full distribution of potential costs from all scenarios comprised of combinations of weather and load forecast uncertainty. Given that reliability

events are low-probability high-impact events, the tails of the distribution of possible scenarios are important.

One of the critiques of the approach put forward by Brattle and Astrape is that there was no weather diversity considered causing the scarcity pricing to be too high, and that the load forecast error distribution assumed provides limited flexibility in adjusting resource plans if load grows faster than expected. Reviewers have suggested that the conservative nature of these assumptions led to higher than optimal reserve margins. These critiques have been considered by the authors and have been incorporated in the simulations for this white paper. For example, each region's load was modeled based on hourly historical weather to ensure proper weather diversity is taken into account.

Additional Scholarly Works that Address the Economics of Reliability:

- Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity (1988) by Biewald and Bernow
- Reliability Evaluations of Power Systems, Billinton (1990)
- Southern Company Reserve Margin Studies (1997, 2004, 2007, 2009)
- Louisville Gas and Electric Reserve Margin Study (2010)
- Peter Cramton and Steven Stoft (2006), "The Convergence of Market Designs for Adequate Generating Capacity."

In summary, we reviewed multiple economic studies which assessed the reasonableness of the 1-in-10 LOLE standard and summarized the findings of 6 of those studies. The EPRI Over/Under study and the study produced by Astrape Consulting/The Brattle Group demonstrated economic target reserve margins that could be below or above LOLE 1 day in 10 year targets. The remaining studies (Telson, PGE VOS, Wilson) all implied that the economic target would likely be lower than the 1-in-10 LOLE target. Given the sensitivity of the results to input assumptions, it is likely that changes to the cost of carrying capacity, the value of lost load, and load uncertainty since some of those studies were published would affect conclusions. Further, in reviewing methodologies, the major difference was defining the benefits that a marginal resource provides. The benefits defined varied across the studies from including all costs above the dispatch cost of a CT (i.e. emergency purchases, DR costs, and unserved energy) to only including the Value of Lost Load to customers.

Economists may argue that the economic optimal target should only be based on total societal costs which would include only total production costs (fuel burn + O&M) plus the cost of unserved energy and ignore the scarcity pricing situations that occur in the market place. The argument is that these high cost purchases only represent a transfer of wealth from one region to another or from customers to generators rather than an actual societal cost. However, the approach of only considering net societal costs largely ignores the bigger question of how costs and revenues are shared among the participants in the system. Assume an example system minimizes total societal costs at a reserve margin of 8%, and at this level total societal costs annually are $5 billion in fuel, O&M, and capital costs. When the economics of each participant are considered however, there may be significant market distortions. If this was an energy-only system and reserves approximately matched the minimum societal cost reserve margin of 8%, significant scarcity would be prevalent. The market price in many hours would be set by scarcity pricing even though the total production costs are still minimized at this low reserve margin. Because of this scarcity, generators may extract $8 billion in energy costs from consumers in a given year, a $3 billion transfer of

wealth. This is ignored in the societal cost minimization approach, but represents a significant concern.

In competitive markets, if there is a distortion resulting in a transfer of wealth from consumers to generators, then new generation would theoretically enter the market until the marginal unit is only recovering its costs. The new capacity would raise the reserve margin and eliminate the wealth transfer. But now the system is no longer targeting the optimum reserve margin based on minimizing societal costs. The reserve margin target becomes the level at which generators recover costs. But as we will discuss in later sections of the report, total systems costs in an energy only market at the point of generator cost recovery may not be optimal when compared to other potential market structures.

The minimization of net societal costs approach is instructive in a number of ways. If an entire system consists only of vertically integrated utilities, and all transfers are passed on to customers at cost, and planning is coordinated between all utilities, the minimization of net societal costs is theoretically correct. The results from such an analysis could be compared to the minimum customer cost approach for a single utility to identify the magnitude of the inefficiency due to not coordinating all planning activities.

IV. VOLL ESTIMATES AND THEIR IMPACT ON RESOURCE ADEQUACY PLANNING

Over the last several decades, there have been many customer surveys and studies performed to estimate the value of lost load to customers. Two comprehensive studies which aggregated many of the individual surveys were performed for the U.S. Department of Energy (DOE) by Ernest Orlando Lawrence Berkeley National Laboratory in November 2003 and updated again in June 2009[44]. For this analysis, we will focus on the results from the June 2009 study. The study takes results from 28 customer value of service reliability studies conducted by 10 major US electric utilities over the 16 year period from 1989 to 2005. The majority of these studies are not available publicly and were only made available by utilities for this specific DOE study. The results were combined into a single meta-database and a regression model was developed to calculate customer costs per event by season, time of day, day of week, and geographical regions within the U.S.

The study divided customer groups into the following:

- Medium and Large Commercial and Industrial (more than 50,000 annual kWh usage)
- Small Commercial and Industrial (less than 50,000 annual kWh usage)
- Residential Customers

The following tables summarize the data found in the study.

Table 4. Value of Lost Load Summary: Summer Weekday Afternoon

Interruption Cost $/event	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I	$ 11,756	$ 15,709	$ 20,360	$ 59,188	$ 93,890
Small C&I	$ 439	$ 610	$ 818	$ 2,696	$ 4,768
Residential	$ 2.70	$ 3.30	$ 3.90	$ 7.80	$ 10.70

$/kWh Unserved Energy at Customer Peak*	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I		$ 30.83	$ 19.98	$ 14.52	$ 11.52
Small C&I		$ 85.50	$ 57.33	$ 47.23	$ 41.77
Residential		$ 1.30	$ 0.77	$ 0.38	$ 0.26

[44] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, June 2009

*Peak Loads used to calculate interruption costs in $/kWh for each customer class were based on reported average kWh energy use and assumed an 80% load factor for medium and large customers, 40% load factor for small customers, and 30% load factor for residential[45]

In performing economic resource adequacy analysis, the $/kWh value associated with unserved energy at peak is the value that is typically used as the Value of Lost Load assumption. Assuming that firm load shed would be spread equitably among all customer classes, a weighted average of the system's customer class mix can be calculated to develop a system $/kWh value for the region being studied. The weighted average $/kWh for Unserved Energy using the 1 hour values is $26.02/kWh.

The table shows that as the duration of the outage increases, the $/kWh value decreases. The first hour is typically the most expensive as customers have an opportunity to mitigate the impact of an outage in subsequent hours. The results also show that Residential Customers have the lowest costs while Small C&I Customers have the greatest costs. This is logical as residential customers generally only have some discomfort and minor loss such as spoiled food during outages. We typically see the VOLL for residential customers to be less than $3/kWh. Businesses have a much higher cost. Technology has been a major driver for the increase in commercial business outage costs as computer systems have become so vital in today's work environment. For retail business, there is lost sales revenue as businesses may be forced to close during the outage. For industrial customers, the costs of lost product and lost revenue drive the estimates.

The next table shows how outage costs varied by season, day of week, region, and industry. It is seen that depending on the industry and size of the business, the VOLL can vary greatly. For Medium and Large C&I Customers, the outage costs can vary from $2.8/kWh to $40.9/kWh depending on the industry. For Small C&I Customers, costs range from $21.7/kWh to $108.7/kWh. VOLL is an uncertain value, but as our case study demonstrates, the assumption does not have a significant impact on the economics of resource adequacy. In a system that is planning to the 1-in-10 LOLE standard, the amount of expected unserved energy (EUE) is small and therefore limits its impact on economic results. While the raw average estimates from the aggregated studies indicated a much higher VOLL, due to the large variance in VOLL estimates, $15,000/MWh was assumed in the case study as a blended rate for residential, commercial, and industrial customers.

[45] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, June 2009; Table ES-1 costs per event were converted to $/kWh based on the peak load assumption for each customer class.

Table 5. Cost per Event across Season, Day, Region, and Industry[46]

	Cost per Event of 1-Hour Outage					
	Medium and Large Commercial and Industrial Customers 2008$		Small Commercial and Industrial Customers 2008$		Residential Customers 2008$	
Season	Costs $	$/kWh*	Costs $	$/kWh*	Costs $	$/kWh*
Winter	$ 11,129	$ 10.9	$ 543	$ 38.1	2.9	$ 0.6
Summer	$ 15,628	$ 15.3	$ 737	$ 51.6	4.7	$ 0.9
Day						
Weekend	$ 2,249	$ 2.2	$ 459	$ 32.2	8.6	$ 1.7
Weekday	$ 16,478	$ 16.2	$ 765	$ 53.6	4	$ 0.8
Region						
Midwest	$ 12,294	$ 12.1	$ 732	$ 51.3		
Northwest	$ 3,552	$ 3.5	$ 341	$ 23.9	3.2	$ 0.6
Southeast	$ 23,797	$ 23.4	$ 799	$ 56.0	6.6	$ 1.3
Southwest	$ 5,946	$ 5.8	$ 967	$ 67.8	1.8	$ 0.4
West	$ 18,166	$ 17.8	$ 886	$ 62.1	3.7	$ 0.7
Industry						
Agriculture	$ 1,063	$ 1.0	$ 352	$ 24.7		
Mining	$ 18,501	$ 18.2	$ 1,545	$ 108.3		
Construction	$ 3,663	$ 3.6	$ 1,301	$ 91.2		
Manufacturing	$ 41,691	$ 40.9	$ 913	$ 64.0		
Telco. & Utilities	$ 8,837	$ 8.7	$ 810	$ 56.8		
Trade & Retail	$ 2,818	$ 2.8	$ 627	$ 43.9		
Fin., Ins. & R.E.	$ 5,790	$ 5.7	$ 975	$ 68.3		
Services	$ 4,810	$ 4.7	$ 531	$ 37.2		
Public Admin	$ 12,239	$ 12.0	$ 310	$ 21.7		

*Peak Loads for each customer class were based on the report's average kWh energy use and assumed an 80% load factor for medium and large customers, 40% load factor for small customers, and 30% load factor for residential [47]

Based on the variation of VOLL values provided by businesses, it is easy to recognize the need for demand response programs with different characteristics. For a customer with very low outage costs, it would be rational for them to curtail load when prices reach a threshold of $150/MWh while a customer who has high outage costs and no backup generation would likely not participate in a program. As part of the simulation portion of this paper, we analyze what happens to reliability as the penetration of demand resources increase without increasing the dispatch constraints. As DR penetration increases, energy prices will increase and DR resources will be called upon much more frequently. The estimation of

[46] No studies available to be summarized for black shaded cells.

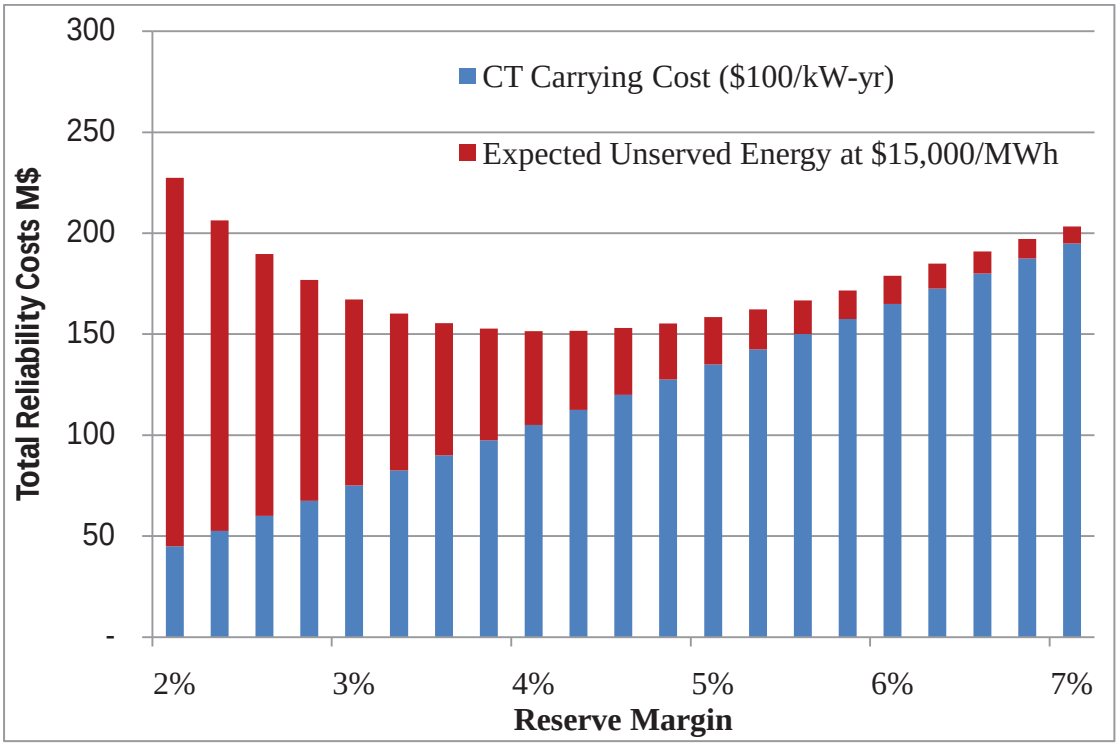
[47] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, June 2009; Table 3-4, Table 4-4, and Table 5-4 average costs per event were converted to $/kWh based on the peak load assumption for each customer class.

these calls is going to be vital to resource adequacy planning in the next decade, particularly because DR resource participants are voluntary participants who may choose to discontinue participation if DR resource use hits thresholds of tolerance.

V. DETERMINING THE OPTIMAL RISK NEUTRAL AND RISK ADJUSTED ECONOMIC RESERVE MARGIN

Most of the research papers cited in Section III compared the cost of incremental capacity to the economic benefit of reduced unserved energy costs provided by the capacity under a vertically integrated utility environment. As an example of this methodology, if adding new capacity costs $100/kW-yr, and the value of lost load is $15,000/MWh, the new capacity would need to offset more than 6 hours of lost load per year to be economically justified. However, since the 1-in-10 LOLE standard represents only 0.3 hours of lost load per year, the economic reserve margin would be much lower than the 1-in-10 LOLE based reserve margin as shown in the Figure 6 below. The economic reserve margin is 4% in our case study if only EUE is taken into consideration as the benefit additional capacity provides. Again, this is the economic reserve margin for this particular analysis because adding capacity up to a 4% reserve margin costs less than the economic societal benefits of reduced EUE for this region. Above a 4% reserve margin, adding capacity costs more than the economic societal benefits produced in reducing EUE. A 4% reserve margin results in the minimum capacity plus EUE costs.

Figure 6. Cost of Capacity vs. Reduction in Expected Unserved Energy Costs



However, system planners should be attempting to minimize total system costs to customers, not just a subset of system costs. Every benefit of incremental capacity should be considered. In addition to avoiding the societal costs of shedding firm load, adding new efficient gas turbines would avoid the dispatch cost of many inefficient existing units and avoid expensive market purchases during hours when capacity is scarce. When taking these additional benefits into consideration, total system costs continue to drop as capacity is added well above a 4% reserve margin.

In the following case study we will explore potential methods of determining a risk neutral and optimal risk adjusted target based on total system costs to customers.

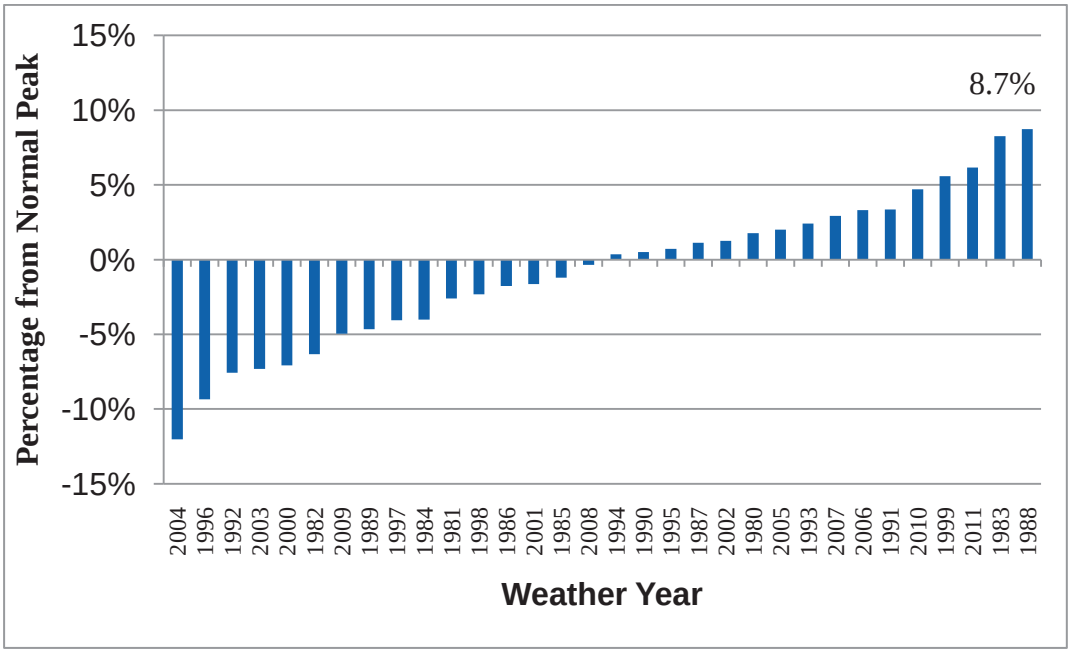
A. CASE STUDY DESCRIPTION

The following is a brief overview of the case study setup. The Eastern Interconnection Planning Collaborative (EIPC) has recently performed its Eastern Interconnection Transmission Study. The primary objective of the EIPC study was to aggregate the modeling and regional transmission expansion plans of the entire Eastern Interconnection and to perform regional analyses to identify potential conflicts and opportunities between regions. The EIPC study simulates all loads, generating resources, and transmission resources for all individual regions. Input data for the case study presented in this report uses data from the EIPC study as inputs, including region definitions, load forecasts, generating resource mixes, and transmission capabilities. Because the scope of this white paper was limited, only a subset of 14 of the NEEM regions from the EIPC study was included. For resource adequacy studies, accurate representation of the uncertainty in loads and generator availability is necessary to capture the frequency of reliability events. Firm load shed and extremely high market prices are typically only concerns when loads are much higher than normal or generating resources are less available than normal.

To accommodate this additional uncertainty, we included distributions around the following variables:

- Weather Uncertainty. Figure 7 demonstrates that summer peak load could be as much as 8.7% higher than normal peak load due to weather uncertainty in the PJM Rest of MAAC (PJM ROM) region. This is fairly typical across most of the regions in the Eastern Interconnection. Weather also impacts hydro, thermal, and intermittent resources which was also captured in the case study (See Appendix A).

Figure 7. Weather Impact on Peak Load for PJM Rest of MAAC



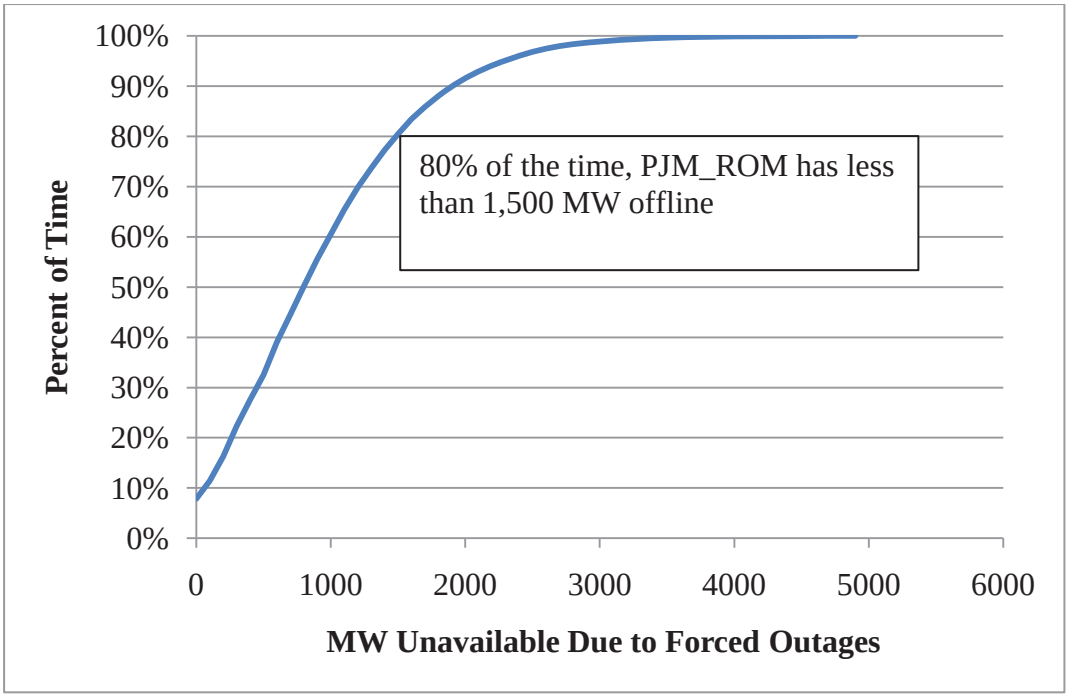
- Load Forecast Uncertainty. All loads for a given year could be as high as 5% higher (although this has a very low probability of occurring) than normal due to unexpected economic growth over a 4 year period as seen in the distribution in the Figure 8. The 6 discrete points in the table with associated probabilities were used in the simulation. This economic uncertainty captures the boom-bust cycle inherent in electric markets. Some years the market will have excess capacity above the target reserve margin and other years markets will be below the target reserve margin. This error distribution was developed from analyzing how well the Congressional Budget Office was able to forecast GDP three to four year out. That distribution of performance was translated to electric demand using a multiplier of .4% load growth for every 1% of GDP growth. The development of this distribution is further explained in the Appendix A.

Figure 8. Economic Load Forecast Error

Load Forecast Error	Probability
5.11%	6.25%
3.90%	18.75%
0.55%	31.25%
-1.76%	18.75%
-2.90%	12.50%
-4.54%	12.50%

- Unit Performance Uncertainty. Figure 9 shows that the study system is expected to have approximately 800 MWs in a forced offline state on average, but there are hours in which the system could have 2,000 MWs offline. The figure also shows that 80% of the time the region will have less than 1,500 MW offline due to forced outages.

Figure 9. Unit Performance Distribution



Additional modeling details can be found in Appendix A.

Each scenario modeled in SERVM[48] consists of one economic forecast error point and one weather year. The first scenario simulated used 1980 historical weather and a 5% under forecast of load growth. To build the loads for this year, the 8760 hour loadshape from the source weather year was multiplied by the economic forecast error multiplier. The resulting 8760 hour loadshape represents what the hourly loads would be expected to be in 2016 if the system experienced the same temperatures as 1980 and loads grew 5% faster than expected due to economic growth. This discrete scenario was simulated for 400 iterations. Each iteration runs for all 8760 hours for a single projected year (2016) attempting to match load and resources at the lowest system cost. Several stochastic variables including unit performance and dispatch error are used and result in independent costs and metrics for each iteration. The average of all the system costs and physical reliability metrics from all these iterations represent the expected values for this scenario.

In all, this process is repeated 192 times. Thirty two weather years combined with 6 economic forecast error points create 192 discrete scenarios. Simulating these scenarios for 400 iterations results in a full distribution of possible outcomes for the year 2016. It should also be noted that this process is applied to all regions in the study. When a 1980 weather year is being simulated, it is used for all regions. This modeling ensures that the actual differences in weather for each respective hour across the study system are captured. For example, when simulating July 9th, 1980, the loads for every region were developed using temperatures from July 9th, 1980. As the sensitivities demonstrate, the ability for one balancing area to provide assistance to another is critical, and understanding load diversity is a necessary component to that ability.

For this particular case study, we focused on the PJM Rest of MAAC (PJM_ROM) NEEM region from the EIPC Study. Although in reality this region is a participant in a structured market, for purposes of the base case analysis, it is treated as a vertically integrated utility. The purpose for this assumption is to simplify the economic comparison. When treated as a single vertically integrated utility, most of the internal load is served by resources within the region at those units' production cost. Purchases from outside the region are also assessed at their production cost unless the region is in a scarcity situation. Capacity is self-owned or procured through bilateral transactions between the utility and generators. Modeling the base case this way allows costs for consumers to be easily calculated. The economic reserve margin is based on minimizing total system costs for consumers. The applicability of this analysis to structured markets is discussed in section D of this chapter.

For this study, we set planning reserve margins for all other regions to their defined EIPC Study targets. Next, simulations were run for the study region from 10% reserves to 20% reserves in 2% intervals. To achieve the higher reserve margin levels, natural gas combustion turbine capacity was added. At each reserve margin level, LOLE, total system costs, and hourly market prices were tabulated. While the intent of economic reserve margin planning is to minimize total system costs to customers, the only difference between reserve margin levels is the addition of efficient CT capacity, so all base load costs can be ignored. Only costs that are above the dispatch costs of the marginal CT are tracked which represent the difference in total system costs. These system costs are made up of the following components:

[48] SERVM is an economic resource adequacy model that is used by utilities to develop optimal reserve margin targets using economics as well as LOLE.

1. Production Costs above the dispatch cost of a CT (i.e. the dispatch of oil resources)

2. Net Purchases above the dispatch cost of a CT. Anytime the studied region purchased or sold at costs higher than the marginal cost of a CT, the net purchase costs were tabulated.

3. Unserved Energy Costs (MWh of unserved energy * VOLL) For the base case, the VOLL of was assumed to be $15,000/MWh. A sensitivity around this assumption is included in the sensitivity section.

4. Carrying Cost of additional CT Capacity. For the base case, $100/kW-yr was assumed. Results will be shown ranging from $80/kW-yr to $120/kW-yr.

   For the case study, reserve margin was defined as the following:

   Reserve Margin = (Total Capacity Resources – Expected Peak Load) / (Expected Peak Load)

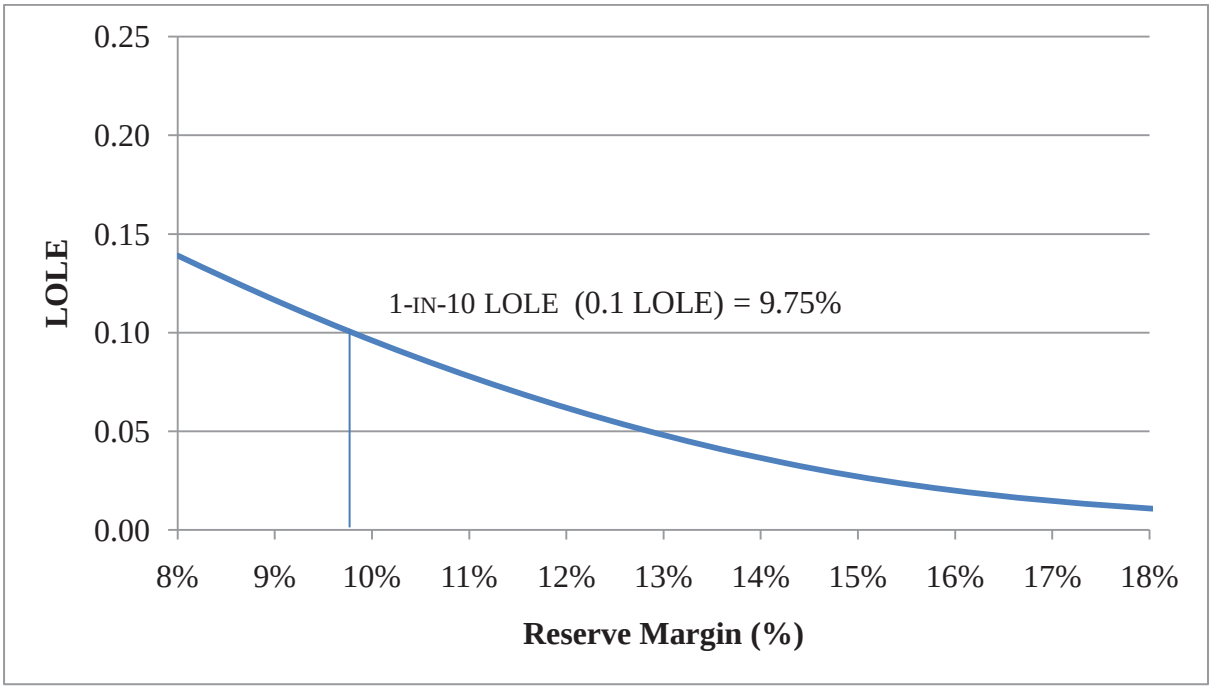
   where total resources includes all demand response resource capacity and the effective load carrying capability of wind and solar resources. See the appendix for these effective load carrying capability values.

B. Base Case Results Assuming a Vertically Integrated Utility

The following figures and sections discuss the Base Case Results.

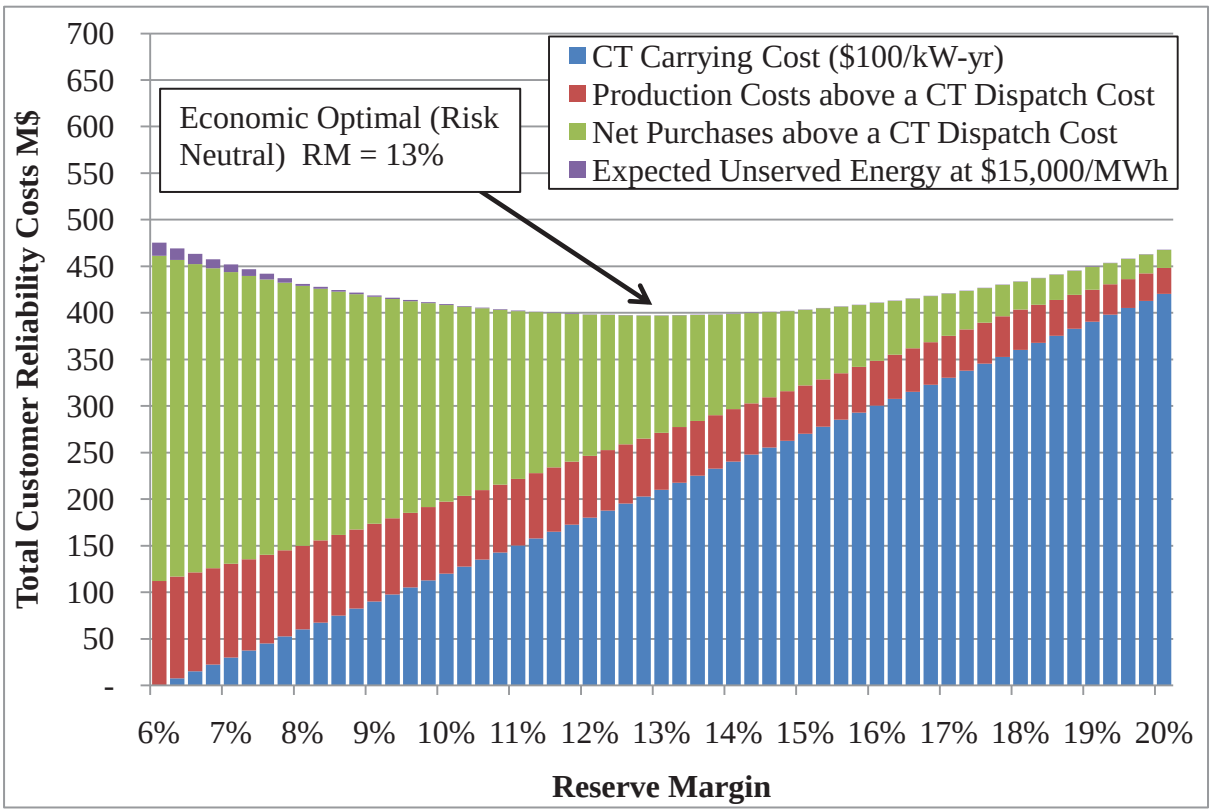
Figure 10 demonstrates that the reserve margin needed to meet the 1-in-10 LOLE standard (LOLE of 0.1) for the PJM_ROM region is 9.75%. An LOLH of 2.4 was met at below 8%. It should be noted that LOLE results are sensitive to input assumptions. As noted in the review of resource adequacy studies, PJM's own assessment indicates 1-in-10 LOLE for the entire PJM RTO falls at 15.3%. The two studies are not directly comparable since this analysis only considers one sub region of PJM and only generic unit outage data was used instead of utilizing actual historical generator availability data. However, one significant reason for this difference is that the PJM study assumes 3,500 MW of import capability, whereas the EIPC inputs assume 9,000 MW+ of import capability. Also, PJM derates 1,800 MW on peak due to temperature. The point here is not to challenge assumptions, but rather to demonstrate how large of a difference the selection of various inputs can change the results of the study. In addition to these, a number of other components that had the capability of shifting the 0.1 LOLE reserve margin by several percentage points were identified– at what point is demand response dispatched, will regions dispatch high cost or energy limited resources to support other regions, will a region shed firm load to maintain operating reserves, how much load diversity can be expected between regions, and will emergency hydro be available during peak load conditions. A few of these questions are addressed in the sensitivity section. While these assumptions can make a substantial difference in LOLE, they only affect a few hours per year or per decade, thus they typically don't have a meaningful impact on total costs or change the optimal economic reserve margin. Since the optimal economic reserve margin is affected by a much larger set of hours and events, it is typically less sensitive to minor inputs.

Figure 10. LOLE



The following figure, Figure 11, demonstrates the differences in system costs at a variety of reserve margin levels. The PJM ROM system represents ~30,000MW at peak load. A change of 1% reserve margin is approximately 300 MW. The carrying cost of this change is $30M/yr assuming the cost of capacity is $100/kW-yr. By adding this incremental capacity when the system is at a 10% reserve margin, total system energy costs (all production costs and purchase costs above the dispatch cost of a CT plus the cost of societal unserved energy) drop by $43M/yr and therefore justify the additional capacity. The additional capacity met a number of distinct needs. In some hours, the additional capacity was used to avoid high cost purchases. In other hours, the capacity avoided the dispatch of high cost resources such as oil turbines. During scarcity pricing conditions, the additional capacity may have avoided purchase costs and lowered market prices. A system that has 300 additional MW available will have lower scarcity prices than one which is 300 MW closer to not being able to serve firm load. And in extreme conditions, the additional capacity may have directly offset firm load shed. In looking at the graph, it is obvious that the benefit of reducing EUE is minor compared to the reduction in other costs as we have stated previously. The cost of EUE could vary greatly and have very little impact on the economics. Reliability at or near a 1-in-10 LOLE target already results in extremely low EUE.

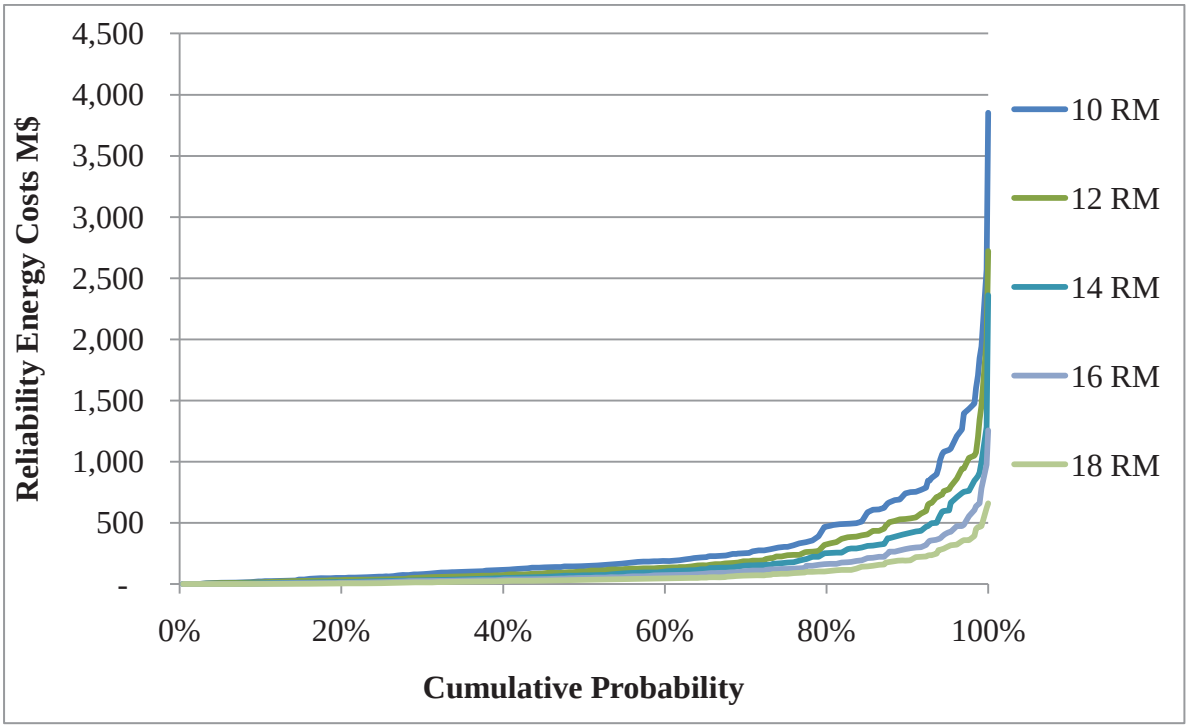
Figure 11. Economic Optimal (Risk Neutral) Reserve Margin[49]



Based on Figure 11, the minimum total system costs to customers is met at a reserve margin of 13%. The figure represents all system costs above the dispatch of a CT plus the cost of unserved energy plus the additional carrying cost of CT capacity over a range of reserve margins. It should be noted how flat the curve is between 12% and 15%. This says that there is some room to move within this range and not be penalized substantially by additional costs. Because this figure represents the average of 1000's of iterations (combinations of weather, load uncertainty, and unit performance), it hides the fact that individual years can be drastically different from the average. This economic target reserve margin doesn't put any additional emphasis on the extreme high cost outcomes, and is therefore defined as the risk neutral target reserve margin. When adding capacity in a regulated, vertically integrated market, the fixed costs are reasonably static whether procured through a PPA or through direct ownership by a utility. Based on detailed engineering estimates of the installed cost of CT capacity, resource planners can be fairly confident in the cost of capacity. In our example, 300 MW will cost approximately $30M per year. However, the incremental capacity may provide less than $1M in benefit in mild weather years during recessions or it may provide >$400M in value in years with extreme weather or unexpected load growth. Figure 12 shows the entire distribution of system energy costs (all production costs and purchase costs above the dispatch cost of a CT plus the cost of societal unserved energy) across different reserve margin levels. The high cost scenarios at the right hand of the chart represent the severe scenarios of extreme weather and under forecast of load.

[49] This figure represents customer system costs for a vertically integrated utility. Structured markets are discussed in later sections.

Figure 12. Distribution of System Energy Costs



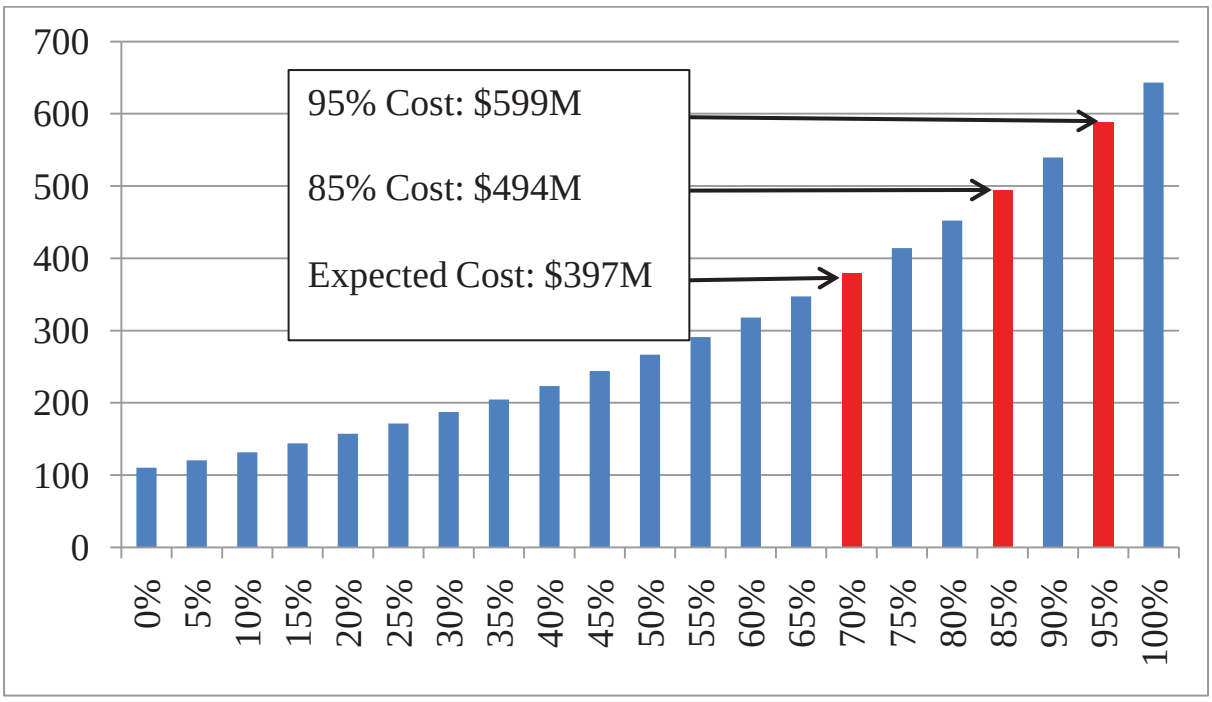
C. Risk Adjusted Reserve Margins

To make the trade-off between volatile reliability energy costs (production costs above CTs, purchases above CTs, and EUE costs) and static fixed costs (carrying cost of capacity), a risk adjustment is likely justified to the risk neutral optimum reserve margin. In the same way that a homeowner is willing to pay $1000/year to insure his $100,000 house against loss even though the probability of loss is far less than 1%, load serving entities are likely willing to pay a fixed payment toward installed capacity to insure against an extreme scenarios shown on the previous figure, even if the fixed payment is slightly higher than the average economic benefit. But how much more in fixed costs should customers, planners, and regulators be willing to pay above the amount that is justified by the risk neutral optimum reserve margin?

Traditional risk metrics in the electric power industry include Value at Risk (VaR), Coefficient of Variation, and mean-variance frontiers. Value at Risk is a quantitative measurement of the amount of exposure at various confidence levels within a specific time interval. Coefficient of Variation and Mean-Variance Frontiers are comparisons of variation across various portfolios and planners utilize them to minimize variance in an economically competitive portfolio.

While the conventional definition of VaR is the risk of loss on a specific portfolio of financial assets, it is used in this example as the risk of additional costs above expected costs. The distribution of total production costs above the dispatch cost of a CT plus marginal CT carrying costs for the 13% reserve margin case is shown in Figure 13. The expected cost for this case is $397M. Eighty-five percent of all scenarios in this case have total costs of $494M or less and 95% have total costs below $599M.

Figure 13. Distribution of Total Costs (Production Costs and Purchases Costs Above a CT + CT Carrying Costs + Cost of Unserved Energy) at 13% Reserve Margin



Typically firms will evaluate VaR at 85%, 90%, or 95%. The distributions for each reserve margin in the chart above allow us to calculate the approximate VaR over a 5-year period for the entire range of possible scenarios. Subtracting the total system cost from the average system cost produces the VaR at the respective confidence level. The VaR at 85% is $494M - $397M = $97M. This means that in 85% of all weather scenarios and economic growth scenarios, total costs should not be more than $97M above the expected costs. The table below, Table 6, summarizes VaR at a range of confidence levels for each of several different possible reserve margin targets including the 13% reserve margin example presented in Figure 13 above.

Table 6. Risk Analysis

		Risks Above Expected Costs		
Reserve Margin	Total Expected Costs	VaR 85	VaR 90	VaR 95
%	M$	M$	M$	M$
10%	409.3	145.3	208.4	321.2
11%	402.5	128.2	182.9	277.6
12%	398.5	112.2	159.2	237.8
13%	397.4	97.2	137.2	201.7
14%	399.0	83.3	117.0	169.3
15%	403.4	70.5	98.5	140.7
16%	410.7	58.7	81.8	115.8
17%	420.7	47.9	66.8	94.6
18%	433.5	38.3	53.5	77.1
19%	449.2	29.7	42.0	63.3

As an example from the previous table, moving from 13% reserve margin (economic risk neutral reserve margin) to a 15% reserve margin reduces Var 95 (a measure of the risk above the expected case) from $201.7M to $140.7M while the change in expected system costs from 13% to 15% is only a $6M increase (as seen previouslyin Figure 11). Targeting a 15% reserve margin results in slightly higher costs than the minimum cost reserve margin, but provides substantial risk mitigation from a single utility perspective. The determination of an economic optimal risk adjusted reserve margin which represents the ideal tradeoff in risk and cost will depend on the risk appetite of the decision makers at the respective utility or regulatory body.

D. STRUCTURED MARKETS: THE CONSUMER PERSPECTIVE

Economic reserve margin planning is contingent on market structure. In a vertically integrated utility environment with rate based assets, adding capacity only affects the cost of serving load that would have otherwise been met by resources with dispatch costs above the dispatch cost of that incremental resource. For example, imagine a utility which had no neighbors. The cost of serving load is only the physical production costs (fuel and variable O&M costs) of generating electricity to meet those loads. If this utility would typically dispatch oil turbines at loads above 30,000 MW at a cost of $300/MWh, the benefit of replacing the oil fleet with efficient gas turbines (with dispatch costs of $100/MWh) would only be the production cost savings ($200/MWh). In this example, if the oil fleet previously

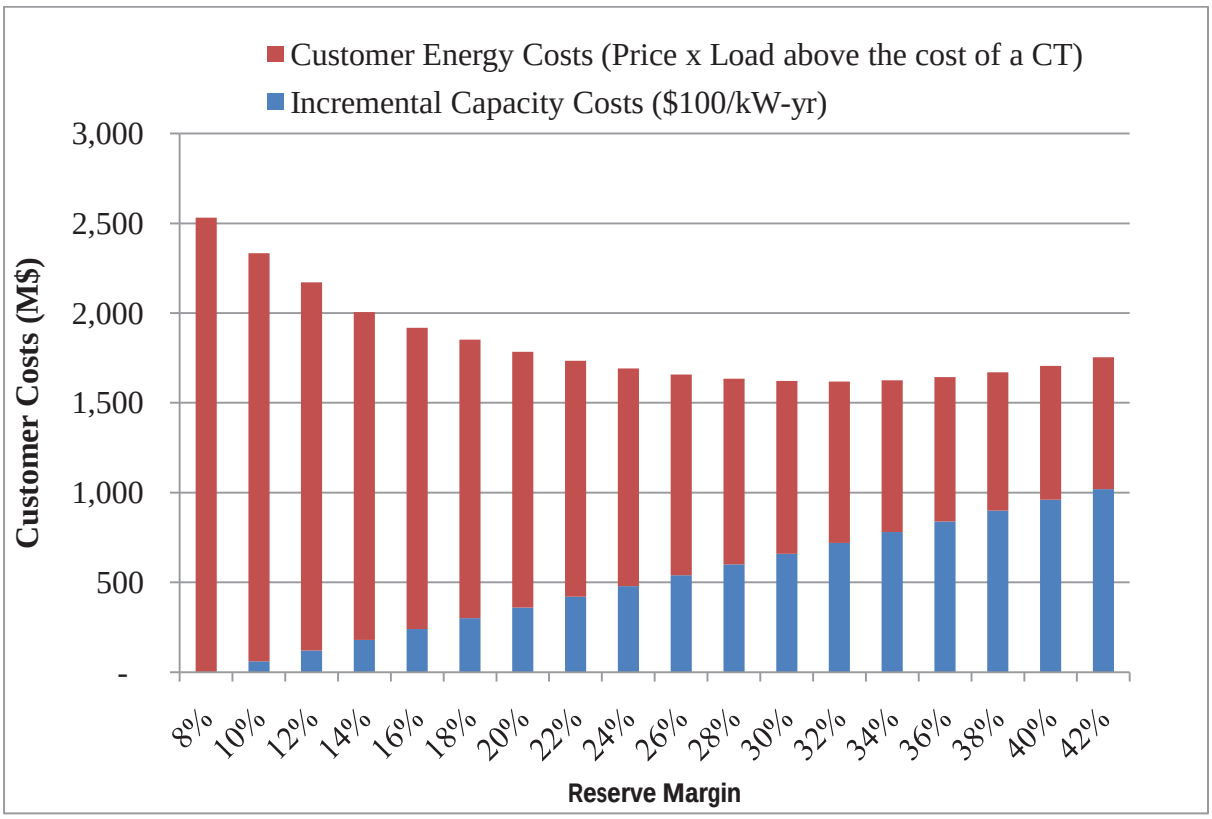
ran 100 hours per year, the benefit would only be $20/kW-yr[50], not nearly enough to justify replacing the oil capacity.

However, under another market construct, the economic decision analysis would be very different. Imagine a wholly competitive energy market where all load serving entities are completely independent from generating companies. The load serving entity is forced to buy all its energy from the energy market at the market clearing price. Generators get paid based on which unit in the marketplace was on the margin, or which was the highest cost unit to be dispatched. For the owners of base load resources, having high cost oil generators on the system and in the dispatch for 100 hours per year could be a boon. Whenever a high cost unit is on the margin, each and every generator will be paid the dispatch cost of that unit, which in this example is $300/MWh. If the system averaged 30,000 MW in load per hour, generators would receive $900M[51] in aggregate over these hours. If the average production cost of those units was $30/MWh, 90% of the revenue is operating profit. If the oil fleet was 1,000 MW in size, suppose replacing it with efficient gas turbines lowers the marginal cost in these hours to $60/MWh. Now, the net revenue to all generators would only be $180M[52] for these hours. The reduction in revenue of $720M for generators is a direct benefit to consumers. In fact, since adding 1,000 MW of efficient CT lowered costs by $720M per year, consumers would be getting $720/kW-yr of benefit from capacity that should cost no more than $100/kW-yr. However, base-load generators, that would no longer be receiving those revenues, may be dependent on this revenue to cover fixed costs. Any approach to identifying the ideal reserve margin target should consider both the generator and consumer's perspectives for the market structure being examined.

First, let us further consider the benefits of increased reserve margins to consumers in an energy only market structure. Using the same case study simulations, if we were to compare the energy market costs (assuming customers pay for their entire load at the market clearing prices) as seen below in Figure 14 to a proxy for incremental capacity costs, then the cost/benefit analysis could support reserve margins above 30% meaning there are still energy market savings greater than the incremental capacity costs at these reserve margin levels. The difference between this analysis and the results seen in the single regulated utility example previously shown in Figure 11 is due to the fact that load serving entities (customers) are paying the high spot prices for all load (30,000 MW) in a given hour versus only paying expensive prices for the high cost resources on the margin which may only be a couple hundred MWs of load.

[50] $200/MWh * 100 hr/year = $20/kW-yr
[51] $30,000 MW * $300/MWh * 100 hrs = $900 M
[52] $30,000 MW * $60/MWh * 100 hrs = $180 M

Figure 14. Illustration of Economic Target for a Load Serving Entity That Relies 100% on the Energy Market



This is a purely hypothetical exercise however. Setting a reserve margin target based on these customer savings is not feasible or desirable in current structured markets for several reasons. First of all, in energy only markets the incremental capacity costs shown in Figure 14 are not paid by consumers so the consumers would always benefit from higher reserve margins while energy margins for generators continually decrease. In structured markets that have forward capacity markets, all generators are paid the same capacity price. In the above example, only the incremental capacity costs were assumed to illustrate the comparison to the vertically integrated utility analysis in Figure 11. In addition, load serving entities in current RTOs often self supply or enter into bilateral agreements to cover a substantial portion of their load and balance the remainder of their load using the energy market. Under this scenario, the savings to customers would be greatly reduced and would more likely resemble the optimal reserve margin methodology that was shown previously in Figure 11. While the idea that a reserve margin well above 20% is ideal for consumers fully exposed to the energy market may be counterintuitive, it is simple to demonstrate. In PJM in 2010, reserve margins were well above 20%[53], but there were still 81 hours with energy prices more than $100/MWh higher than the dispatch cost of a CT. The load in these hours for the PJM_ROM region averaged 33,000 MW, so the total cost of energy above the cost of CTs was greater than $264M[54]. If an additional 1,100 MW of combustion turbines had been present,

[53] *2011 Long-Term Reliability Assessment,* retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdfNERC LTRA

[54] 33,000 MW * 80 hours * $100/MWh = $264 M

presumably the costs above CTs would have been negligible[55]. This suggests that 1,100 MW of CTs can save $264M in one year compared to the carrying cost of that capacity at only $110M[56] per year. This lends some credence to our theory that consumers exposed to the energy markets can receive substantial benefits with new resources even at high reserves margins.

In the same region, however, energy margins for CTs were only ~$50/kW-yr. So CTs were not getting full cost recovery from the energy market, and yet consumers would have benefitted from substantially more capacity.

E. Structured Markets: The Generator Perspective And The Missing Money Problem

Wholesale peaking generators have not been able to recover their fixed carrying costs in the past decade from energy markets. Even in regions with capacity markets which pay supplemental revenues to generators, without long-term bilateral agreements, CTs have been unable to cover costs[57].

But how critical of an issue is this? Economic optimal reserve margins for energy only markets are defined as the point at which marginal capacity can earn enough revenues to cover fixed costs. How far from this economic target are most structured markets today? CT energy margins are the summation of all the hourly market prices above the dispatch cost of a CT for a given year. As shown in Table 7, which presents the perspective of a merchant generator in such a market, CT energy margins and the frequency of prices above the dispatch cost of an efficient CT decrease as additional CTs are added to a system. These energy margins represent the weighted average energy margins in the Base Case simulations. Recall that the 1-in-10 LOLE based reserve margin was at 9.75% and the economic optimal reserve margin based on a single regulated utility was 13% (See Figure 11). The CT only receives $86/kW-yr at a 9.75% reserve margin and $73/kW-yr at a 13% reserve margin which is used to go towards covering its fixed costs of $100/kW-yr. The energy only economic optimal target reserve margin for this region is 7% because that is the point where a CT fully recovers its fixed costs.

Table 7. Merchant Generator Perspective

Reserve Margin	8%	10%	12%	14%	16%	18%
Expected CT Energy Margins ($/kW-yr)	$ 94.75	$ 85.63	$ 77.58	$ 70.57	$ 64.62	$ 59.72
CT Hours of Operation	1,211	1,104	1,007	978	926	897

How is it possible then that generators are only able to recover their fixed costs at a 7% reserve margin, but consumers of a vertically integrated utility have financial benefit to having reserve margins at 13%? In many hours in the simulations, the study region is

[55] Load in these hours was 1,100 MW higher than in hours with prices equal to the dispatch cost of a CT, suggesting the addition of 1,100 MW of efficient CTs would bring the high prices down close to the cost of a CT.

[56] 1,100 MW * $100/kW-yr = $110 M

[57] PJM, State of Market Report, 2010, Vol. 2, p. 33

purchasing power from outside regions. Take an example hour in which the region is purchasing 2,000 MW at $200/MWh. The addition of 500 MW of resources to the study region does more than just avoid purchase costs of 500 MW at $200/MWh. It actually brings down the cost of the remaining 1,500 MW that needed to be purchased. When the study region was originally purchasing power from the outside region, the clearing price was based on the unit that was on the margin in the outside region. In order for the study region to buy 2,000 MW, the outside region had to dispatch progressively higher cost resources. Since in the change case in which the study region added 500 MW of capacity, only 1500 MW needed to be purchased, the clearing price for the purchase will be lower (for this example assume purchase cost dropped to $150/MWh). So the addition of the resource provided $140/MWh of benefits for the 500 MWh of purchases it avoided[58]. It also achieved $50/MWh benefit for the 1,500MWh of purchases that were still made. The total benefit in this hour is $145,000[59] or $290 for each MWh of energy provided by the new resource[60]. So the benefit to the customer is higher than the revenues that might be seen by the new generator. This disconnect between the consumer perspective and the generator perspective was partially explained above, but there are additional reasons that generators have a difficult time recovering costs in many structured markets today.

1. Price Caps

Many regions have regulatory caps on bid prices at ranges between $1,000/MWh to $3,000/MWh. As discussed, this is less than VOLL and from a theoretical perspective suggests that consumers are not paying enough for resource adequacy. However, there is a reserve margin at which peaking generators would cover the cost regardless of where the price cap was set. If generators could achieve full cost recovery at an 11% reserve margin with no price caps, then generators should be able to achieve full cost recovery at perhaps an 8% reserve margin if there was a $1,000/MWh price cap. The point being that if the maximum price is lower than VOLL, generators should build less capacity such that high prices (but less than $1,000/MWh) are hit more frequently. Price caps are frequently cited as the primary reason for "missing money"[61], yet the authors believe this is a small component of the overall market design problems.

2. Physical Reliability Targets

ERCOT is one of few energy-only markets in North America. As an energy only market, there is no explicit reserve margin target. However, ERCOT performs an LOLE study periodically which communicates to the system the reserve margin which would achieve 0.1 LOLE. While not a target, several of the LSEs in ERCOT may use that reserve margin for their own generation planning and either build or contract to maintain at least that level of reserves. The potential result of individual LSEs planning to the 0.1 LOLE reserve margin is that the aggregate system reserve margin may be equal to or higher than the 0.1 LOLE reserve margin. If a region consisted of 10 LSEs, all of which planned to the same reserve margin independently, the aggregate reserve margin would be higher since there is diversity between disparate loads. But regardless of how a region

[58] The load serving entity paid the $60/MWh dispatch price of the resource instead of the $200/MWh market price

[59] (140 * 500 + 50 * 1,500) = $145,000

[60] $145,000 / 500 MWh = $290/MWh

[61] Hogan, William (2005), "On an "Energy Only" Electricity Market Design for Resource Adequacy."

ends up with a reserve margin that is equal to or higher than the 0.1 LOLE, the impact on CT energy margins is typically negative. As shown in our simulations, the expected CT energy margin at a 0.1 LOLE reserve margin is less than the carrying cost of capacity even with no energy price caps. To clarify the theoretical reason for this disparity, an illustration will be helpful.

Imagine that regions planned to a reliability target of one event in 10,000 years. To achieve this lofty goal, reserve margins may need to be at 30%. With a 30% reserve margin, there would be very few, if any, hours with energy costs much above the dispatch cost of CTs. Unlimited price caps would make no difference since there would almost always be additional capacity available to prevent scarcity prices. So if load serving entities or a portion of the load serving entities in a region plan to an LOLE target, it is possible that system reserve margins may be higher than the levels at which generators would receive cost recovery.

3. Economic Growth Slowdown

Since 2000, the US economy has consistently grown at slower rates each year than was expected 4 years prior.[62] When the economy grows slower than expected, load grows slower than expected. Since generation expansion is planned years in advance, new generation has come online while the load it was meant to serve has not materialized. An example utility may have expected 1,000 MW of load to appear due to a growing economy and so built new generation. However, much of that load did not appear over the past 10 years and so reserve margins rose. With reserve margins not only above the level which would achieve cost recovery for efficient CTs, but also above 0.1 LOLE based reserve margins which typically result in low CT energy margins, returns for peaking generation have been consistently small. Presumably, at some point the economy will begin to grow faster than economists expect and load growth may outstrip resource additions, resulting in lower reserve margins and higher returns for peaking generators. However, as discussed in other sections, reserves would need to drop substantially in order for this to occur.

To be clear, this issue is different from the issue related to the use of physical reliability metrics in setting reserve margin targets. Even if the economy was experiencing robust growth, the use of physical reliability metrics could still negatively affect the energy revenues generators could expect. Slow economic growth simply adds to the disparity produced by high reserve margin targets since realized reserve margins end up being even higher than the high reserve margin targets when the economy grows slowly.

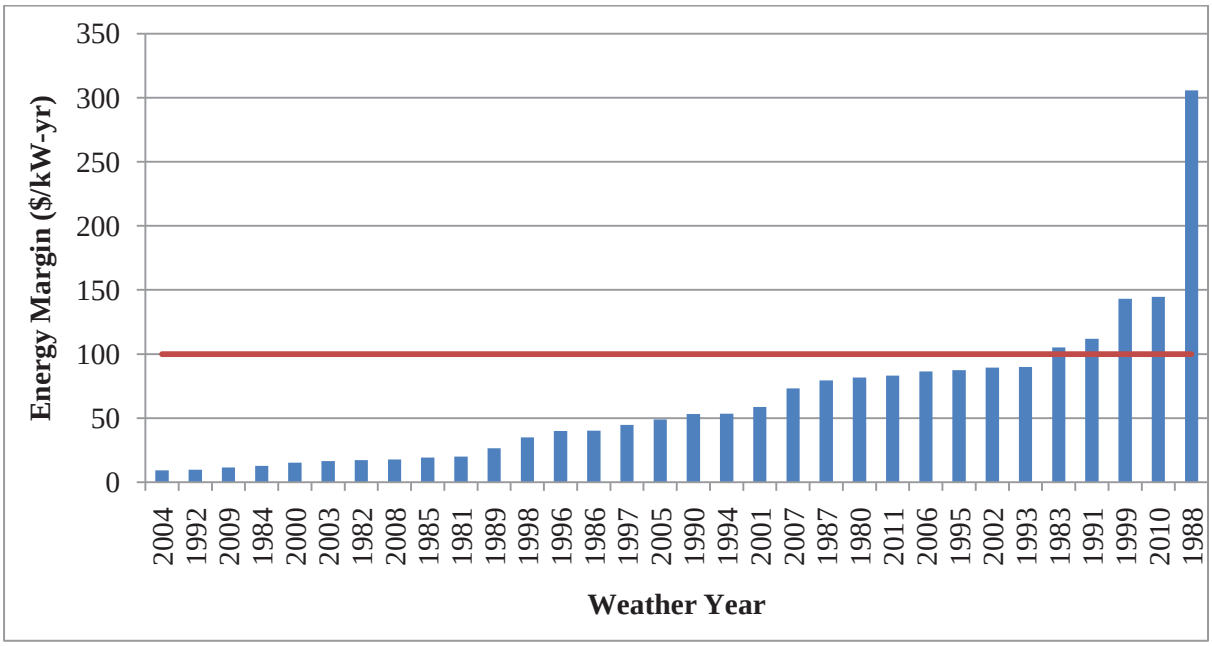
4. Weather Volatility

Even with a regulatory-enforced scarcity pricing curve designed to achieve full cost recovery for peaking generators, differences in weather patterns mean that many years energy prices would be lower than needed for generators to recover costs. Figure 15 shows results from the Base Case simulations for the study region. In a small number of possible weather years, returns would far exceed the necessary levels to cover carrying costs. However, in a large percentage of years, revenues would be far less than necessary. This is not a feasible market space for many developers who rely on debt to

[62] See CBO forecast for 2000-2013

finance the construction of their facilities. If a generator cannot demonstrate its ability to cover specific debt service ratios each year, it will not be eligible for debt financing.

Figure 15. CT Energy Margins by Weather Year



5. Generator Market Forecasting

The authors will not venture to guess the skill level of generators determining when markets will be in equilibrium such that new generation can cover fixed costs. However, this task is quite difficult, so expectations of their accuracy should be quite low. This analysis must typically be performed 5 years in advance of the new generation coming online and take into account dozens of variables including load growth rates, fuel costs, market interaction, regulatory intervention, scarcity pricing, emission prices, resource mix changes, demand response impacts, and bidding strategies.

In summary, each of the components mentioned above contribute to the missing money problem. It is not an isolated issue simply due to a single design flaw as frequently cited. Since generators in energy only markets prefer low reserve margins to achieve cost recovery what is the best way to incentivize generator investment to achieve 1-in-10 LOLE and/or achieve a higher reserve margin that is more economic for consumers. Forward capacity markets have been designed in many of the existing structured markets to alleviate this disconnect. In this capacity market design, all generators are provided additional capacity payments to allow new generators to recover fixed costs at a reserve margin that meets 1-in-10 LOLE standard. The setback to this approach is that while consumer energy costs are reduced at the 1-in-10 LOLE level, the fact that capacity payments are paid to all capacity forces total customer costs to be higher than if reserve margins remained at the lower energy only economic reserve margin target. This is further illustrated in the next section. Another method used to solve this problem is to force load serving entities to enter into bilateral contracts up to a specified reserve margin. This method is used in the California ISO (CAISO) today. One advantage of this method is that it allows generators to enter into long term contracts which provide revenue stability versus a forward capacity market which only provides revenue in the short term. It also allows load serving entities to make decisions on capacity based on long term cost projections.

F. SUMMARY RESULTS FOR DIFFERENT MARKET CONSTRUCTS

Table 8 summarizes the findings of the base case results from the perspective of a single vertically integrated regulated utility, energy only market, and energy plus forward capacity market. Table 8 shows that the economic optimal reserve margin for the regulated utility is 13% based on the consumer's total system cost perspective as defined in Section A of this Chapter . This target resides several percentage points above the 1-in-10 LOLE based 9.75% reserve margin. The reserve margin target for the energy only market is 7% based on the level of reserves at which a new CT will recover its costs. Under an energy only construct, consumers would benefit from higher reserve margins but energy margins are lower than the minimum required to sustain the higher reserve margin. For the energy plus forward capacity market construct, the target reserve margin is assumed to be based on 1-in-10 LOLE[63] which is 9.75% and it is assumed that the capacity payment paid to all generators at this level is enough that when combined with energy margins a CT will recover its fixed costs.

From a total system costs perspective, the regulated utility provides the lowest cost at its target reserve margin. It should be noted that the results for each construct were developed from the same simulations meaning there were no benefits recognized from a more coordinated economic dispatch that an RTO/ISO would provide. The energy only construct's total costs at a 13% reserve margin are much lower per year, but in theory this reserve margin would not materialize because generators would not recover their fixed costs at this level. The energy plus capacity market construct produces higher costs as reserve margins increase from the 7% energy only economic target because the additional capacity payments are made to all generators. If targeting 1-in-10 LOLE, the total costs including a capacity payment that made generators whole is $7.925 B as shown in the table. It should be noted that there is also some risk benefit seen with the structures that result in higher reserve margin targets because the volatility related to energy costs decreases as reserve margins increase.

Assuming idealized resource mixes and purely competitive or efficiently regulated markets, the cost comparison below illustrates how the structure that results in the lowest reserve margin does not necessarily produce the lowest system cost.[64]

Table 8. Total System Costs at Target Reserve Margin Levels

	Target Reserve Margin	Total System Costs at Target (Billion $)
Regulated Utility	13.00%	$7.805
Energy Only Market	7.00%	$7.860
Energy plus Capacity Market	9.75%	$7.925

To be clear, the point of this table is not to state that the regulated utility environment is the optimal structure. Energy only and energy plus capacity markets offer a number of attributes such as fostering competition and diverse resources that may result in lower total system costs for customers. This table just highlights that market structure can have a

[63] Forward capacity markets in the Eastern Interconnection currently base targets on 1-in-10 reliability metrics. These include PJM, NY-ISO, and ISO-NE.

[64] These total system costs include all capacity costs and energy costs (not just costs above the dispatch costs of a CT) to meet load as well as the societal costs of unserved energy.

significant impact on both reliability and total system costs and should be considered when performing resource adequacy planning.

G. Selection of Marginal Resource in Economic Reserve Planning

It is important to remember that the identification of a target reserve margin based on economics is contingent on the marginal resource used to vary reserve margins. A single point estimate of the ideal reserve margin assumes that all capacity should be treated as equal. In reality, economic resource adequacy planning must consider the implications for all types of resources that may provide resource adequacy. The economic trade-off analysis is highly dependent on the characteristics of the capacity being added. All capacity is not equal. Adding demand response capacity will not provide as much economic benefit since it is not dispatched until prices are much higher or reliability is a more pressing concern. In generic SERVM modeling runs, the average market price when CTs are dispatched is ~$70/MWh. The average market price when demand response is called may be $500/MWH+. This indicates that the system costs between reserve margins will be drastically different if CTs are the marginal unit type vs. demand responses resources. The carrying costs are also different between the resource types. Also, the incremental decision may not be the addition of a new resource; it may be the retirement of an old high-cost resource. While 1-in-10 LOLE is an attractive metric because of its simplicity, the reserve margin determined through this method treats all capacity the same. If a resource can keep the lights on as effectively as a combustion turbine, the different product characteristics are immaterial. But the metric doesn't provide guidance to what type of resources should be used to meet peak requirements and leads to many uneconomic resource procurements. Resource planning is unfortunately a complicated process that requires the assessment of both the economic and physical reliability contributions of resources.

VI. IMPACT OF VARYING DEFINITIONS, CALCULATIONS, AND APPLICATIONS OF 1 IN 10 ON ECONOMICS

Based on the research performed in Section III, the majority of entities in the Eastern Interconnection that use a physical metric for setting reserve margin targets use the 1 day in 10 year standard. Of those that use the 1 day in 10 year standard, all but one use an identical definition for the metric. SPP is the only entity that uses a different definition. SPP assumes 2.4 LOLH versus the standard 1 event in 10 years (0.1 LOLE). The latter is more stringent and leads to a higher reserve margin level. In this study, using the 2.4 LOLH definition typically results in a reserve margin 5% lower than the 0.1 LOLE derived reserve margin. However, although SPP measures reliability against the less stringent 2.4 LOLH metric, their reserve margin target is set at a higher level than suggested by the metric, potentially obviating the difference in expected reliability.

As part of this paper, the authors were asked to address how the varying definitions, calculations, and applications of the 1 day in 10 years standard impact the economics of resource adequacy. If regions planned reliability using the lower 2.4 LOLH instead of the 0.1 LOLE, reliability costs would be much higher. The base case simulations indicate reliability costs (excluding capacity costs) at the 0.1 LOLE equal to $290M/yr while the reliability costs at 2.4 LOLH are $450M/yr, a difference of $160M/yr. The 2.4 LOLH scenario has lower capital costs since it has a lower reserve margin, but even after adjusting for capital cost savings, the less stringent 2.4 LOLH developed reserve margin would result in additional total system costs of $40M/yr compared to planning using the 0.1 LOLE definition. In addition, those numbers do not reflect what would happen if all regions used the lower standard. The base case assumes that other regions still maintain higher reserves, muting the impact of the less stringent standard. If all regions planned using the lower standard, average costs would be expected to be exorbitant. In addition, average economics doesn't adequately consider the risk of high impact scenarios. In cases in which load was much higher than expected or units didn't perform as well as expected, the additional costs of only maintaining reserves to meet the 2.4 LOLH on average could be in the billions of dollars. The base case economic simulations indicated that the difference in costs for the most extreme case if planning to 0.1 LOLE versus planning to 2.4 LOLH could be greater than $2B for a single year.

For a small region with few interconnections, the 0.1 LOLE and the 2.4 LOLH based reserve margins could potentially both be higher than the optimal economic reserve margin, but in general, the base case simulations demonstrate that using the 2.4 LOLH definition likely results in a more risky and high cost system if modeled accurately. Compared to the 0.1 LOLE, the economic optimum reserve margin could be higher or lower depending on a number of system attributes including system size, market structure, neighbor assistance availability, and transmission availability. And depending on assumptions such as how emergency operating procedures will be employed and how capacity is counted, the comparison is further complicated.

The sensitivities presented in the next section show how some of these assumptions drive the 1-in-10 LOLE target and the economics of resource adequacy. Based on our past experience, the 1-in-10 LOLE target is more sensitive to these assumptions than a methodology that uses an economic framework. An LOLE method can be driven by one event or one peak hour while the economics that measure more than the cost of firm load shed are impacted by many more hours across the year and are therefore less sensitive. From our perspective, it is critical for regulators and planners to know if its target reserve margin is economic.

VII. IMPACT OF INTERCONNECTED MARKETS AND BROAD PLANNING ON RESOURCE ADEQUACY AND 1 IN 10 CALCULATIONS

Astrape performed several sensitivities around the regulated utility base case to show the impact that interconnected markets and inter-regional commerce have on the resource adequacy of the region being studied. If markets are highly interconnected and well coordinated among regions, then resource adequacy targets could be lowered. In the base case, there is substantial transmission capability between the study region (PJM_ROM) and surrounding neighbors. In fact, the limit to and from PJM_E and PJM_R_RTO is virtually unlimited as the 8,000 MW transfer capability is rarely fully utilized. With these limits, it is likely that the constraint is capacity on the other side of the interface rather than the transmission capability.

A. ISLAND SENSITIVITY

The first sensitivity that was simulated treated PJM_ROM as an island. This sensitivity is purely academic since it in no way represents reality. When the case is simulated, the region would need to carry an 18% reserve margin to meet the 1-in-10 LOLE standard. This compares to a 9.75% reserve margin to meet the same criteria in the base case. Given these results, it could be stated that surrounding regions via load diversity and generator diversity provide approximately 8% of reserves for the PJM_ROM region. For this sensitivity, economics were not evaluated.

B. ALLOW NEIGHBORING REGIONS TO DISPATCH DEMAND RESPONSE IN ORDER TO ASSIST NEIGHBORING REGIONS

The next sensitivity was designed to understand the impact of allowing regions to dispatch demand response resources in order to assist another region. The typical approach to demand response is to only call on it during emergency conditions. In actual practice, it is unlikely that one region would dispatch emergency demand resources in order to be able to sell generation to other regions. However, there is a range of types of demand response, some of which may self-dispatch at lower prices or may have substantial availability. These resources may be dispatched more frequently and may possibly be used in a way that allows one region to sell to other regions. The base case did not allow these resources to be called in order to free up other capacity to be sold to neighbors. The change case was to eliminate this constraint. If one region was able to meet firm load obligations and operating reserve requirements in an hour, and had additional demand response capacity, SERVM was configured to allow the demand response resource to dispatch and sell energy to another region. In this change case, the reserve margin needed to maintain 0.1 LOLE shifted from 9.75% to less than 7%. The economic optimum shifted from 13% to approximately 12%. This change in emergency dispatch affects the 0.1 LOLE based reserve margin more than the economic reserve margin because LOLE is more sensitive to what occurs in these peak hours.

C. OPERATING RESERVE SENSITIVITY

For the base case simulations, all regions were given a 2% spinning reserve requirement and a 4% total operating reserve requirement. Firm load shed occurred if operating reserves dropped below the 2% spinning reserve requirement. In this sensitivity, the spinning reserve requirement was allowed to be completely depleted before shedding firm load. As expected, the results of the sensitivity showed that both the 1-in-10 LOLE target and economic target dropped by 2%.

D. System Equivalent Forced Outage Rate (EFOR) Sensitivity

The Equivalent Forced Outage Rate (EFOR) is the average percentage of capacity unavailable when needed. The 1-in-10 LOLE target and the economic optimal target both shifted with a 1 to 1 ratio as system EFOR shifted. In other words, when system EFOR for the region was increased by 3%[65], the 1-in-10 LOLE target shifted from 9.75% to 12.75% and the economic target shifted from 13% to 16%.

E. Remove all Load Diversity Among Neighbors

If load diversity is removed completely and all regions reached peak load at the same time, then the target to meet a 1-in-10 LOLE standard shifts from 9.75% to 15.5%. The economic target shifts from 13% to 18%. The impact during peak hours impacts LOLE slightly more than it impacts the economic target.

F. Transmission Sensitivities

Two sensitivities were performed for transmission. In the first, all transfer capabilities between regions were reduced by 50%. In the second a distribution was used for each interface representing the availability of the interface. The distribution for this sensitivity is shown in Figure 16. By using this distribution, the range of transmission availability can be captured from 0% to 100%.

Figure 16. Distribution of Transmission Availability

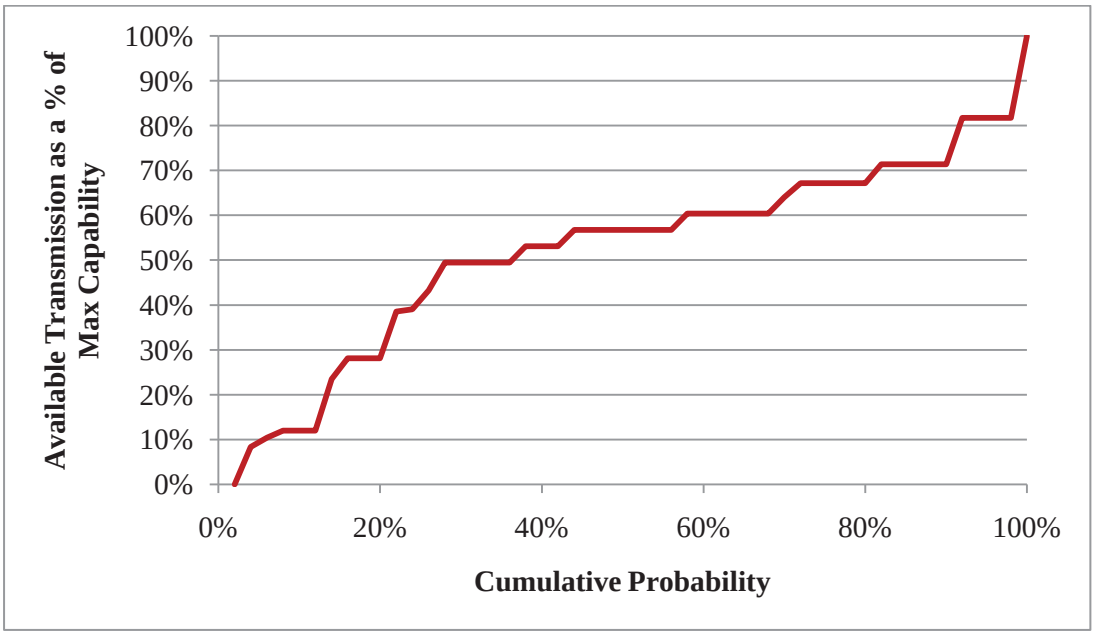


Table 9 shows the results of the two sensitivities. Using the distribution shown above in Figure 16 impacts both the 1-in-10 LOLE and economic optimal reserve margin more than just reducing the capability by 50%. This is logical because the distribution is more stringent in that there are hours where no transfers will be allowed to occur. Because the region being studied has substantial oil resources in its mix, it is purchasing a substantial amount of energy for economic reasons. When transmission is limited, these purchases decrease and the

[65] The starting system EFOR of 5% was increased to 8%.

optimal reserve margin level increases considerably. Accurately capturing the import capability of a region has a high significant impact on results.

Table 9. Transmission Sensitivities

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours Per Year at 10% RM
Base Case	9.75%	13.00%	4.5
50% Transmission Capability	11.75%	17.00%	15
Transmission Distribution	14.00%	20.00%	13

Since the base case uses static high transfer limits, the base case results are likely too optimistic for both the economic optimal reserve margin and the 1-in-10 LOLE reserve margin. Using refined transfer limits would likely show that for the targeted region, the optimum economic and 1-in-10 LOLE reserve margins would be several percentage points higher. The table above indicates a reasonable upper limit for where these values could fall.

G. EXPANDING TOPOLOGY

A sensitivity was performed to understand how expanding the overall topology would impact the optimal reserve margin for PJM_ROM. For the sensitivity, SOCO and NE-ISO were added to the topology. By adding two additional regions, the LOLE target shifted from 9.75% to 9.25% and the economic target shifted from 13% to 12.5%. Even though PJM-ROM is not directly connected to either region, the dynamic market clearing resulted in more efficient dispatch and the additional regions provide extra load and generator diversity. This indicates that modeling the entire Eastern Interconnection could result in lower targets than indicated by the base case results.

H. SUMMARY

A summary of these results for both the base case and numerous sensitivity cases is shown in Table 10. The overall takeaway is that an optimal level of reserves depends greatly on assumptions made about surrounding interconnections and installed capacity of neighboring regions. These sensitivities also illustrate the need for further analysis in which the full Eastern Interconnection is simulated and appropriate assumptions are verified for a number of these categories.

Table 10. Summary of Analysis Results for Base and Sensitivity Cases

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours Per Year at 10% RM
Base Case	9.75%	13.00%	4.5
Island Case: No Neighbor Assistance	18.00%		21.5
No Weather Diversity Among Neighbors	15.50%	18.00%	9.4
50% Transmission Capability	11.75%	17.00%	15
Transmission Distribution	14.00%	20.00%	13
All Regions Allowed to Share DR Resources	7.00%	12.00%	5
Allowing All Operating Reserves to be Depleted	7.75%	11.00%	4.5
EFOR 3% Increase	12.75%	16.00%	5.9
Expand Topology	9.25%	12.50%	4.25

VIII. ECONOMIC SENSITIVITIES

Sensitivities were performed both on the VOLL and the cost of CT capacity additions. Changing VOLL from $5,000/MWh to $30,000/MWh had no impact on the economic optimal reserve margin. The reason is that the amount of EUE at 13% reserve margin is only ~20MWh and represents reliability above the 1-in-10 LOLE standard. Firm load shed events are not driving the economics to be minimized at a 13% reserve margin. An additional sensitivity analyses varied the cost of CT capacity from $80/kW-yr to $120/kW-yr. Table 11 below shows that the economic optimum is more sensitive to capital costs.

Table 11. Economic Sensitivities

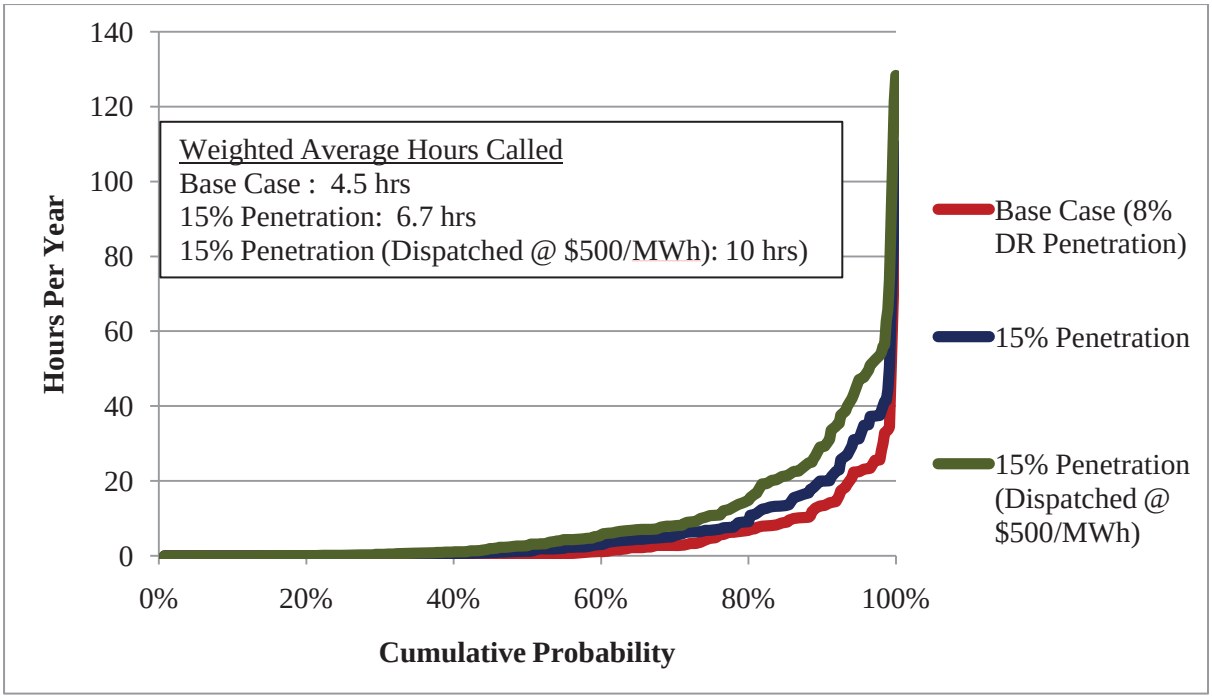
	Economic Optimal Reserve Margin
Base Case: VOLL@15,000/MWh CT Carrying Costs @ $100/kW-yr	13.00%
VOLL @ $5,000/MWh	13.00%
VOLL @ $30,000/MWh	13.00%
CT Carrying Costs @$80/kW-yr	15.25%
CT Carrying Costs @$120/kW-yr	10.25%

IX. RESOURCE MIX SENSITIVITIES AND HOW STATES CAN POSITIVELY INFLUENCE RESOURCE ADEQUACY

A. DEMAND RESPONSE SENSITIVITIES

Demand Response plays a key role in resource adequacy assessments. The key attributes of DR that impacted simulation results are the number of hours the resource can realistically be called in a given year, the point in the dispatch that DR is called, and the percentage of total capacity represented by DR (this percentage is also referred to as the penetration). If DR is called by a utility when prices hit $200/MWh versus $500/MWh, then the resource will provide much more economic value but will obviously need to be available more hours in the year. Figure 17 shows the distribution of expected demand response calls for the base case and two sensitivities with different penetration levels. Recall that the base case assumptions assume that DR is only called after all other options have been exhausted including expensive purchases up to $2,500/MWh and are limited to 150 hours per year. So in the base case, DR is exclusively used for reliability purposes and is always available since its dispatch is so infrequent. Also in the base case, DR provides 8% of the overall capacity mix for the region. The other two curves represent the senstivitiy cases where (1) DR penetration is 15% and resources are called at $2,500/MWh (2) DR penetration is 15% plus resources are called at $500/MWh. Additional sensitivities assuming the resources are called at $200/MWh would show increased frequency of dispatch and the necessary call limits would expand.

Figure 17. DR Call Summary



The next step in the evaluation was to determine how the 1-in-10 LOLE and economic reserve margin would change based on moving from 8% to 15% penetration. Table 12 displays the results. Because the DR was still treated as a reliability-only resource, the physical LOLE metric only shifted slightly and the 1-in-10 LOLE target shifted from 9.75% to 11%. This shows that the 150 hour call limits on the resource were almost enough to maintain the same reliability even with a higher penetration. However, the economic

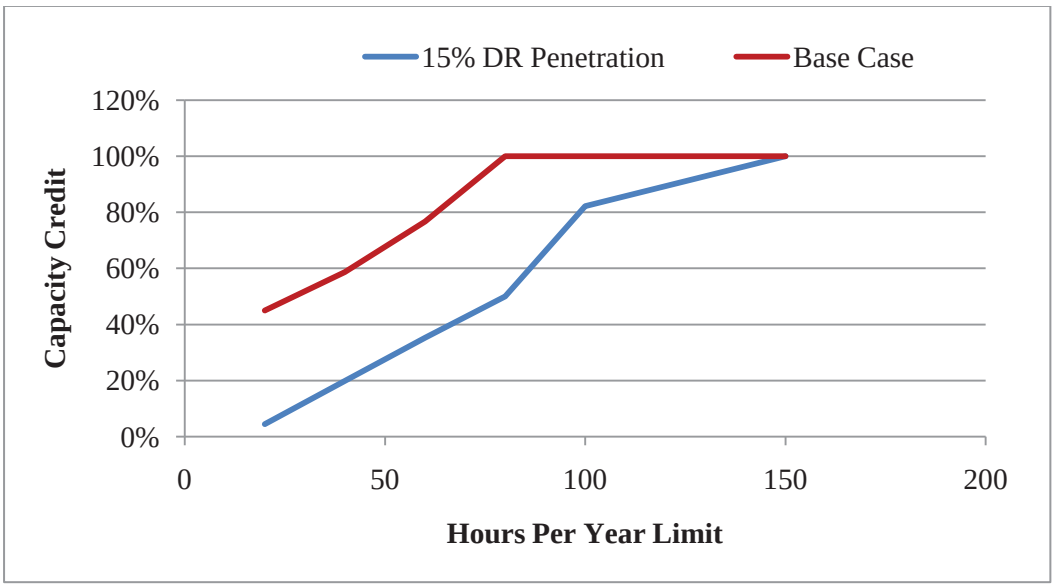
reserve margin was impacted more substantially because when the DR was added, a substantial amount of CT capacity had to be removed from the region to keep the same reserve margin level. Now the region is forced to purchase more energy since several thousand MWs of capacity that was being dispatched at less than $100/MWh was removed. Given this, the economic optimal target moves from 13% to 17%.

Table 12. DR Penetration Sensitivity

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours at 10% RM
Base Case: DR 8% Penetration	9.75%	13.00%	4.5
DR 15% Penetration	11.00%	17.00%	7

The last set of simulations pertaining to DR calculated the capacity credit of the resource assuming different call limits and different penetration levels. For purposes of the analyses, we are defining capacity credit of a resource as the reliability contribution that it provides the system compared to a fully dispatchable resource with 100% availability. So a resource that can only be dispatched 20 hours a year will not provide the same level of reliability as a resource that can be dispatched perfectly for 8,760 hours per year. Figure 18 shows the capacity credit of DR for the base case under different call limits and under a 15% penetration case with the same call limits. The figure shows that in the Base Case (8% penetration level) a 50 hour per year DR resource dispatched for reliability will only provide 63% capacity credit. Under a 15% penetration level, the same resource only provides 28% capacity credit. The higher penetration level would need the capacity more frequently and if it can only be called 50 hours it would be less valuable under that scenario.

Figure 18. DR Capacity Credit



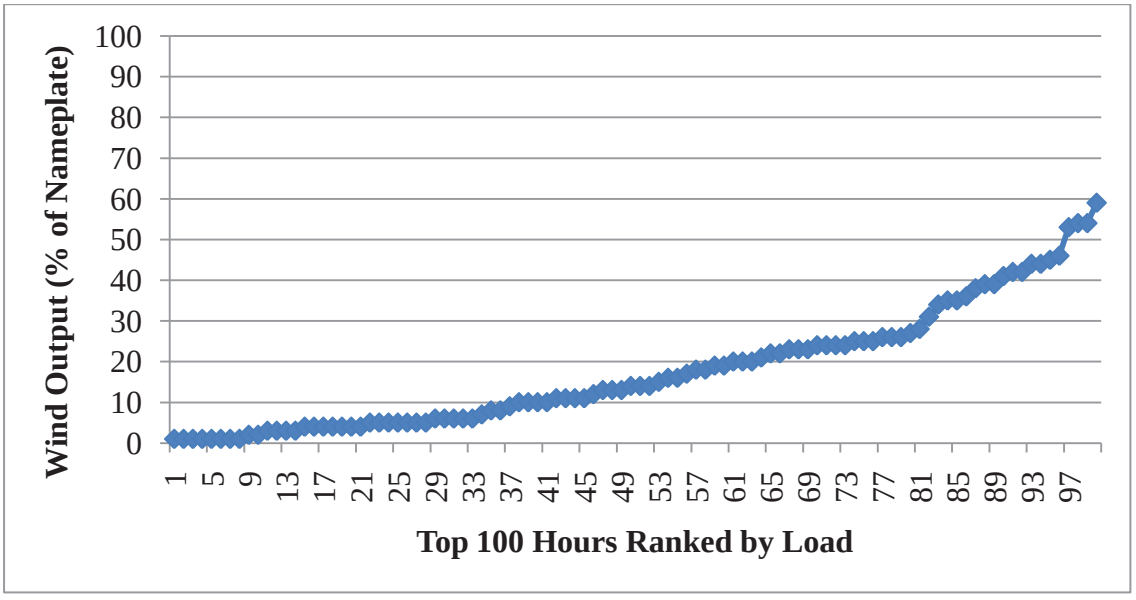
Understanding the risks and benefits offered by DR is critical given the penetration levels that some regions are approaching. Some utilities in Florida are already calculating

"generation only" reserve margins and are considering using such a criterion in their resource planning decisions. This is due, in part, because there is uncertainty on how the DR will perform, including DR participant tolerance levels, as they are called upon more frequently. If states are going to consider further implementation of DR, it is important to ensure that the right amount and type are being added and these resources are being incentivized and valued correctly. States will need to understand all the dynamics and risks that could occur with DR. Some of these have been demonstrated in this case study simulation. Further simulations could assist in understanding this dynamic.

B. Intermittent Resource Sensitivities

Intermittent resources have a fundamentally different resource adequacy profile from conventional resources. The forced outage status of thermal generators is nearly completely independent. Fuel supply, transmission issues, and shared facilities can cause some units to be unavailable simultaneously, but typically outages are independent. Intermittent resources such as wind and solar, however, are dependent on weather conditions which are highly correlated across large geographic areas. For example, with a wind fleet of 1,000 MW in a 50,000 MW system, this does not create significant concern. At a higher penetration of 10,000 MW in a 50,000 MW system, the loss of wind resources will be a more significant issue. Because of wind's intermittency, the capacity value or effective load carrying capability (ELCC) of wind is already much lower than its nameplate capacity. Generally, at low penetration, the ELCC of wind should be close to the average output during peak conditions. If peak load occurs in the summer between 2:00 and 4:00 PM, a rough approximation of wind's ELCC would be the average output during these hours. For many regions, this output is between 15% and 25%. For our studied region, the wind output during the top 100 load hours is shown in Figure 19. The distribution is sorted by wind output and not peak load. The average output of wind is 18% of nameplate rating.

Figure 19. Wind Output During Peak Load Hours

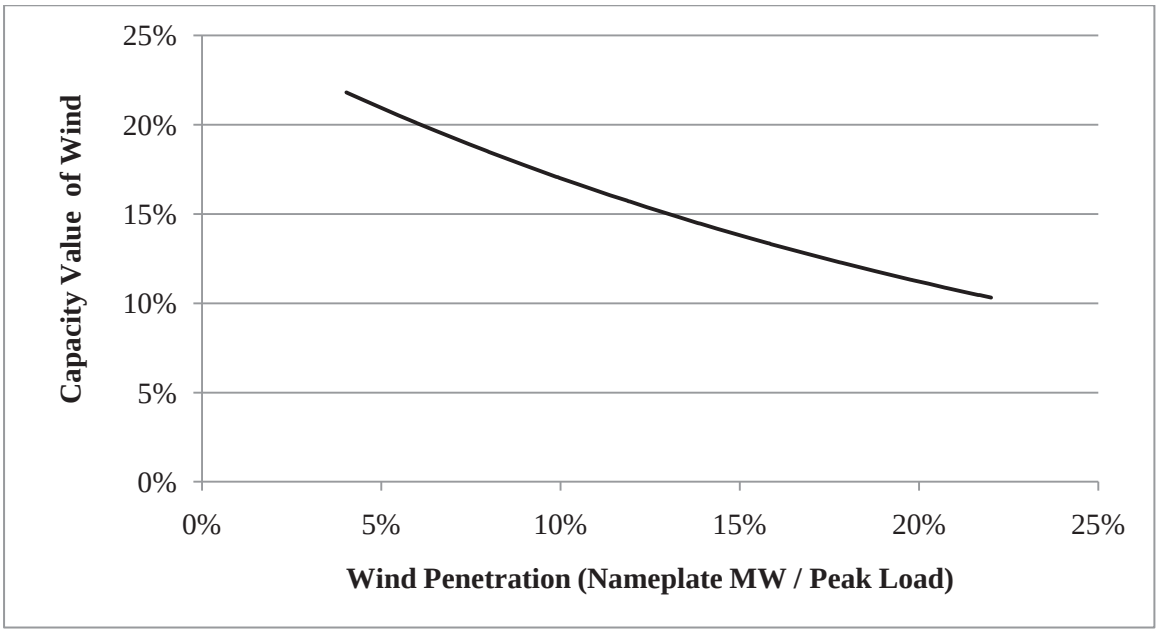


However, this distribution also shows that in some peak hours, the wind output is much less than 18%. At a low penetration of 1,000 MW of nameplate wind, a region giving the wind fleet ELCC credit of 180 MW based on the average output during peak, this is not likely a reliability issue. Getting 180 MW less than expected is not a significant concern. It would be similar to losing a small thermal generator. If the wind fleet is a much larger 10,000 MW,

having an output much smaller than the average output during peak conditions has a much larger impact on the system because it would correlate to losing 1,800 MW of capacity - a much more significant event.

To capture this difference, SERVM was used to determine the ELCC of wind at several penetration levels. When increasing the size of the wind portfolio, the same profile was used for all wind, so the correlation was perfect. This assumption is too conservative, because in reality, as penetration increases, a system would get some diversity benefit. But Figure 20 illustrates that as penetration increases, the capacity value or ELCC drops due to the reasons explained above. At low penetration, the ELCC can be slightly greater than the average output during peak if the system is energy limited rather than capacity limited. Having wind available at other times allows the system to conserve energy limited resources such as demand side resources and pumped storage or other hydro in hours that are lower than the peak so that those resources are available during peak hours. At high penetration, the ELCC is approximately half its value at low penetration.

Figure 20. Wind Penetration Study



These simulations did not capture the impact that intermittent resources has on ancillary service needs. Since the output of wind can vary substantially on a minute to minute basis, additional reserves may be necessary to fully integrate the wind profile. This is potentially an additional impact to reliability and warrants further analysis.

As the penetration of intermittent resources increases, regulators need to be aware of and prepared to address the changing impact these resources have on the economics of resource adequacy and on physical reliability.

C. ENERGY STORAGE SENSITIVITIES

One proposed solution for intermittent resources is often to use energy storage technologies to firm up wind and other intermittent resources. Energy storage could address intra-hour uncertainties as well as hourly and daily uncertainties due to the intermittent profiles of wind and solar. The incremental intra-hour needs of regulation, operating reserves, and load following due to wind are well met by energy storage because, for these services, only 1-2 hours of storage may be needed. For the longer term uncertainties, the question of

how many hours of storage is adequate to fully back-up wind resources. Would 4 hours of storage be adequate to make the wind energy be dependable? 8 hours? 16 hours?

The answer is likely dependent on the existing system as well as the penetration of intermittent resources. At low levels of penetration, energy storage solutions could likely have a lower peak capacity to energy storage ratio. For example, with only 1,000 MW of wind in a 50,000 MW system, each energy storage installation might only need 2 MWh of storage for every 1 MW the installation is able to deliver on peak. At higher penetrations of wind, each energy storage installation might need 10 MWh of storage for every 1 MW of peak output.

The fundamental issue when crafting an energy storage solution for intermittent resources is to identify the most cost effective solution. Given the right energy storage technology, it may be possible to build enough storage capacity with tremendous energy reserves to be able to fully firm up all wind capacity. But is this economically efficient? Even if the cost of energy storage drops substantially in the future, the ideal economic solution likely includes only firming a portion of the wind fleet combined with a mix of types of energy storage. Additional simulations could be performed to design optimal energy storage resource expansion plans that minimize the cost of integrating wind.

D. DISTRIBUTED GENERATION

Distributed Generation (DG) is generation that produces electricity at or near the point of use and is generally small compared to centralized power stations. Distributed generation includes on site wind, solar arrays, micro-turbines, fuel cells, combined heat and power, and back-up or emergency power units. Based on a Department of Energy Report[66] released in 2007, there are an estimated 12 million distributed generation units installed in the U.S. with a combined capacity of approximately 200 GW. The report estimates that 84 GW of this capacity is consumer owned combined heat and power (CHP) systems and the majority of the remaining capacity consists of backup power units used only during emergency situations. These on-site units are generally not much larger than 1 MW in size, but in aggregate represent a large amount of capacity.

From a resource adequacy perspective, the difficulty with distributed generation is that utility system operators typically do not have full control to dispatch the resource during times of peak load. Because of this, the majority of these resources are typically not counted toward a reserve margin. An additional complexity raised by these resources is how load forecasts are accounting for the load that these resources are serving. As discussed in other sections of this paper, the proper counting of resources such as DG, DR, wind, and other energy limited resources is essential in optimal resource adequacy planning. To the extent that distributed generation owners and utility planners can better coordinate dispatch schedules and provide operators assurance that the resource will be available when called, there is potential for these resources to provide capacity in resource plans rather than through construction of new generation facilities. Generally, larger cogeneration and backup resources are counted but because the majority of all DG is less than 1 MW, a large percentage of these resources are not contributing to reserve margin calculations. States should continue to encourage this coordination, when cost-effective, in an attempt to further optimize resource adequacy.

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[66] *The Potential Benefits of Distributed Generation and Rate_Related Issues That May Impede Their Expansion,* retrieved on November 2, 2012 from http://www.ferc.gov/legal/fed-sta/exp-study.pdf

Aside from resource adequacy, states should help foster cost-effective DG by ensuring tariff rates and other subsidies such as investment/production tax credits are properly incentivizing these resources. Because of the size of these resources, new DG does not benefit from the economies of scale of a new traditional centralized power station and may need to make up the difference in order to be economically competitive with these traditional generation sources through specific advantages such as co-generation benefits, transmission benefits, fuel source, or subsidies. Regarding transmission, states should continue to ensure that interconnection rules and guidelines are fair and allow these types of resources to be developed.

X. ALTERNATIVES TO THE 1-IN-10 LOLE CRITERIA

A. NORMALIZED EUE

NERC has recently required all long assessment areas to perform probabilistic reliability studies for their systems and report a new metric which it calls "Normalized EUE". This is the percentage of load that was unserved.

Pros:

- The metric provides more information than LOLE because it incorporates the magnitude of the firm load shed event versus only counting the event.
- The metric is more easily comparable across regions because it calculates the magnitude of EUE as a percentage.

Cons:

- There is currently no threshold in place in the U.S. that has been studied stating that a system should be planned to meet a specific percentage of Normalized EUE.
- Normalized EUE doesn't take into account customer costs.

B. MINIMIZATION OF TOTAL SYSTEM COSTS

As the paper has discussed, assessing the reserve margin which produces the minimum system costs from the perspective of the consumer provides valuable insight.

Pros:

- Evaluating the economics provides customers and regulators with a sense of what the costs are for various levels of reliability and whether or not meeting a 1-in-10 LOLE standard is justified.
- An economic study better portrays the risk of resource adequacy. As seen in the results, reliability events are low probability but high cost events.
- Because firm load shed events are so infrequent, it is difficult to calibrate loss of load expectation models. Analyzing economics allows planners to know whether or not their reliability expectations are reasonable by being able to calibrate their economic results to actual historical costs.

Cons:

- Evaluating the economics alongside physical reliability metrics requires more effort.
- A few key assumptions such as the cost of unserved energy, cost of new capacity, and scarcity pricing have to be developed.

XI. RECOMMEND DETAILED PROCESS AND PROPOSAL TO ASCERTAIN THE ECONOMICS OF RESOURCE ADEQUACY

A. ENTIRE EASTERN INTERCONNECTION ASSESSMENT

Since this case study in this paper only used a subset of the Eastern Interconnection, we propose to the states that there would be value in examining the economics of resource adequacy as well as physical reliability metrics of the entire Eastern Interconnection. Analysis could be performed on an individual region basis as well as for the aggregate Eastern Interconnection. It is expected that an optimal economic reserve margin target for the Eastern Interconnection that is well coordinated and dispatched efficiently would likely be lower than a composite level resulting from target set by individual entities. Another view of the analysis could only analyze societal costs (fuel burn + O&M + unserved energy costs) across the Eastern Interconnection.

We propose using the EIPC data in a similar fashion to the way the data was used for this study. Load forecasts, fuel forecasts, and unit characteristics could all be obtained from EIPC data because the assumptions have already been well vetted by the participants. The data that would still need to be further developed or gathered to produce accurate resource adequacy results by entity and in aggregate would include the following:

- Distributions of load uncertainty due to weather for the remaining regions
- Distributions of load uncertainty due to economic growth uncertainty
- Actual historical generator availability data (GADS Data) by unit
- Demand resource characteristics
    - Reliability only
    - Economic
    - Call limits
    - Forecasted amounts
- Emergency Operating Procedures
    - Voltage reduction ability
    - Definition of when exactly a firm load shed event occurs (i.e. before or after depleting operating reserves, voltage control, etc)
- Wind and solar profiles by region and correlations to each other
- Hydro variability by region based on historical rainfall
- Energy efficiency projections by region
- Interface capability between regions and distributions around these assumptions representing the interface availability during peak conditions.

Astrape would recommend using a similar approach to the case study included in this paper. SERVM would be necessary to model the major uncertainties surrounding resource adequacy and capture all possible outcomes. It is expected that all benefits and costs associated with adding additional capacity across a range of reserve margins would be tabulated to gain a full understanding of the cost/benefit relationship. At the same time, it would be important to also calculate physical reliability metrics such as LOLE, LOLH, and EUE for all the scenarios simulated.

The topology for the Eastern Interconnection for the recommended study is included in the following figure. The regions within WECC and ERCOT would not be included in the analysis. The regions not already included in this paper's case study include HQ, IESO, NB, NEISO, MAPP US, NE, SPP-N, SPP-S, ENT, SOCO, and FRCC.

Figure 21. Study Topology[67]

The effort required to model the remaining areas in the Eastern Interconnection would not be inordinate given a significant portion has already been done. Astrape would propose incorporating actual historical GADS data rather than using the generic EFOR data provided in the EIPC data. Astrape would also need substantial collaboration regarding emergency operating procedures by each region as well as developing a better distribution of the transfer capability between regions.

Additional sensitivities surrounding market structure, scarcity pricing, demand response, and load forecast error assumptions should also be simulated to understand the impact they may have on the Base Case in this paper. Also the authors suggest simulating analysis using a different marginal resource such as demand response or combined cycle capacity.

It is anticipated that this effort could also result in state by state assessments of both the physical reliability and economic efficiency provided by the resource plans of utilities and other entities.

[67] Study would not include WECC or ERCOT

B. Additional Reliability Considerations With Evolving Resource Mixes

1. Demand Response Analysis

This paper demonstrated the importance of understanding demand response and how it impacts resource adequacy but many important questions have not been answered. If the full Eastern Interconnection model is developed, more meaningful analysis of DR programs is possible. Also, based on the data developed by the national labs for EISPC regarding demand response, there is much to be learned in this area with additional simulations. Scenarios to be explored could include:

- Simulating the 4 DR penetration possibilities developed by Oak Ridge National Laboratories[68] under the full range of weather, load and unit performance scenarios developed by Astrape. The penetration levels range from 6% - 30% and consist of a number of different types of programs.
- Assessing the energy and capacity value of pricing programs under a range of views of the future, including several of the alternate views explored in the EIPC study.
- Additional simulations assessing the impact of other contract constraints including days per week, hours per day, hours per month.
- Additional simulations to explore the impact of potential customer fatigue and changing price responsiveness.

2. Evaluating the Impact of Intermittent Resources on Operational Reliability

Because SERVM performs a full economic dispatch, the effort performed for the long-term physical and economic reliability assessments could be leveraged to analyze operational reliability. Although SERVM is an hourly model, intra-hour impacts could also be assessed by applying a distribution of 5-minute, 15-minute, and 30-minute uncertainty to the available resources in the model. Results of these simulations would allow planners to quantify the economic costs and reliability impact of increasing penetration of wind and solar from an operational standpoint. The costs of the necessary ancillary services such as regulation, load following, and additional operating reserves could be easily captured, as well as the financial impact of having to over commit resources to be able to ensure reliability will not be a concern. Potential mitigation strategies could also be explored using SERVM to identify the technologies and scheduling practices that protect reliability and minimize system costs in future environments.

3. Probabilistic Transmission Availability Impact

The data needs mentioned above anticipate the need for better transmission information, but do not include simulating probabilistic transmission component failures. SERVM could be used in conjunction with transmission modeling tools such as EPRI's TransCARE[69] to assess the combined generation and transmission reliability for discrete regions in the Eastern Interconnection. The scope for such an assessment has been developed separately by NARUC.

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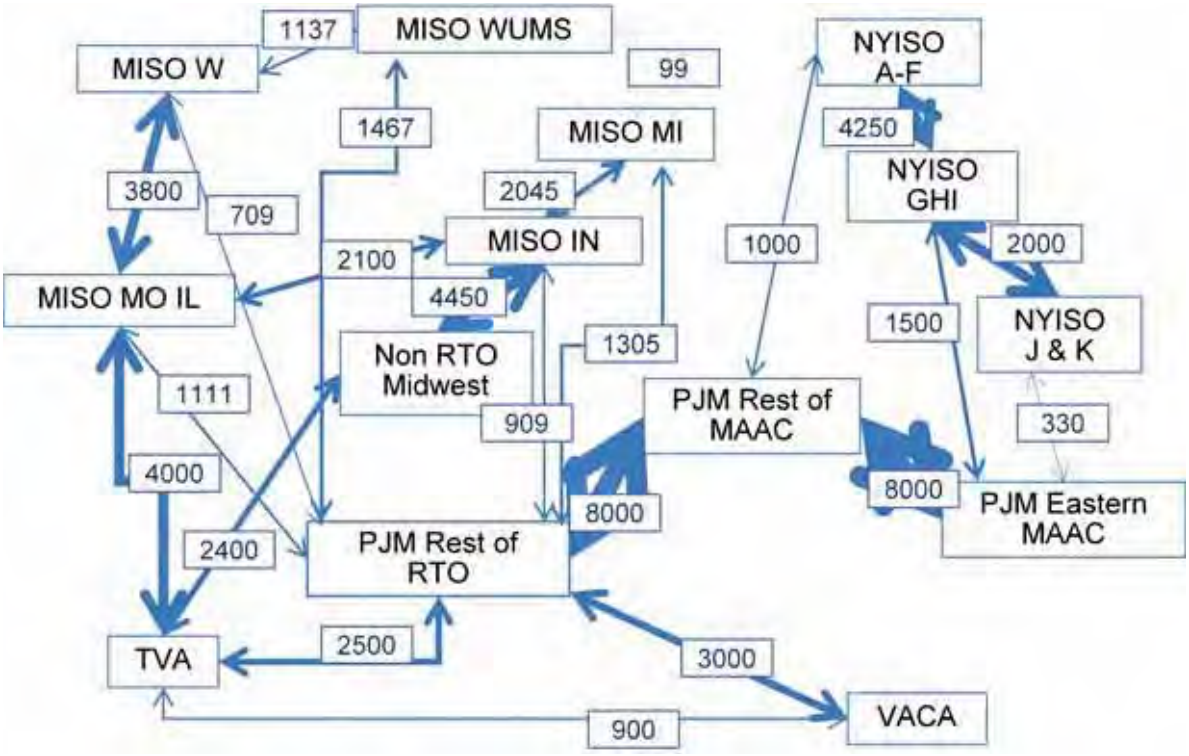
[68] Demand Response Assessment for Eastern Interconnection retrieved on Dec 1, 2012 at http://communities.nrri.org/documents/68668/19533034-7afe-4e7e-98fc-c4b511213871

[69] TransCARE is used is used for reliability assessment of composite generation and transmission systems.

XII. APPENDIX A

For the case study, Astrape Consulting constructed a model that included a significant portion of the Eastern Connection. All of the modeling data was taken from the current EIPC study including load forecasts, existing unit data, and transmission capability between regions. Below is the topology that was used for case study.

Figure A1. Topology



The resource adequacy software used for the case study is the Strategic Energy and Risk Valuation Model (SERVM)[70]. The probabilistic model was specifically designed for this type of analysis because it not only calculates traditional reliability metrics for a system (i.e. LOLE, LOLH) but also incorporates economic commitment and dispatch which allows for economics to be taken into account.

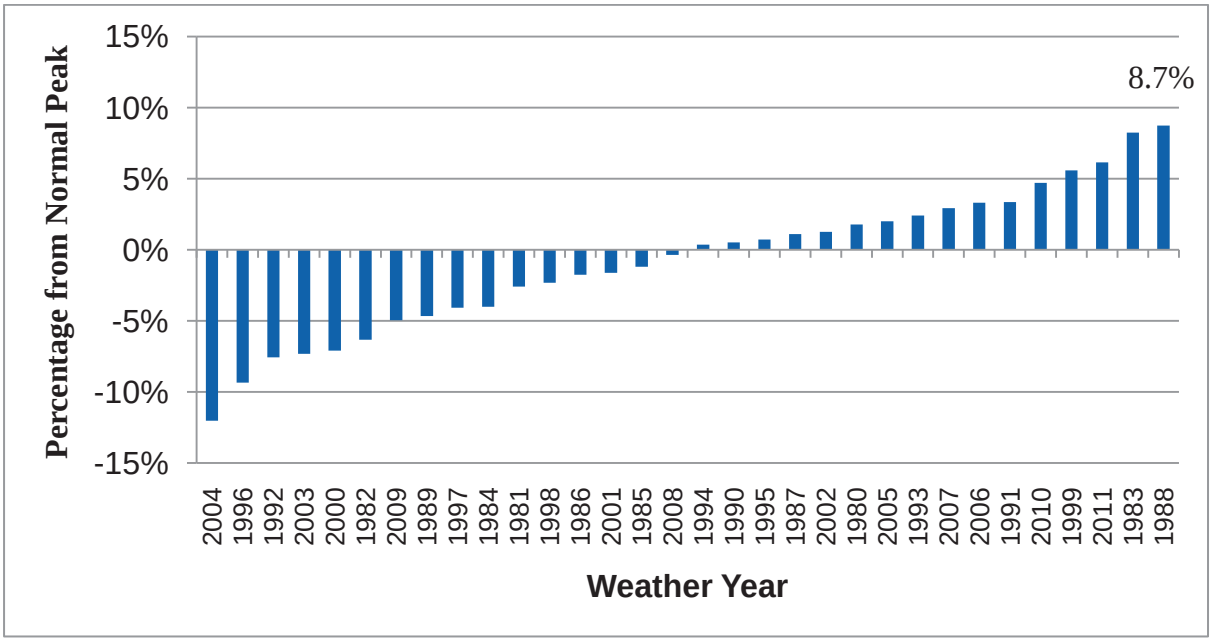
Resource adequacy studies have key attributes that differentiate it from typical production cost modeling studies. First, the study time frame typically examines one year in the near future versus studying longer time frames. This one year is then analyzed for all possible outcomes to assess the probability of a shortfall in capacity. For this case study, the year 2016 was chosen since it provides the lead time for new generation to be installed if reserve margin targets need to be changed. The most important variables driving capacity shortfalls include a combination of the following three uncertainties: weather uncertainty, economic load forecast uncertainty, and unit performance.

[70] SERVM is an economic resource adequacy model that is used by utilities to develop optimal reserve margin targets using economics as well as LOLE.

Weather

Weather uncertainty has an impact on both load and resources. The impact on load was modeled by simulating 32 synthetic load shapes representing the last 32 years of weather. Synthetic load shapes were created by developing a relationship between the last five years of load and temperature history using a neural net model. Each region has a unique load and weather relationship. These relationships were then applied to the last 32 years of weather to create 32 synthetic load shapes for each region. Each of these shapes represent what 2016 load could look like if the region experiences the same weather conditions from a historical year. Each load shape was given equal probability of occurrence in the simulation. The following figure provides an example of how high summer peak load can be above normal peak load for the PJM Rest of MAAC Region.

Figure A.2. Summer Weather Variability on Load for PJM_ROM



The following tables demonstrate the weather diversity incorporated into the loads. The first table shows on average over the 32 years of weather history, where each region is compares to its non-coincident peak load when the entire system peaks. The non-coincident peak of the system is 412,251 MW while the coincident system peak is 394,450MW which represents 4.5% weather diversity across the region.

Table A.1. Weather Diversity

Region	Average Load When Total System is Peaking (MW)	Average Non-Coincident Peak Load (MW)	Load Diversity with Neighbors (Region non-coincidental peak - Region coincidental peak)/(Region coincidental peak) (%)
PJM ROM	29,689	30,031	1.2%
PJM-E	35,731	36,143	1.2%
PJM ROR	105,726	107,319	1.5%
TVA	34,001	35,833	5.4%
VACAR	48,135	50,204	4.3%
NON-MIDWEST-ISO	11,272	11,729	4.1%
NYISO-A-F	11,154	11,934	7.0%
NYISO-G-I	4,220	4,515	7.0%
NY ISO-J-K	16,550	17,708	7.0%
MISO-IN	20,294	21,382	5.4%
MISO-MO-IL	20,434	21,530	5.4%
MISO-W	25,611	29,242	14.2%
MISO-MI	18,906	20,729	9.6%
MISO-WUMS	12,725	13,952	9.6%

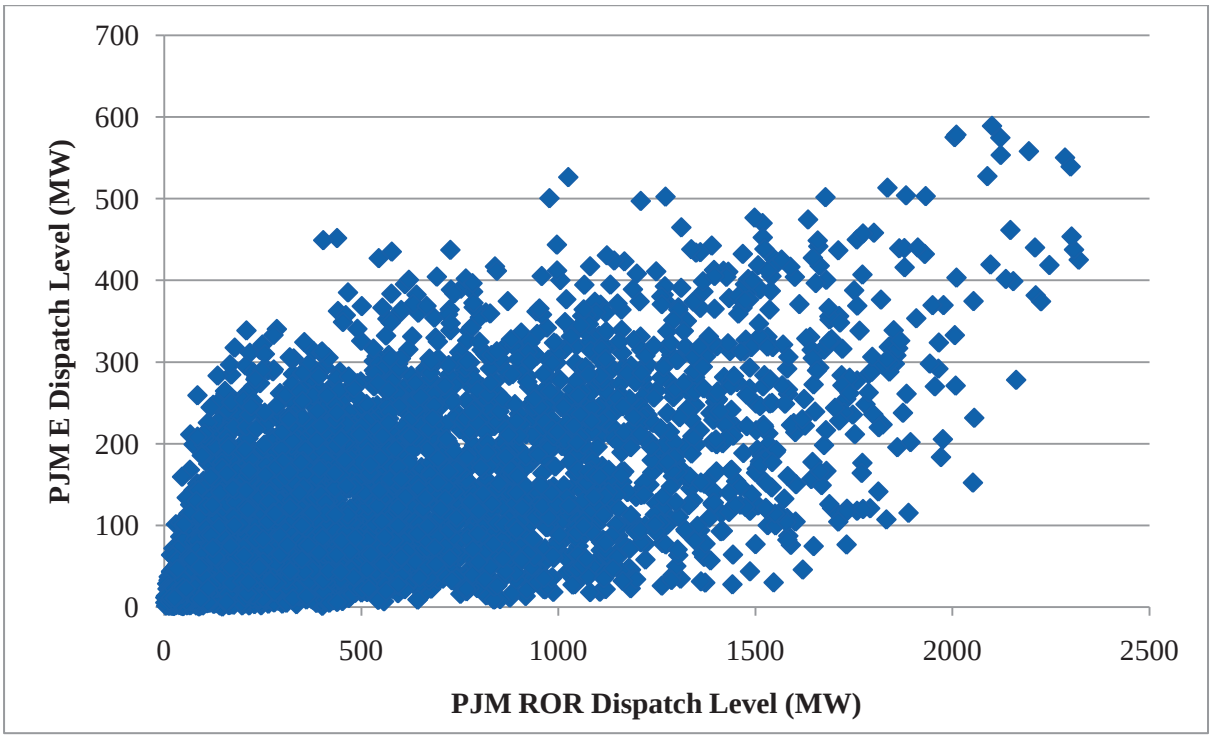
The next table represents the average of how far the neighboring region's load is relative to its own normal peak load in hours when the PJM_ROM is at its peak load. This is an average over 32 years of weather history. So on average, when PJM_ROM is at its peak load, then VACAR is within 6.7% of its normal peak load.

Table A.2. Neighbor Region's Load During PJM_ROM Region Peak

Region	Average Load When PJM_ROM is at its Peak Load (MW)	Average Non-Coincident Peak Load (MW)	Average Diversity with Study Region Peak Load (%)
PJM ROM	30,031	30,031	0.0%
PJM-E	36,143	36,143	0.0%
PJM ROR	103,682	107,319	3.4%
TVA	33,386	35,833	6.8%
VACAR	46,848	50,204	6.7%
NON-MIDWEST-ISO	10,880	11,729	7.2%
NYISO-A-F	11,022	11,934	7.6%
NYISO-G-I	4,170	4,515	7.6%
NY ISO-J-K	16,354	17,708	7.6%
MISO-IN	19,264	21,382	9.9%
MISO-MO-IL	19,397	21,530	9.9%
MISO-W	24,571	29,242	16.0%
MISO-MI	18,051	20,729	12.9%
MISO-WUMS	12,149	13,952	12.9%

Weather uncertainty also impacts the operation of hydro, wind, and solar resources. To take this into account, historical hydro energy data from each region was used to capture the amount of hydro energy available in each of the 32 weather years. For wind resources, the 2004 - 2006 EWITS data was utilized. The model draws stochastically by month and day from the 3 year period ensuring that the correlation from region to region is maintained. In other words, if July 5, 2006 was randomly drawn, then the profiles for all regions from that day were utilized. In examining the data, there was a significant correlation between regions as shown in the following figure. In hours when the PJM wind output was low, it was likely to be low in other regions as well.

Figure A.3. Wind Correlation between Regions (PJM_East/PJM_Rest of RTO)



The table below shows the capacity credit given to intermittent resources by region for the case study.

Table A.3. Capacity Credit of Intermittent Resources

NEEM Region	Technology	Capacity Credit
All Regions	Photovoltaic	30%
All Regions	Solar Thermal	30%
All Regions	Offshore Wind	20%
New York	Wind	10%
PJM (-E, -ROM, -ROR)	Wind	13%
TVA	Wind	12%
All Other Regions	Wind	15%

Economic Load Forecast Error

The second uncertainty - load growth forecast error - is the measure of the extent to which load forecasters will underestimate or overestimate economic growth for the next several years depending on the year being studied. The following distribution was used for the case study. This distribution was developed from a historical analysis of how well the Congressional Budget Office was able to forecast GDP four years in the future. The GDP uncertainty was converted to load uncertainty by multiplying by 40% - the assumed relationship of load growth to economic growth. The figure shows that in the most extreme case (lowest probability), load growth could be under forecasted by 5% over a four year period.

If it is assumed that demand response is the marginal resource, then it is likely that the economic load forecast error could be reduced to examine uncertainty over 1 – 2 years. The analysis completely changes under this approach because the capacity costs and benefit of a marginal DR resource are likely less than a marginal CT. The fact that the acquisition of DR is not unlimited also poses a concern in the authors' opinion.

Figure A4. Economic Load Forecast Error

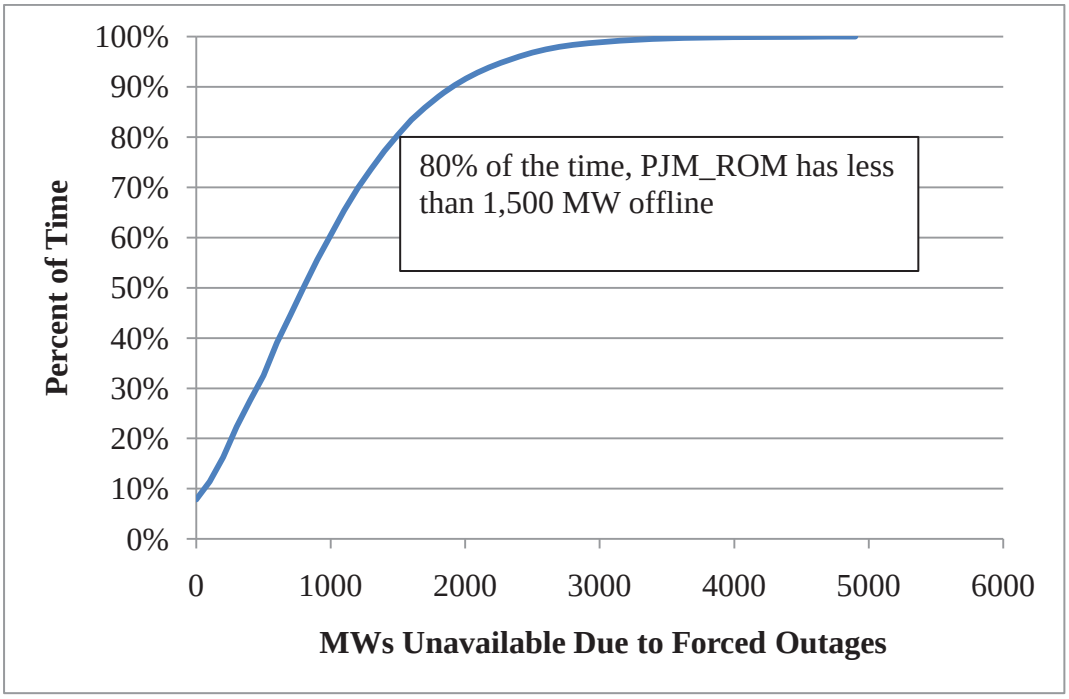
Load Forecast Error	Probability
5.11%	6.25%
3.90%	18.75%
0.55%	31.25%
-1.76%	18.75%
-2.90%	12.50%
-4.54%	12.50%

Unit Performance

The last major driver is unit performance. It is important to simulate the percent of time that a system will have a significant amount of generation offline due to forced outages, including partial outages. The model uses Monte Carlo techniques to simulate random generator failures. SERVM users actually enter in time to fail and time to repair distributions instead of a unit Equivalent Forced Outage Rate (EFOR). For this study, Astrape scaled distributions to achieve the target EFORs that were used in the EIPC Study. It should be noted that the EFOR data provided in the EIPC study was generic by unit type and that real historical GADS data would be needed for these results to provide more than an indicative conclusion.

The following chart shows a distribution representing the amount of MWs offline due to forced outage as a percentage of time. The figure shows that it is expected to have approximately 800 MW of capacity offline in a given hour, but that there are iterations where there can be several thousand MWs offline in a given hour. The chart also shows that 80% of the time the region will have less than 1,500 MW offline due to forced outages.

Figure A.5. Unit Performance Distribution



Hydro Modeling

SERVM utilized 32 years of historical hydro energy in the model. The variability of river flows can impact resource adequacy greatly. SERVM models the resources as either run of river, minimum flow constraints, or peak shaving. The total hydro capacity for each region was separated into the three categories. Run of river is defined as providing constant capacity for all 8760 hours of the year. The minimum flow constraints force the unit to be dispatched for at least a certain amount of hours each day at a certain capacity level. SERVM optimizes the dispatch around the peak for its peak shaving hydro resources.

Pump Storage Modeling

The pump storage resources are dispatched based on economics. The resources will pump during off peak hours and generate during peak hours if economic.

Demand Response Modeling

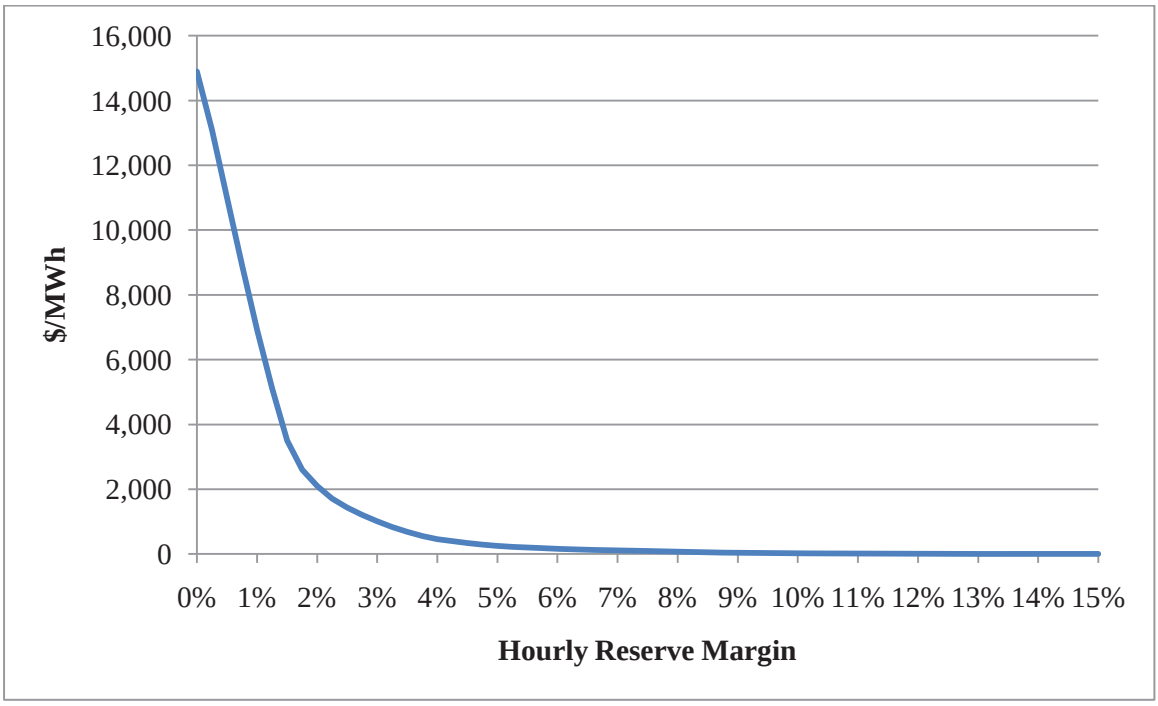
Demand response resources are modeled as capacity with specific call limits and strike price. For this case study, all demand response was given call limits of 150 hours per year and treated as reliability only with a dispatch price of $2,500/MWh. In other words, demand response was only called after all other alternative have been exhausted including expensive market purchases.

Scarcity Pricing

A scarcity pricing curve was developed by Astrape based on past experience of looking at historical market prices in different regions across the country. As the hourly reserve margin for a region decreases, the scarcity price approaches the VOLL. The following figure shows the curve that was actually used in the case study. The 0% level represents the point at which firm load is shed in order to maintain 2% spinning reserves in the case study. Because the modeling takes into account recent weather years, the authors

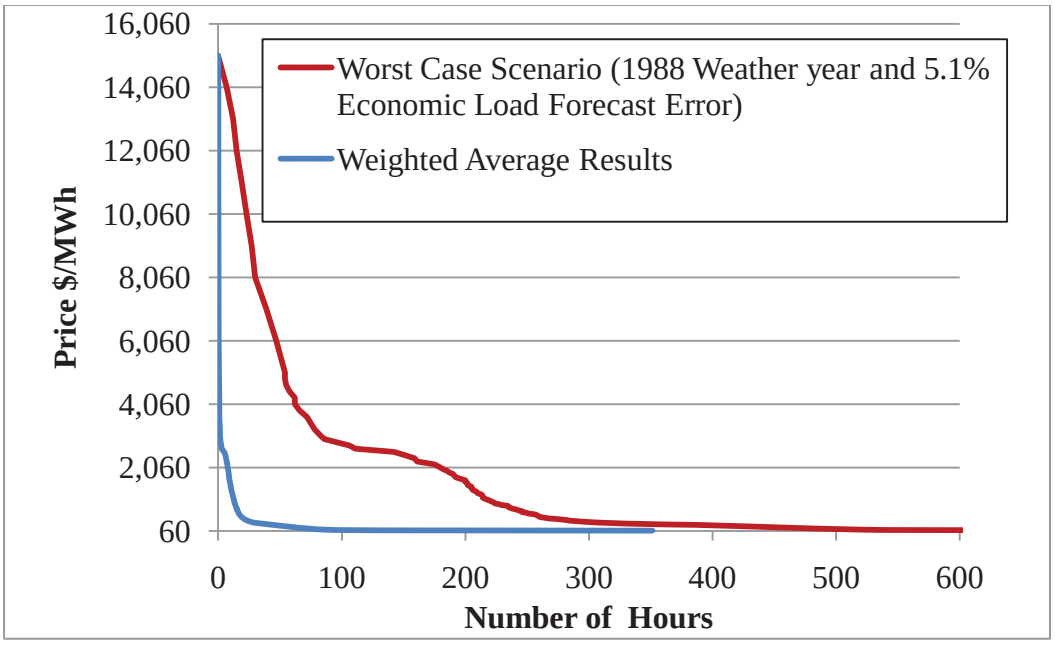
were able to compare energy margins from the model to actual PJM energy margins in 2010-2011 to get comfortable with the scarcity pricing curve.

Figure A6. Scarcity Pricing Curve



Based on the base case results, the following figure shows a price duration curve at a 10% reserve margin level for the weighted average of all scenarios and the worst scenario simulated shows the number of hours that are expected to occur at different market price thresholds. As expected, it is seen that prices above $2,000/MWh are rare.

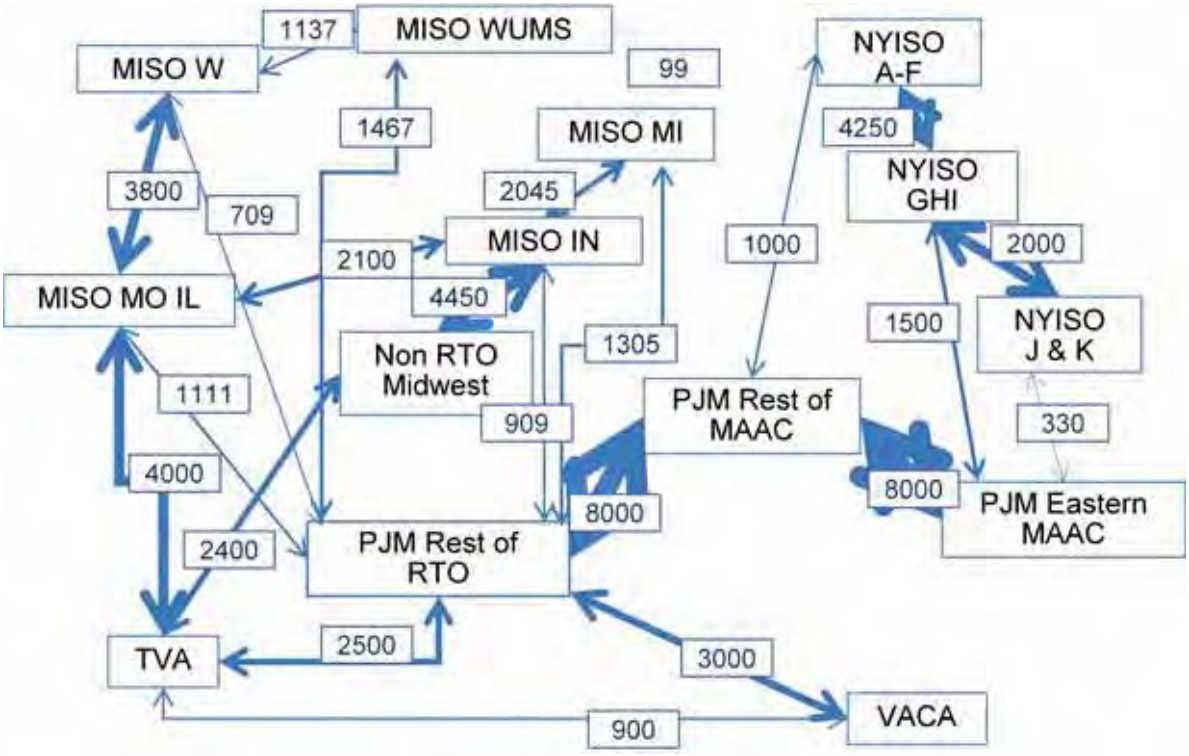
Figure A.7. Frequency of Scarcity Pricing @ 10% Reserve Margin



Transmission Interface

The following figure shows the transmission limits that were used for the Case Study which were direct inputs from the EIPC study. To perform more accurate simulations, Astrape suggests developing availability distributions for these interface limits rather than entering a constant value.

Figure A8. Transmission Interface Limits



Neighbor Modeling

SERVM's market clearing algorithms allow regions to share resources based on economics but subject to transmission limits. For example, if the TVA region is short capacity in a given hour, then their initial market price is equal to the VOLL. If VACAR is long, then VACAR can provide resources to lower the market price in TVA. If there was unlimited transfer capacity, then all regions would have the same hourly market price curve.

It should be noted that SERVM allows users to designate which resources can be shared. For this study, regions were not allowed to dispatch demand response resources in order to sell to other regions. Figure A.8 shows the target reserve levels for each NEEM Region in the study.

Figure A.9. Neighbor Target Reserve Margins

Reserve Margin Area	Reserve Requirement	NEEM Region(s)
MISO	17.4%*	MISO_IN
		MISO_MI
		MISO_MO-IL
		MISO_W
		MISO_WUMS
NonRTO_Midwest	14.0%	NonRTO_Midwest
NYISO	16.5%*	NYISO_A-F
		NYISO_GHI
		NYISO_JK
NYISO_GHI_JK	-5.0%	NYISO_GHI
		NYISO_JK
NYISO_JK	-8.0%	NYISO_JK
PJM	15.3%*	PJM_E
		PJM_ROM
		PJM_ROR
PJM_E	-2.2%	PJM_E**
TVA	15.0%	TVA
VACAR	14.0%	VACAR

** Based on coincident peak in reserve margin area.*

*** For purposes of this study, set equal to actual 2010 Reserve Margin*

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XIV. LIST OF ACRONYMS

CAISO	California ISO
CONE	Cost of New Entry
CT	Combustion Turbine
DR	Demand Response
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FRCC	Florida Reliability Coordinating Council
IESO	Independent Electricity System Operator
IOU	Investor Owned Utility
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
LSE	Load Serving Entity
LOLE	Loss of Load Events
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MAAC	Mid Atlantic Area Council
MAPP	Mid Continent Area Power Pool
MISO	Midwest Independent System Operator
NERC	North American Reliability Council
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
PJM	PJM Interconnection
SERC	Southeast Reliability Corporation
SERVM	Strategic Energy and Risk Valuation Model
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
VOLL	Value of Lost Load
WECC	Western Electricity Coordinating Council

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc. and MISO Transmission Owners' Settlement Agreement and Filing to Revise the Transmission Owners Agreement	**)** **)** **)** **)** **)**	**Docket Nos. ER13-708-000 and ER13-708-001**

COMMENTS AND MOTION FOR LEAVE TO ANSWER AND ANSWER OF THE ORGANIZATION OF MISO STATES

Pursuant to Rules 211, 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.211, 385.212 and 385.213, the Organization of MISO States ("OMS") hereby submits this Motion for Leave to Answer and Answer to the protests submitted by the Electric Power Supply Association ("EPSA"), the American Wind Energy Association ("AWEA"), and Dynegy Power Marketing ("Dynegy"), (collectively, "Protestors") in response to Midwest Independent Transmission System Operator, Inc. ("MISO") and the MISO Transmission Owners' ("MISO TOs") (collectively, "Filing Parties") January 4, 2013, filing ("January 4 Filing") proposing enhanced authority for the OMS pursuant to Section 205 of the Federal Power Act.

With this pleading, OMS also submits comments on the Filing Parties' revised filing of February 28, 2013, pursuant to the Commission's Combined Notice of Filings and associated comment deadlines issued on February 28, 2013.

I. MOTION FOR LEAVE TO ANSWER

OMS seeks leave to respond to the pleadings filed by the Protestors in the above-captioned docket. Although the Commission does not usually permit answers to protests, it has done so to aid in the decision making process or to correct and clarify the record.[1] That is the case here. This Answer will clarify mischaracterizations of OMS's arguments and issues, thereby facilitating the Commission's review.

II. ANSWER

A. Regulators Are Not Merely Another Stakeholder.

The Protesters mischaracterize OMS as merely another stakeholder and allege that the January 4 Filing would establish an imbalance in the stakeholder process.[2] EPSA argues that the filing would allow "one group of stakeholders to enjoy preferential treatment and greater influence over the other stakeholder groups."[3] AWEA asserts that the January 4 Filing would "set state regulators, as a single stakeholder group, above all other stakeholders in the MISO process."[4] Dynegy argues the January 4 Filing would create preferential rights for OMS "well beyond the rights of all other stakeholders."[5] The Protesters request that FERC either reject any increased rights for OMS, or provide similar rights to all other stakeholder groups.[6]

OMS is not merely another stakeholder. As the Commission has recognized, OMS, and state regulatory committees like it, serve an important and unique role in

[1] See, Southwest Power Pool, Inc., 131 FERC ¶ 61,252 (2010); Virginia Electric and Power Company, 124 FERC ¶ 61,207 (2008).
[2] EPSA Protest at 2; AWEA Protest at 7, 8, 13, 14, and 15; Dynegy Protest at 4, 5, 6, and 7
[3] EPSA Protest at 2.
[4] AWEA Protest at 8.
[5] Dynegy Protest at 4.
[6] EPSA Protest at 6.

implementing the transmission planning and transmission cost allocation goals of Order 1000.[7] In Order 1000, the Commission affirmed that state regulators play a crucial role in transmission planning and cost allocation and that the role of state regulators is unique and distinctly different from the roles played by other stakeholders.[8]

As reflected in Order 1000, and unlike any of the other stakeholder groups, the objective function for OMS and the state commissions is safeguarding the public interest. State commissions have responsibility under state and federal law for issues such as resource adequacy, infrastructure planning and siting, and retail ratemaking, among many others. To accomplish these goals, state commissions balance many interests, including those of utilities operating within their states and their customers, consumer advocates, environmental protection groups, industrial groups, generation owners, and other interested parties. In other words, state commission responsibilities are inherently interrelated with MISO's transmission planning and cost allocation functions and both MISO and the state commissions have fundamental roles in considering and serving the public interest.

This is not a new concept. The Commission has recognized a unique role for state regulators in MISO, enabling state commissions (and the OMS) to act in conjunction with MISO while providing state commissions an opportunity to make decisions about which projects will be placed in the transmission plan and how costs of such projects will be allocated.[9] Protesters ignore Commission precedent approving similar enhanced authority for

[7] OMS Comments, at 4 citing various paragraphs of Order 1000 (emphasis added).
[8] OMS Comments, at 4 citing various paragraphs of Order 1000.
[9] Midwest Independent Transmission System Operator, Inc., 133 FERC ¶ 61,221, P212 (2010). The OMS notes, however, that it has been careful to avoid actions that would create an appearance of prejudgment as

regional state committees in the past. The Commission approved allowances for the Southwest Power Pool Regional State Committee to direct filings under Section 205 of the Federal Power Act.[10] The same is true with respect to the Commission's consideration of the powers of the Entergy Regional State Committee ("E-RSC"); the Commission authorized the E-RSC to direct Entergy to file alternative transmission cost allocation proposals and to add transmission projects to Entergy's construction plan.[11]

The Protesters do not and cannot distinguish the enhancements proposed by MISO in the January 4 Filing from similar enhancements already authorized by the Commission.[12] The Commission should reject Protesters' arguments in light of precedent demonstrating that state regulators are "not just another stakeholder."

B. OMS is Clearly Not a Market Participant.

Protestors would have the Commission incorrectly categorize OMS as a market participant to support their argument that the January 4 Filing would violate the principles of Order Nos. 719 and 2000 and threaten MISO's independence.[13] These arguments are inherently flawed.

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to particular projects that might later come before a member commission for construction approval or cost recovery.

[10] *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 219-220, *order on reh'g*, 109 FERC ¶ 61,010 (2004)

[11] *Entergy Arkansas, Inc., et al.*, 133 FERC P 61,211, at ¶¶ 5 and 6.

[12] These past decisions were specifically referenced in OMS's earlier comments. Specifically, OMS requested that the Commission review the January 4 Filing "within the multiple contexts of integrating the Entergy Companies into MISO, the section 205 filing rights granted to the E-RSC and SPP RSC, the Commission's requirements under Order 1000, and the Commission's observations after ten years of experience of regional state committee operations in several RTO/ISO regions, and the OMS's performance specifically." OMS Comments at 10.

[13] EPSA Protest at 4. AWEA at 8-9. Dynegy Protest at 4.

First and foremost, OMS and its members are not market participants.[14] OMS owns no generation or transmission, serves no load, purchases no power and does not engage in virtual market transactions. In short, OMS members have no economic or commercial interests that are likely to be affected by MISO's decisions and actions. As explained above, OMS is comprised of retail regulators that protect the public interest.

In Order 2000, the Commission established a requirement that an RTO "must have a decision making process that is independent of control by any market participant or class of market participant."[15] As OMS and its members are not market participants, there can be no concern that this requirement would be violated by the January 4 Filing.

Second, MISO and the MISO TOs are offering to extend these enhanced authorities to the OMS. A voluntary extension of enhanced authority cannot threaten MISO's independence, which was addressed at length in MISO's and the TOs' January 4 Filing and more recent Answer.[16]

Third, Protesters' reliance on Order No. 719 is misplaced.[17] Order 719 requires MISO to consider and balance the interests of its customers and stakeholders in its practices;[18] the same role that state commissions play. Consequently, enhancing the role

[14] Order No. 2000, at 194-195. Specifically, the Commission identified that a market participant is an entity that: (1) either directly or through an affiliate, sells or brokers electric energy, or provides transmission or ancillary services to the Regional Transmission Organization…; and (2) any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions.
[15] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. &Regs. ¶ 31,089 at 195 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. &Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) (emphasis added).
[16] Answer to Pleading/Motion of Midwest Independent Transmission System Operator, Inc. at 4-7.
[17] EPSA Protest at 4, AWEA Protest at 9, Dynegy Protest at 5.
[18] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. &Regs. ¶ 31,281 at P 507 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. &Regs.¶ 31,292, *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009), at P 507.

of a regional state committee is consistent with Order No. 719. Likewise, Order No. 719 requirements parallel Order No. 2000's "independence from market participants" requirement,[19] which, as established above, is not relevant as OMS and its members are not market participants.

In summary, Order Nos. 2000 and 719 support, rather than undermine as protestors would have it, the appropriateness of enhancing OMS's transmission planning and cost allocation roles in MISO.

C. Conclusion of Answer

For the reasons stated above, and considering the Protesters' arguments do not accurately state the essential characteristics and interests of OMS, the Protestors' arguments should be rejected. To the extent necessary, the OMS also reiterates its Comments previously filed in this proceeding.

III. COMMENTS

On February 28, 2013, MISO and the MISO TOs filed an Amended Settlement Agreement Between the Transmission Owners and the Midwest Independent Transmission System Operator, Inc. regarding Modified Filing Rights ("Amended Settlement Agreement"). The Amended Settlement Agreement deletes language stating that MISO would determine the appropriate resources needed to support an OMS alternative Section 205 proposal. This issue was addressed in the OMS's Comments[20] and the Arkansas Public Service Commission also expressed concerns with the language

[19] See, EPSA Protest at 4. AWEA Protest at 9 and Dynegy Protest at 4 all citing *Regional Transmission Organizations*, Order No. 2000, FERC Stats. &Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[20] OMS Comments (February 8, 2013), at 6-7.

originally submitted with the January 4 Filing in this regard.[21] OMS appreciates MISO and the MISO TOs' prompt action to correct the language and supports the February 28 revision.

IV. CONCLUSION

The OMS seeks leave to answer and submits the above answer to the protests submitted in this proceeding. The OMS also submits its Comments on the Amended Settlement Agreement submitted by the Filing Parties on February 28. The OMS urges the Commission to reject the requests and recommendations of the Protesters and supports the modifications proposed in the Amended Settlement Agreement.

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate pleadings regarding the issues discussed herein. The following members generally support these comments:

Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
Montana Public Service Commission
City of New Orleans
North Dakota Public Service Commission
South Dakota Public Utilities Commission
Public Utility Commission of Texas
Wisconsin Public Service Commission

[21] Motion for leave to submit brief comments out of time and comments of Arkansas Public Service Commission under ER13-708-000.

The Manitoba Public Utilities Board did not participate in this pleading.

The Minnesota Department of Commerce, as an associate member of the OMS, participated in these comments and generally supports these comments.

Respectfully Submitted,

William H. Smith, Jr.

William H. Smith, Jr.
Executive Director
Organization of MISO States
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Tel: 515-243-0742

Dated: March 20, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding. Dated at Key West, Florida, this 20st day of March, 2013.

William H. Smith, Jr.

William H. Smith, Jr.

OMS Governance & Budget Work Group Status Report **March 14, 2013**

The **OMS Governance and Budget Work Group** (G/B WG) is responsible for assessing the reasonableness of the Midwest ISO's new products and services, strategic plan, short-term and long-term incentive plans, governance and budgets.

Work Group Update:

1. Reviewed OMS bylaws for needed or desirable updates in anticipation of possible enhanced state authority: e.g., additional Advisory Committee representatives; creation of a Regulatory Committee; expanded role in transmission planning. Because details are still forthcoming, this work remains preliminary in nature.

1. MISO April AC Hot Topic: Market Enhancement Priorities

Status: Waiting for questions from MISO, then meet to prepare draft comments.

As outlined in a 2/28 e-mail to the WG, we expect to prepare draft comments for the OMS Board to approve at the April Board meeting. The comments will respond to questions (that are still being prepared by the AC Hot Topic drafting team) to help MISO identify, plan, and prioritize projects in relation to each other and in relation to non-market efforts. MISO recently presented its plans to improve its market development process to the MISO Board of Directors Markets Committee (on 2/20/13), where MISO will seek stakeholder and consultant feedback towards developing a "longer term strategic market roadmap." The presentation is at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=147061

2. FERC Electric and Natural Gas Scheduling Coordination AD12-12-000

Status: FERC technical conference scheduled for 4/25/13

The FERC has scheduled a technical conference that will focus on coordination of scheduling and the gas/electric day. Recall that OMS commented on to FERC on 3/30/12, 8/17/12, and at the 8/6/12 Central Region conference. In the 3/30 comments, OMS expressed concern about the number of natural gas day nomination cycles and the "no bump" rule and requested a technical conference in these wholesale market-related issues. We notified the WG via e-mail on 3/12/13. Requests to participate are due by 3/15. There may be opportunity to comment after the conference.

3. MISO March 12 Trading Hubs Task Force meeting

Status: The OMS M&TWG is monitoring.

At the 3/12 meeting, MISO agreed with survey results to use the 2010 PROMOD Study and refresh with critical assumptions, then discussed with stakeholders next steps towards establishing a new southern region trading hub, including what critical input assumptions to use to update the 2010 PROMOD Study for hub analysis. The WG held a meeting with MISO on 2/27/13 and discussed, among other things, the importance of establishing a trading hub in time for Entergy integration. Five OMS states submitted surveys, providing significant input. Thanks to Tia Elliot (IN) for leading the WG discussion.

4. MISO-PJM Beaver Channel M2M Re-Settlement

Status: WG meeting planned for 3/19/13 at 10 a.m. CDT.

The WG will meet to talk about MISO's recent refund of about $7 million in market-to-market charges to PJM. OMS has not reacted or taken any position to date. A group of MISO Load Serving Entities (LSEs) have disputed charges on MISO settlements (Nov 14 and 21/2012) for the refund. During the 12/4/12 MSC meeting, MISO and the IMM responded to a set of questions that concerned stakeholders submitted. During the discussion, MISO held firm to its belief that the refund was warranted, and the IMM held firm to his belief that it was not. We discussed this with MISO's IMM on 12/7/12, who further explained why he opposes the refund. On 1/28/13, MISO held a special stakeholder meeting to respond to further questions from the LSE group.

5. MISO Ramp Capability Technical Workshop Feedback Request

Status: Waiting for MISO to schedule technical workshops.

We notified the WG via 3/1/13 e-mail of a MISO request for feedback on the interest for more technical sessions on its Ramp Capability Enhancement proposal. As reported in more detail in prior status reports, MISO proposes to complete its proposal by the first quarter of 2013 so it can file at FERC by the middle of this year and implement by March, 2015, which would be after Extended LMP goes into effect on October, 2014. On 2/15, two WG members (IN, MI) submitted feedback supporting additional sessions.

6. MISO March 6 FTRWG Meeting

Status: The OMS M&TWG is monitoring.

Items covered include a WPPI Energy proposal for secondary purchasers to qualify for Reserve Source Points the same as primary purchasers, all towards qualifying for ARRs and FTRs. There was also a discussion on FTR funding drivers. Congestion and FTR funding shortfalls have increased starting mid- 2012, and MISO expects this to continue for the next 3 months. Congestion increased $951 million in 2011 to $1.353 billion in 2012. The FTR funding shortfall is $33 million in 2012 and $59 million so far this year. Contributing reasons include not accounting for removing constraint relaxation, increased Dispatchable Intermittent Resources, and a reduction of manual wind curtailments in the 2012 auction. With DIRs, congestion is now being priced, where in the past MISO curtailed manually before congestion occurred. MISO intends to address this in the 2013 annual auction.

7. MISO March 5 MSC Meeting

Status: The OMS M&TWG is monitoring.

Items covered include the status of work on a new southern region trading hub, a summary of two recent FERC filings for RSG changes (RSG charge exemption for TLRs ER13-980-000, and correct the CMC sign convention error ER13-984-000), IMM recommendations to revise RSG cost allocation, a discussion on FTR funding drivers, resource adequacy timeline, and DIR update. DIR registered is now 9,533 MW of total 12,238 MW registered wind, with 2,694 MW exempt. MISO also reported a recently discovered M2M error between MISO and PJM that will result in a $4 million refund to MISO from PJM for 10/12 through mid-2/13. MISO will provide details at the April MSC meeting.

For items that MISO expects to work on and seek input on during 2013, please see last month status report.

8. M&T WG leadership

Status: Looking for volunteers.

We are looking for a volunteer to co-chair the M&TWG. We are also looking for volunteers to help gather questions and help run the quarterly OMS calls with the IMM.

For those interested, please note the following MISO meetings:

MISO Board of Dirs Markets Committee – bi-monthly meetings (4/24 next mtg)
MISO Market Subcommittee - monthly meetings (4/2 next mtg)
MISO FTR Working Group – monthly meetings (4/3 next mtg)

The **OMS Markets and Tariffs Work Group** covers: Energy and Operating Reserve markets, Market Monitoring and Mitigation. See
http://www.misostates.org/index.php/work-groups-2/workscopereference/63-markets-a-tariffs-workscopereference
http://www.misostates.org//images/stories/work_groups/2013OMSworkgroupOvervie_28_February2013.pdf

Bill Bokram, Markets and Tariffs Work Group co-chair

OMS Resources WG Report to OMS Board – March 14, 2013

MISO SAWG

The March 7th SAWG meeting had a long discussion about the outcome of the resource adequacy auction concerning Grand Mother Agreements (GMA) and Fixed Resource Adequacy Plans (FRAP). MISO made an initial determination of the tariff to exclude any Zonal Deliverability Benefit (ZDB) allocation to an LSE who chose FRAP over auction and self-supply as a price taker. The LSE coalition (through David Sapper) pointed that was not a consistent interpretation of the tariff. Two Wisconsin utilities were also pointed other problematic issues including fuel clause rules. On Monday March 11, MISO reversed their interpretation and those who choose the FRAP option instead of self-supply will be allowed any ZDBs if they exist.

The mock auction was closed the 11th. The results of the auction will be review March 18th.

The new Southern Region integration timeline is below:

MISO Southern Region Resource Adequacy Integration Timeline

Process	Responsible Entity	Deadline*
File New Local Resource Zones with FERC	MISO	7/15/13
Generation Resource Test Data (GVTC) and Availability Data (GADS) Due for all generators	Resource Owner	7/31/13
File new Cost of New Entry (CONE) values for each Local Resource Zone with FERC	MISO	8/15/13
Capacity Resource UCAP values published to Module E Capacity Tracking Tool	MISO	9/1/13
LCR, CIL, and CEL Limits for each LRZ Published	MISO	10/1/13
Annual Coincident Peak Forecast Data Due	LSE, EDC	10/18/13
Grandmother Agreement Hedge Registrations Due	LSE	10/18/13
Load Modifying Resource, EER, External Resource Registrations Due	Resource Owner	10/18/13
Fixed Resource Adequacy Plans (FRAP) Due	LSE	10/23/13
FRAP review by MISO completed	MISO	10/25/13
Transitional Planning Resource Auction Offer Window Open	MISO	11/8 -11/12
Deadline to elect to pay Capacity Deficiency Charge	LSE	11/12/13
Transitional Planning Resource Auction Results Published	MISO	11/19/13

MISO *Dates consistent with E-2 tariff filing and subject to change pending FERC approval 2

Submitted by Don Neumeyer, Chair Resources Work Group

OMS Regional Planning Work Group
Report to OMS Board of Directors – March 14, 2013
(Co-Chairs Jessica Govindan and Julie Urban)

PAC Update

MISO provided a final review of the MTEP 13 futures as voted on by PAC by email in mid-February. Next steps for MTEP futures, include requesting sector weighting of the five futures. MISO has yet to send around the survey, however when they do the Regional Planning WG will take the lead and gather the OMS average for input back to MISO. MISO also discussed stakeholder feedback and concerns to both the Out of Cycle Review Process proposal and Project Status Update proposal. These discussions will continue at the March PAC meeting. The next Pac meeting is scheduled for March 20th.

MISO requested feedback from stakeholders on several PAC issues, including Out of Cycle Project Review Process, Market Participant Funded upgrade BPM language, Project Status Update Proposal, and Merchant HVDC Interconnection Process. All feedback was due 3/8 – 3/13. Due to time constraints and other OMS assignments the WG provided comments on these issues:

- Out of Cycle Review Process – These remained in line with our previous Staff comments from October 2012 and February 2013, reiterating certain issues addressed by staff that MISO did not incorporate into their latest straw proposal. We also addressed the need for making sure that OOC projects are applicable to MISO's proposed enhanced project status update proposal being discussed in parallel with stakeholders (below).
- Project Status Update Proposal – RPWG drafted edits to MISO's draft BPM language establishing a milestone approach for eligible transmission projects to make sure additional detailed information is provided to MISO and stakeholders at key points in a project's life before construction. RPWG staff stressed the need to establish a clear link within this process between when detailed information (status and cost estimates) would be required, when it would be due, and at what point that information is needed to make informed decisions. This was a major weakness of MISO's current proposal. Staff provides substantive redline edits to MISO; to be discussed at the March PAC.

MISO BOD Guiding Principles Update from System Planning Committee of MISO BOD

At MISO's System Planning Committee meeting on March 11th, MISO staff provided committee members with proposed edits, reflecting MISO staff and stakeholder suggestions from the last PAC meeting, including the OMS BOD suggestions. MISO staff walked through the rationales for each of the suggested edits, saying for the most part changes were made to better clarify the original intent, where applicable.

In particular, the edits for principles 1, 4, and 6 reflect OMS suggestions. MISO staff will also be creating a MISO Whitepaper as a companion to the suggested edits that will explain in greater detail the intent of each principle and any important issues addressed by stakeholders and the Committee members during this meeting. The Committee unanimously voted in support of sending the draft as edited during this meeting to the full MISO BOD for approval in April.

Guiding Principles Document

FERC Order 1000 Compliance – Interregional Planning and Cost Allocation

FERC granted 90-day extension for Order 1000 Interregional Compliance filings. Now due July 10, 2013

MISO has been continuing to work with its neighbors on establishing or improving interregional planning and cost allocation methodologies. MISO expects that three of the four interregional compliance filings will be ready to file with FERC in the April/May timeframe (PJM, SPP, MAPP). **MAPP**: MISO and MAPP reached an agreement on model and data exchange requirements, which follow closely to what MISO has with SPP and PJM. **PJM**: MISO and PJM TOs agree to justify existing cross-border cost allocation methods as Order 1000 compliant. **SPP**: MISO and SPP do not have agreement on everything, however they will file at least what has been agreed to (interregional planning processes and cost sharing for 345kV and above MEPs) **SERTP**: MISO and SERTP have begun discussing the timeline for addressing Order 1000 compliance. Still requesting a filing extension deadline of August 2013.

TO: OMS Board

FROM: Chairman Phil Montgomery, Public Service Commission of Wisconsin
Tia Elliot, Chris Devon and Brian Rybarik

RE: States' Seams Work Group (SSWG) Update

The following update from the SSWG provides information on the most recent Joint and Common Market (JCM) Initiative meeting, the latest meeting of the MISO Seams Management Work Group (SMWG); as well as, the upcoming State Seams Work Group.

There was no JCM Meeting in February. The next JCM is scheduled for Thursday, March 21st in Carmel, Indiana at MISO. However, a critical issue discussed at the previous JCM in January, was the inclusion of a more formal role for state regulators in the JCM meetings. It was at this time; Chairman Montgomery announced the formation of a JCM Stakeholder Working Group.

The first JCM Stakeholder Working Group Meeting was held by teleconference on Friday, March 1st. There were a number of stakeholders on the phone from multiple sectors in both MISO and PJM, as well as, staff from both RTOs. Chairman Montgomery and Commissioner White led the discussions, which included topics on governance and processes for the JCM. There seemed to be some consensus among stakeholders for the JCM taking on a more formal role, instead of continuing as an ad hoc group. Consideration was given to making recommendations for the JCM to either have a Chair and Vice Chair or a moderator; in addition to, keeping meeting minutes and real time notes. MISO and PJM agreed to schedule the JCM Meetings through the end of 2013; plus, have these dates ready for stakeholders by the next JCM Meeting. The next JCM Stakeholder Working Group is scheduled for Monday, March 18.

On February 14th, the OMS State Seams Working Group (SSWG) held a meeting to discuss the upcoming MISO JOA Workshop. The SSWG compiled a list of recommendations for the MISO JOA Workshop:

1. Review of Utilicast Baseline JOA Report Recommendations published in March 2012,
2. Overall Flow Chart of Working Groups because there are so many layers identified under the JOA,
3. Identify the Process and Procedures for Flow Gate Monitoring,
4. Requested Further Context on Typical Dispatch Development,

5. Update on Generation and Transmission Outage Data Exchange between the RTOs, and
6. Identify a Timeline for Market to Market (M2M) Coordination Improvements (as discussed in the JCM).

The MISO Seams Management Work Group (SMWG) was cancelled in March because MISO held a JOA Workshop, in place of the SMWG Meeting. This was the first JOA Workshop MISO has held since early 2011. The workshop focused on the MISO-PJM JOA at a high-level. Many stakeholders considered the workshop to be a success. It was very informative. The OMS SSWG had submitted recommendations to MISO, for the JOA Workshop. These were included on the agenda; however, there was not enough time to get to these items due to the engaging discussions. MISO has committed to either hosting a continuation of the workshop or adding these discussion items from the SSWG, onto the agenda of an upcoming MISO SMWG agenda.

Another JOA Workshop, for MISO and SPP, is scheduled for March 26th in Dallas, TX.

The next MISO SMWG is scheduled for April 1st.

On February 5th, OMS and OPSI Filed Joint Comments at FERC in AD12-16 on Capacity Deliverability. These comments were in response to a Request made by MISO, to FERC; on January 3rd. PJM filed an Answer in AD12-16, on February 11th, in which PJM referenced the Joint OMS-OPSI Comments. Then, on March 5th, MISO filed an Answer in AD12-16. It addressed the Joint OMS-OPSI Comments, as well as, the Comments filed by the IURC. While it wasn't a direct apology, it was as close as MISO has come to giving one.

This is what Chris Devon looked like **just before** "the incident." Get well soon Chris!