UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Michael M. Gibson, Chairman
Dr. Gary S. Arnold
Dr. Randall J. Charbeneau

In the Matter of NUCLEAR INNOVATION NORTH AMERICA LLC (South Texas Project Units 3 and 4)	Docket No. 52-12-COL and 52-13-COL ASLBP No. 09-885-08-COL-BD01 January 3, 2012

MEMORANDUM AND ORDER
(Providing Proposed Questions for Evidentiary Hearing on Contention CL-2)[1]

Pursuant to 10 C.F.R. § 2.1207(a)(3)(iii), this issuance and the accompanying attachments provide the proposed questions submitted to the Licensing Board by Intervenors,[2] NRC Staff, and Applicant in connection with the evidentiary hearing on Contention CL-2, held on August 18 and 19, 2011 in Austin, Texas.

It is so ORDERED.

FOR THE ATOMIC SAFETY
AND LICENSING BOARD
/RA/

Michael M. Gibson, Chairman
ADMINISTRATIVE JUDGE

Rockville, Maryland
January 3, 2012

[1] Redacted material contained in several of the attachments concerns proposed questions regarding Contention DEIS-1-G, on which this Board has not yet ruled.

[2] Intervenors are three public interest organizations: the Sustainable Energy and Economic Development Coalition, the South Texas Association for Responsible Energy, and Public Citizen.

ATTACHMENT 1

Intervenors' Proposed Questions Regarding Contention CL-2

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD PANEL

In the Matter of
South Texas Project Nuclear Operating Co.
Application for the South Texas Project **Docket Nos. 52-012, 52-013**
Units 3 and 4 **July 12, 2011**
Combined Operating License

INTERVENORS PROPOSED CROSS EXAMINATION

Contention CL-2

Staff witnesses

1. Do the witnesses admit that applying the Staff's averted costsmakes the averted costs greater than SAMDA implementation costs whether a 3% or 7% discount is used?Reference direct testimony Q/A 34 and rebuttal testimony Q/A 5:

2. Do the witnesses admit that SAMDA projects are narrower in scope than overall nuclear plant construction costs?

3 Do the witnesses admit that the structure component index is not the only index comprising GDP private non-residential fixed investment?

4. Do the witnesses admit that equipment and software is another component of the GDP private non-residential fixed investment?

5. Do the witnesses admit that for the time period 1991-2009 the GDP private non-residential fixed investment equipment and software index component reflects negative growth?

6. Do the witnesses admit that their application to SAMDA of the GDP private non-residential fixed investment did not account for the negative growth from 1991-2009 of the equipment and software index component?

7. Do the witnesses admit that a negative growth from 1991-2009 of the equipment and software index component results in a lower SAMDA costs than reflected in their testimony?

8. Do the staff witnesses agree that total factor productivity growth tends to offset pure price inflation?

9. Do the staff witnesses agree that total factor productivity for 1991-2009 is approximately 1.4% per annum?

10. Do the witnesses agree that by including the parameter "equipment and software" the gross domestic private investment index indirectly recognizes productivity growth?

11. Is it correct that you assume that SAMDA measures which are primarily mitigative, rather than preventative, will result in little if any replacement power costs?

12. For example, if adding a specific piece of equipment, such as a pump, would not affect the frequency of core damage, but would mitigate the impact of a core damage event, that equipment would be considered mitigative rather than preventative, correct?

13. Hypothetically, is it possible that a preventative measure could reduce the duration of radioactive risks and thereby affect the duration of time that other units at the site are shut down? And if that were true, do you agree that failure to undertake the preventative SAMDA measure could increase the replacement power costs associated with a core damage event?

<u>Applicant Witnesses</u>

1. Do the witnesses agree that 2009 gas prices were historically low because of the impact of a major national recession that caused a decline in demand?

2. Do the witnesses agree that 2010 gas prices were also historically low?

3. Do the witnesses agree that gas prices are expected to increase faster than the rate of inflation as the economy recovers?

4. Do the witnesses agree that electricity prices in the ERCOT region are expected to increase faster than the rate of inflation as the economy recovers?

5. Do the witnesses agree that 2010 Texas power sales by NRG in the Houston and South zones of ERCOT is a reasonable benchmark for power costs in those regions?

6. Do the witnesses agree that in 2010 NRG generated and sold power at an average price of $68.39 per MWH?

7. Do the witnesses agree that the $68.39 per MWH price is substantially more than the approximately $37 per MWH price charged for balancing energy market prices in 2009 and 2010?

8. Do the witnesses agree that, assuming a 2020 commercial operation date for STP 3 & 4 implies that the relevant planning period for forecasting energy prices would extend to 2060?

9. Do the witnesses agree that applying Mr. Johnson's energy price methodology over a forty year operation span for STP 3 & 4 yields much higher real power prices than the 2008 balancing energy prices used as a sensitivity in the Applicant's testimony?

10. Do the witnesses agree that considering long-term price trends to determine escalation rates is a more reliable methodology that considers only one or two years?

11. Do the witnesses agree that the U.S. EIA 2001 Annual Energy Outlook projects a long-term 2.3% real escalation rate (above inflation) in natural gas spot prices at the Henry Hub?

12. Do the witnesses agree that ERCOT's Long Term Planning Task Force forecasts real ($2009) natural gas prices of $8.49 /mmbtu in 2030?

13. Do the witnesses agree that ERCOT's Long Term Planning Task Force forecasts real ($2009) natural gas prices to average $87.75 per MWH in 3030?

14. Do the witnesses agree that the February 2, 2011, loss of generation event in Texas caused a drop in responsive reserve capacity to 445 MWs?

15. Do the witnesses agree that the minimum responsive reserve capacity requirement in ERCOT is 2300 MW?

16. Do the witnesses agree that during the loss of generation event on February 2, 2011, that of the fifteen units ERCOT had contracted with to provide black start service, one unit did not start? And eight units tripped?

17. Do the witnesses agree that the loss of generation event on February 2, 2011,illustrates the possibility of loss of the grid if an STP forced outage occurred at the same time that other generating units incur forced outages caused by severe weather or other cause(s)?

18. Do the witnesses agree that ERCOT does not control or direct construction of generating capacity?

19. Do the witnesses agree that the Texas Public Utility Commission has brought numerous actions for market manipulation? And that many of these cases have been resolved by imposition of fines on generators?

20. Do the witnesses agree that the allegations of market manipulation brought by the PUC and payments of fines to resolve such, requires the acceptance of the possibility of the exercise of market power?

21. Do the witnesses agree that in 2005 Luminant paid a fine of $15 million to resolve allegations of market manipulation?

22. Do the witnesses agree that in circumstances of low reserve margins pivotal generators are able to charge higher prices compared to circumstances when reserve margins are not low?

23. Do the witnesses agree that labor costs vary by region?

24. Do the witnesses agree that in the affidavit filed in support of its motion for summary disposition that the lowest cost SAMDA was $158,000 ($2009)?

25. Do the witnesses agree that subsequent to its motion for summary disposition being denied it filed direct testimony (at pg. 63) that the lowest cost SAMDA is $982,500 ($2009)?

26. Do the witnesses agree that the $982,500 SAMDA cost contained in its direct testimony had not been used previously?

27. Is it correct that you assume that SAMDA measures which are primarily mitigative, rather than preventative, will result in little if any replacement power costs?

28. For example, if adding a specific piece of equipment, such as a pump, would not affect the frequency of core damage, but would mitigate the impact of a core damage event, that equipment would be considered mitigative rather than preventative, correct?

29. Hypothetically, is it possible that a preventative measure could reduce the duration of radioactive risks and thereby affect the duration of time that other units at the site are shut down? And if that were true, do you agree that failure to undertake the preventative SAMDA measure could increase the replacement power costs associated with a core damage event?

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Respectfully submitted,

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Intervenors' proposed additional cross-examination.

~~[illegible]~~

Do the witnesses agree that the primary cost justification to build + operate STP 3 + 4 is tied to the rising cost of natural gas?

ATTACHMENT 2

NRC Staff's Proposed Questions Regarding Contention CL-2

July 12, 2011

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
NUCLEAR INNOVATION NORTH	)	
AMERICA LLC	)	Docket Nos. 52-012 & 52-013
	)	
(South Texas Project, Units 3 & 4)	)	

NRC STAFF PROPOSED QUESTIONS

Pursuant to 10 C.F.R. § 2.1207(a)(3), the Atomic and Safety Licensing Board's (Board's) Initial Scheduling Order (October 20, 2009) (unpublished), and the Board's Memorandum and Order (Establishing Schedule for Evidentiary Hearing) (March 11, 2011) (unpublished), the staff of the U.S. Nuclear Regulatory Commission (Staff) hereby submits proposed questions for the Board to pose to the other parties' witnesses.

I. Proposed Questions Regarding Contention CL-2

A. Proposed Questions for Applicant Witness, Mr. Zimmerly, Regarding His Assessment of the Actual Risk-Reduction Potential of the SAMDAs

In his direct testimony, Mr. Zimmerly assumed that severe accident mitigation design alternative (SAMDA) 3d, Improved Bottom Head Penetration Design, would reduce the total core damage frequency (CDF) to zero. *See* Applicant CL-2 Direct Testimony at A54 & Table 3, pp. 24-26 (Ex. STP000011).[1] This assumption deserves further examination because the Staff concluded, based on the description of this SAMDA in the Advanced Boiling Water Reactor (ABWR) Technical Support Document, that SAMDA 3d was mitigative and, therefore, would not reduce CDF at all. *See* Staff CL-2 Direct Testimony at A13 & Table 3, pp. 15-18 (Ex. NRC000004). The objective of the following questions is to determine whether Mr.

[1] In the Applicant's and Staff's testimony, each question and answer is consecutively numbered, and citations to the Applicant's and Staff's testimony in this pleading are to answer numbers and page numbers. References to the Intervenors' testimony, on the other hand, are to page numbers.

Zimmerly agrees that the Staff more accurately accounted for the risk reduction potential of SAMDA 3d.

1. Mr. Zimmerly, your testimony accounts for the actual potential of each SAMDA to reduce risk based on the degree to which each SAMDA reduces core damage frequency, correct?
2. In concluding that SAMDA 3d, Improved Bottom Head Penetration Design, is the SAMDA that is closest to being cost-beneficial, did you assume that this SAMDA completely eliminates core damage frequency? Why did you make this assumption?
3. Do you agree that the Staff did not credit SAMDA 3d with reducing core damage frequency?
4. Do you also agree that Section A.5.3.4 on page 49 of the ABWR Technical Support Document (Ex. NRC00009B) states that SAMDA 3d, Improved Bottom Head Penetration Design, is "mitigative" and that "no credit for averted onsite costs applies?"
5. Given that the ABWR Technical Support Document considers SAMDA 3d to be mitigative, do you agree that giving SAMDA 3d no credit for reducing core damage frequency is more accurate than crediting SAMDA 3d with completely eliminating core damage frequency?
6. If SAMDA 3d were not credited with reducing core damage frequency, how would this affect your adjustment to SAMDA 3d's implementation cost? How would this affect the overall results of the SAMDA analysis?

B. Proposed Questions for Intervenors Witness, Mr. Johnson,
<u>On Accounting for the Actual Risk-Reduction Potential of the SAMDAs</u>

In his testimony, Mr. Johnson makes no attempt to account for the actual risk reduction potential of the SAMDAs, but instead assumes that each SAMDA completely eliminates severe accident risk. However, both the Staff's and Applicant's analyses considered the actual potential of the SAMDAs to reduce severe accident risk. This difference deserves further examination because the Staff's and Applicant's analyses agree that there is a large margin between implementation costs and total averted costs once actual risk reduction potentials are taken into account. The objective of the following questions is to determine whether Mr. Johnson agrees that if the Staff has appropriately accounted for the actual risk reduction potential of the SAMDAs, then there are no cost-beneficial SAMDAs even if Mr. Johnson's claims on other issues are assumed to be true.

1. Mr. Johnson, your analysis assumes that each SAMDA completely eliminates severe accident risk, correct?
2. Mr. Johnson, do you agree that in the Staff's and Applicant's analyses, both the Staff and the Applicant performed a more detailed analysis that examined the actual potential of each SAMDA to reduce severe accident risk? Do you further agree that both concluded that there was a large margin between SAMDA implementation costs and the costs that each SAMDA could actually avert?
3. On page 17 of your rebuttal testimony (Ex. INT000R. 45), you called for a "more robust review" of SAMDAs. Do you agree that the Applicant and Staff performed a more robust review by accounting for the actual risk-reduction potential of the SAMDAs rather than stopping at the initial screening analysis, which assumes that each SAMDA completely eliminates severe accident risk?
4. At what point would the more robust analysis you call for consider the actual risk-reduction potential of the SAMDAs?
5. In Answer 18 of the Staff's rebuttal testimony on pages 8-9 (Ex. NRC000058), the Staff stated that it incorporated your assumptions for inflation indexing, cost-of-living adjustment, and discount rate into its more detailed analysis and found that the SAMDA that is closest to being cost-beneficial has an implementation cost that is more than fourteen times greater than the actual risk it could avert. Do you agree

that if the Staff appropriately accounted for the actual risk-reduction potential of the SAMDAs in its more detailed analysis, then there are no cost-beneficial SAMDAs?

6. On page 17 of your rebuttal testimony (Ex. INT000R. 45), you state that the Applicant ought to perform a more up-to-date assessment of SAMDA implementation costs rather than inflating the costs in the ABWR Technical Support Document. Given that the costs in the ABWR Technical Support Document were intentionally biased on the low side, how would a current assessment of SAMDA costs potentially lead to a cost-beneficial SAMDA, especially given the sizable margins in the Applicant's and Staff's analyses once the actual risk-reduction potential of the SAMDAs are accounted for?[2]

C. Proposed Questions for Intervenors Witness,
Mr. Johnson, on Scaling SAMDA Costs for Inflation

In his rebuttal testimony, Mr. Johnson objected to the inflation index used by the Staff to scale SAMDA costs because it was not specific enough, but Mr. Johnson's chosen inflation index is more general than the Staff's. Mr. Johnson's objection to the Staff's inflation scaling index deserves further examination because it contradicts the approach he took in his own analysis. The objective of the following questions is to further explore this contradiction.

1. Mr. Johnson, on page 6 of your rebuttal testimony (Ex. INT000R. 45), you refer to the inflation index for scaling SAMDA costs that is favored by the Staff and state, "Perhaps the nonresidential structure component index would be appropriate for inflating the overall total costs of a plant or building." Do you agree that the Staff's choice of inflation index would be appropriate for inflating the overall total costs of a plant or building?

[2] Question B.6. pertains to a portion of Mr. Johnson's testimony that the Staff has proposed to exclude. If the Board excludes Mr. Johnson's testimony on the reassessment of SAMDA implementation costs, then the Staff withdraws its request to ask this question.

2. Mr. Johnson, you criticize the Staff's approach because, as you say on page 6 of your rebuttal testimony, "the Staff has not demonstrated that the individual SAMDA projects are composed of costs appropriately compared to the structures index." Is that correct?
3. However, if the Staff's inflation index is not reasonable because it is not specific enough to the SAMDAs, how can your chosen inflation index be reasonable for inflating SAMDA costs since it is even more general?
4. Can you explain why SAMDAs should not be considered part of the overall nuclear plant construction project?

D. Proposed Questions for Intervenors Witness, Mr. Johnson, Regarding the Weight to be Given to His Criticisms of the Economic Dispatch Model

In his testimony, Mr. Johnson raises several objections to the Applicant's economic dispatch model, even though he admits that he never tested it. Mr. Johnson's review of the economic dispatch model deserves further examination to determine what weight should be given to his objections to the model. The objective of the following questions is to show that his testimony on the dispatch model should not be given the same weight as the testimony of the Applicant (who created the model) and the Staff (who reviewed the model).

1. Mr. Johnson, your testimony contains several criticisms of the Applicant's economic dispatch model, correct?
2. On page 22 of your direct testimony (Ex. INT000021), did you state that the "realism" of the dispatch model "cannot be tested without a review of the model and software?"
3. However, did you also state on page 14 of your direct testimony that you did not review the Applicant's dispatch model?
4. Why did you not review the Applicant's economic dispatch model?

E. Proposed Questions for Intervenors Witness, Mr. Johnson, Regarding His Ultimate Position on the Staff's and Applicant's Assessment of the Economic Issues Raised by the Contention

In his testimony, Mr. Johnson makes several criticisms of statements made by the Applicant and Staff, but he does not ultimately state that the Applicant and Staff have unreasonably accounted for the economic factors raised by Contention CL-2, namely (1) using Electric Reliability Council of Texas (ERCOT) prices to account for replacement power costs, (2) accounting for market effects from all STP units shutting down, (3) accounting for consumer impacts from all STP units shutting down, (4) accounting for price spike impacts, and (5) accounting for grid outage impacts. Mr. Johnson's positions on these issues deserve further examination to determine whether there is any significant disagreement among the parties. The objective of the following questions is to show that there is, in fact, significant agreement among the parties that the Applicant and Staff have reasonably accounted for the economic factors raised in Contention CL-2.

1. Mr. Johnson, you agree that the Applicant and Staff have accounted for ERCOT prices in their analyses, correct?
   a. Do you agree that the Applicant and Staff have used 2008 ERCOT prices in their analyses?
   b. On page 11 of your rebuttal testimony (Ex. INT000R. 45) did you concede that you have accepted the use of 2008 ERCOT prices in the SAMDA analysis?
   c. Given this, do you assert that the Staff and Applicant have unreasonably incorporated ERCOT prices into their analyses by using 2008 ERCOT prices?
   d. If you contend that the Applicant's and Staff's use of 2008 ERCOT prices is unreasonable, please explain why using 2008 ERCOT prices is

unreasonable and explain, in quantitative terms, the significance of your disagreement with the Applicant and the Staff.

2. Mr. Johnson, you agree that the Applicant and Staff have accounted for market effects from all STP units shutting down, correct?
   a. Do you agree that the Staff, as explained in Answer 63 of its direct testimony on pages 51-53 (Ex. NRC000004), assessed market effects by calibrating the Applicant's economic dispatch model to, among other things, use 2008 ERCOT prices and a 9 percent capacity factor for wind?
   b. Do you agree that the Applicant, as explained in Answer 96 of its direct testimony on pages 49-50 (Ex. STP000011), calibrated its economic dispatch model to, among other things, use a 0 percent capacity factor for wind? Do you also agree that the Applicant, as explained in Answers 11 and 13 of its rebuttal testimony on pages 9-11 (Ex. STP000030), recalibrated its economic dispatch model to use 2008 ERCOT prices and still concluded that there are no cost-beneficial SAMDAs?
   c. Do you assert that the Staff and Applicant have unreasonably accounted for market effects?
   d. If you contend that the Applicant and Staff have unreasonably accounted for market effects, please explain how the Applicant's and Staff's methods are unreasonable and explain, in quantitative terms, the significance of your disagreement with the Applicant and the Staff.
3. Mr. Johnson, you agree that the Applicant and Staff have accounted for consumer impacts from all STP units shutting down, correct?
   a. Do you assert that the Staff and Applicant have unreasonably accounted for consumer impacts?

b. If you contend that the Applicant and Staff have unreasonably accounted for consumer impacts, please explain how the Applicant's and Staff's methods are unreasonable and explain, in quantitative terms, the significance of your disagreement with the Applicant and the Staff.

4. Mr. Johnson, you agree that the Applicant and Staff have accounted for price spike impacts in their analyses, correct?

   a. Do you agree that the Staff and Applicant accounted for an additional 20 percent impact from price spikes on marginal prices, above the 20 percent impact already embedded in the 2008 ERCOT marginal prices?

   b. Do you assert that the Staff and Applicant have unreasonably accounted for price spike impacts?

   c. If you contend that the Applicant and Staff have unreasonably accounted for price spike impacts, please explain how the Applicant's and Staff's methods are unreasonable and explain, in quantitative terms, the significance of your disagreement with the Applicant and the Staff.

5. Mr. Johnson, you agree that the Applicant and Staff have accounted for grid outages in their analyses, correct?

   a. Do you agree that the Applicant, in Answers 121 and 123 of its direct testimony on pages 61-63 (Ex. STP000011), assessed grid outage impacts by assuming a 10 percent probability of a grid outage occurring if a severe accident occurs at one of the proposed units? Do you also agree that the Applicant accounted for a $10 billion impact based on the 2003 Northeast blackout and, alternatively, a $45 billion impact based on economic damage from the 2000/2001 California energy crisis?

   b. Do you also agree that the Staff, in Answer 77 of its direct testimony on pages 58-59 (Ex. NRC000004), assessed grid outage impacts by assuming a 10 percent probability of a grid outage occurring if a severe accident occurs at one of the proposed units and assessing a $10 billion impact based on the 2003 Northeast blackout?

c. On page 12 of your direct testimony (Ex. INT000021), did you concede that the $10 billion impact from the 2003 Northeast blackout and the $45 billion impact from the 2000/2001 California energy crisis “may represent close to worst case examples?”

d. Given this, do you assert that the Staff and Applicant have unreasonably estimated impacts from grid outages in their analyses?

e. If you contend that the Applicant and Staff have unreasonably accounted for grid outage impacts, please explain why their methods are unreasonable and explain, in quantitative terms, the significance of your disagreement with the Applicant and the Staff.

6. Viewing the Applicant’s and Staff’s analyses in their totality, do you assert that they have unreasonably accounted for economic impacts from all STP units shutting down due to a severe accident at one of the STP units?

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Respectfully submitted,

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Dated at Rockville, Maryland
This 12th day of July 2011

NRC Staff Proposed Questions

1. Does the non-residential structures index cover the following aspects of SAMDA cost components: (1) design, (2) procurement, (3) installation, (4) procedures, (5) quality assurance, and (6) licensee activities for seeking regulatory approval?

2. Can you explain how core damage frequency is used in the Staff's refined analysis?

ATTACHMENT 3

Applicant’s Proposed Questions Regarding Contention CL-2

Confidential Pending Release by the Licensing Board
According to 10 C.F.R. § 2.1207(a)(3)(iii)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL
	)	52-013-COL
NUCLEAR INNOVATION NORTH AMERICA LLC	)	
	)	
(South Texas Project Units 3 and 4)	)	July 12, 2011

NUCLEAR INNOVATION NORTH AMERICA LLC'S PROPOSED QUESTIONS FOR THE BOARD ON INTERVENORS' DIRECT AND REBUTTAL TESTIMONY OF CLARENCE L. JOHNSON RELATED TO CONTENTION CL-2

Pursuant to 10 C.F.R. § 2.1207(a)(3), the U.S. Nuclear Regulatory Commission ("NRC") Atomic Safety and Licensing Board's ("Board's") Scheduling Order dated March 11, 2011, and the Board's Initial Scheduling Order dated October 20, 2009, Applicant Nuclear Innovation North America LLC ("NINA") hereby submits its proposed questions for the Board to consider propounding to Mr. Clarence L. Johnson at the evidentiary hearing regarding Contention CL-2. These questions are based on Mr. Johnson's direct and rebuttal testimony filed on May 9 and May 31, 2011, respectively, related to Contention CL-2.

Following the Board's guidelines for submittals of proposed questions for the Board to ask direct and rebuttal witnesses, this submittal provides a brief description of the issues that NINA contends need further examination, the objective of the examination, and the proposed line of questioning that may logically lead to achieving the objective.[1]

[1] *See* Initial Scheduling Order, at 16 (Oct. 20, 2009).

I. MR. JOHNSON'S FAILURE TO CALCULATE REPLACEMENT POWER COSTS

A. Brief Description of the Issue

Did Mr. Johnson perform any calculations of replacement power costs?

B. References

Johnson Direct Testimony (Exh. INT000021).

Johnson Rebuttal Testimony (Exh. INT000045).

C. Objective of the Examination

Demonstrate that Mr. Johnson has not performed any calculations of replacement power costs.

D. Proposed Line of Questioning

- Mr. Johnson, throughout your direct and rebuttal testimony, you make various comments and criticisms about the Applicant's and the NRC Staff's calculation of replacement power costs, including the assumptions made in those calculations.
    - Have you performed any calculations of your own that estimate the replacement power costs in the event of an STP outage, including the impact on consumers of outages of STP units, of price spikes, or of grid outages?

II. MR. JOHNSON'S EXPERTISE WITH NUCLEAR SAFETY ISSUES

A. Brief Description of the Issue

Does Mr. Johnson have sufficient qualifications to testify on issues related to nuclear safety?

B. References

Johnson Direct Testimony (Exh. INT000021) at 6, lines 1-7.

Johnson Direct Testimony (Exh. INT000021) at 14-15.

Johnson Rebuttal Testimony (Exh. INT000045) at 12, lines 13-18.

Johnson Rebuttal Testimony (Exh. INT000045) at 18, lines 1-12.

C. Objective of the Examination

Demonstrate that Mr. Johnson does not have sufficient qualifications to testify on nuclear safety issues, including the ramifications of the accident at the Fukushima power plant in Japan.

D. Proposed Line of Questioning

- Mr. Johnson, do you have an engineering degree?
- Do you have a degree in the physical sciences?
- Do you have any training in engineering or the physical sciences?
- Have you ever operated a nuclear power plant?
- Have you ever been employed at a nuclear power plant?
- Have you ever been employed to evaluate the safety or operation of nuclear power plants?
- Have you ever been employed in any capacity related to engineering or the physical sciences?
- On page 12 of your rebuttal testimony, lines 13-18, you refer to the potential for a common mode failure, such as a natural disaster, to cause a severe accident.
    - Do you know what the probability of such an event is?
    - Have you ever evaluated such a probability?

III. IMPLICATIONS OF FUKUSHIMA ACCIDENT

A. Brief Description of the Issue

Does Mr. Johnson have any basis for his opinions related to the implications of the accident at the Fukushima power plant in Japan?

B. References

Johnson Direct Testimony (Exh. INT000021) at 6, lines 1-7.

Johnson Direct Testimony (Exh. INT000021) at 14, lines 18-22, and 15, lines 1-8.

Johnson Rebuttal Testimony (Exh. INT000045) at 18, lines 1-12.

C. Objective of the Examination

Demonstrate that Mr. Johnson has no basis for his opinions regarding the ramifications of the accident at Fukushima.

D. Proposed Line of Questioning

- Mr. Johnson, on page 6, lines 3-4, and pages 14 and 15 of your direct testimony, you state that the accident at Fukushima likely will result in the permanent shutdown of all six nuclear units at the site.
    - Did Units 5 and 6 experience a core melt?
    - Did Units 5 and 6 experience a hydrogen explosion?
    - Did Units 5 and 6 experience any significant damage?
    - Is there any physical reason why those units could not be restarted?
    - Did Units 1 through 4 each experience a partial core melt?
    - Did Units 1 through 4 each experience a hydrogen explosion?
    - Do you agree that Units 1 through 4 likely will not restart due to the extensive physical damage at each of those reactors?
- On page 18 of your rebuttal testimony, you refer to "CDR" on lines 5, 8, and 11. What does CDR refer to?
- Referring to your statement on page 18 of your rebuttal testimony, lines 4-6, do you know whether a mitigation measure could reduce damage at a co-located unit or reduce the duration of the shutdowns at the co-located units?
    - Have you performed any analysis of this issue?

- Referring to your statement on page 18 of your rebuttal testimony, lines 6-8, do you know whether the Fukushima accident affects the evaluation of Severe Accident Mitigation Design Alternatives ("SAMDAs")? If yes:
  - Which SAMDA would be affected?
  - How would the evaluation of that SAMDA be affected?
- What is the basis for your statement that the "CDR" of Fukushima is in the range of 10^{-6}?

IV. GRID OUTAGES

A. <u>Brief Description of the Issue</u>

Has Mr. Johnson overestimated the costs of a grid outage?

B. <u>References</u>

Johnson Direct Testimony (Exh. INT000021) at 12, lines 6-15.

Exhs. INT000032, INT000033, and INT000036.

C. <u>Objective of the Examination</u>

Demonstrate that Mr. Johnson has overestimated the cost of grid outages.

D. <u>Proposed Line of Questioning</u>

- Mr. Johnson, on page 12 of your direct testimony, lines 6-8, you state that the combination of high prices and rolling blackouts in California in 2000-2001 produced economic damage in the range of $45 billion, citing *The California Energy Crisis: Causes and Policy Option* as the basis for your figure.
  - Are excerpts from that report provided in Exhibit INT000036?
  - Do pages 3-4 of that report actually state that the cost was conservatively $40 to $45 billion?
  - Does the bottom of page 3 of that report state that $40 billion of the total amount was attributable to factors other than the blackouts?

  - Do pages 3-4 of that report indicate that only $0 to $5 billion was attributable to blackouts and reductions in economic growth?

- Mr. Johnson, on page 12 of your direct testimony, lines 9 through 11, you state that the Northeast blackout of 2003 caused $10 billion in damages.
  - Do you agree that Exhibits INT000032 and INT000033 show that the damage was less - - $7 to $10 billion according to the second page of Exhibit INT000033, and $4.5 to $8.2 billion according to the first page of Exhibit INT000032?
  - Do you also agree that the top of the second page of Exhibit INT000032 shows that the Department of Energy ("DOE") published a total cost estimate of $6 billion for the Northeast blackout?

- On page 12 of your direct testimony, lines 13-15, you state that damage to industrial and commercial customers can be significant, with values as high as $50,000 to $1 million per customer for an hour of outage. You cite the report entitled *The Economic Impacts of the August 2003 Blackout* as support.
  - Is that report Exhibit INT000033?
  - Can you tell me where those figures appear in that Exhibit?
  - Do you agree that the Exhibit itself does not contain those figures?

V. ESCALATION RATES FOR SAMDAs

A. Brief Description of the Issue

Is use of the Consumer Price Index conservative?

B. References

Johnson Direct Testimony (Exh. INT000021) at 15-17.

Johnson Rebuttal Testimony (Exh. INT000045) at 6-9.

C. Objective of the Examination

Demonstrate that the use of the Consumer Price Index is conservative for escalating the costs of SAMDAs from 1991 dollars to current dollars.

D. Proposed Line of Questioning

- Mr. Johnson, does the rate of escalation of costs of goods and services vary depending upon the good or service in question?
- Since 1991, have the costs of construction escalated more rapidly than the rate of inflation as determined by the Consumer Price Index? by the Core Personal Consumption Expenditures price index?
- Since 1991, have the costs of manufactured components, such as pumps and valves, escalated more rapidly than the rate of inflation as determined by the Consumer Price Index? by the Core Personal Consumption Expenditures price index?
- On page 6 of your rebuttal testimony, lines 20-22, you suggest that the use of the Equipment and Software component of the Gross Domestic Product ("GDP") private non-residential fixed investment index may be more appropriate to use for SAMDAs.
    - Can you describe the alternatives that are included within the SAMDAs?
    - Have you reviewed the Advanced Boiling Water Reactor ("ABWR") Technical Support Document, which is Exhibit NRC00009A and NRC00009B?
    - Does the ABWR Technical Support Document provide a description of the SAMDAs?
    - Do you agree that SAMDAs would in general be an integral part of a nuclear power plant?

  - Does the definition of Equipment and Software provided by the Bureau of Economic Analysis exclude components that are installed as part of a nuclear power plant?
    - In particular, I refer you to Exhibit NRC000022, page 6-3, the second row on equipment and software, and the second column which provides a definition of Equipment and Software. Does the last entry for that box explicitly state that Equipment and Software does not include "equipment that are integral parts of structures"?
    - Furthermore, if you look on that same page at the first row, do you agree that equipment that is an integral part of a structure is considered to be part of the Structure part of the index, not the Equipment and Software part?
- On page 6 of your rebuttal testimony, lines 9-11, you state that the non-residential structure component of the GDP implicit price deflator represents "an extreme outlier from other general inflation measures."
  - Is that statement made in the context of the rate of inflation of the overall economy?
  - Does your statement apply to the rate of inflation for non-residential structures?
  - Do you agree that the non-residential structure component of the GDP implicit price deflator is appropriate to use for costs of construction of non-residential buildings?

VI. PRICE SPIKES AND MARKET POWER

A. <u>Brief Description of the Issue</u>

Do price spikes account for increases in prices due to scarcity of supply?

B. References

Johnson Rebuttal Testimony (Exh. INT000045) at 14-15.

C. Objective of the Examination

Demonstrate that Mr. Johnson's allegations regarding price spikes account for increases in prices due to scarcity of supply.

D. Proposed Line of Questioning

- Mr. Johnson, on pages 14-15 of your rebuttal testimony, you discuss the impacts of market power. In particular, starting on page 14, line 21, you state that "shortage situations allow pivotal generators to charge higher prices than they would in normal supply conditions."
- During price spikes, are generators able to receive revenue above and beyond their marginal costs due to scarcity of supply?
- Therefore, do you agree that price spikes account for higher prices during shortage conditions?

VII. COSTS OF REPLACEMENT POWER

A. Brief Description of the Issue

Has Mr. Johnson provided a misleading discussion of STP replacement power costs?

B. References

Johnson Rebuttal Testimony (Exh. INT000045) at 9-12.

Exhs. INT000046, INT000050, and INT000055.

C. Objective of the Examination

Demonstrate that Mr. Johnson has provided a misleading discussion of STP replacement power costs.

D. <u>Proposed Line of Questioning</u>

- On page 10 of your rebuttal testimony, lines 3-5 and footnote 6, you calculate the average cost of electricity from NRG's 2010 Annual Report and SEC Form 10-K by taking NRG's total operating revenues ($3.057 billion) and dividing it by its total net generation (44.7 million MWh), and arriving at an average cost of $68.39 per MWh.
    - Mr. Johnson, did you provide excerpts from NRG's 2010 Annual Report as Exhibit INT000050?
    - Other than the excerpted pages, did you read the entire report?[2]
    - Are you aware that NRG has operating revenues from sources other than the sale of electricity that it generates? For example:
        - Does page 15 of INT000050 state that, in addition to Energy Revenues of $2.85 billion in Texas, NRG also had various other revenues, such as capacity revenues, that combine to form the total of $3.057 billion that you cite?
        - Am I correct that your calculation did not take that into account?
        - Additionally, are you aware that the Energy Revenues are not solely due to the sale of electricity from NRG plants?
            - For example, does page 54 of the Form 10-K state that Energy Revenue includes revenues from the settlement of financial instruments?

[2] This report is accessible at http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDE4MTcwfENoaWxkSUQ9NDMxMDMwfFR5cGU9MQ==&t=1. Excerpts from this report are enclosed as Attachment 1.

        - Does page 117 of the Form 10-K indicate that Energy Revenue includes revenues from the resale of purchase power?
        - Am I correct that your calculation did not take that into account?
    - Do you agree that, if you had taken these factors into account, your calculated prices of electricity would have been lower than $68.39 per MWh?
    - Additionally, are you aware that the Energy Revenues not only accounts for sales on the ERCOT market, but also bilateral sales? [Refer to page 54 of the Form 10-K]
    - Therefore, is it correct to say that it is not possible to determine the cost of power on the ERCOT market by dividing the Energy Revenues by the total megawatt-hours generated by NRG plants in Texas?

- Mr. Johnson, on page 10 of your rebuttal testimony, lines 19-21, you state that if your methodology for calculating electricity prices were extended out to 2060, it would produce much higher real prices than the 2008 ERCOT prices.
    - Are you aware of any governmental agency that calculates electricity prices for the year 2060?
    - Are there many variables that could materially affect electricity prices in 2060?
    - Is there substantial uncertainty regarding any estimate of prices 50 years into the future?
    - Do you know of any reliable estimates of electricity prices 50 years into the future?

- Mr. Johnson, on page 11 of your rebuttal testimony, lines 15-17, you opine that the long-term price of natural gas is likely to increase because it is a finite resource?
    - Do additional reserves of natural gas continue to be discovered?
    - Are the net proven reserves actually increasing?
        - Are you aware that the U.S. Energy Information Administration ("EIA") has determined that natural gas reserves increased by about 50% from 2004 to 2009?[3]
    - Do improvements in technology, such as fracking, enable more known sources of natural gas to be economically developed that previously were not economical?
    - Therefore, do you agree that, even though natural gas may be a finite resource, there may be increases in the amount of natural gas that can be economically recovered?
- Mr. Johnson, on page 11 of your rebuttal testimony, lines 20-22, you state that the EIA projects a long-term escalation rate of 2.3% for natural gas spot prices at the Henry Hub.
    - Is that information provided on Exhibit INT000046?
    - Does Exhibit INT000046 also provide a long-term escalation rate of 1.3% for natural gas as delivered to electrical power plants?
    - Do you agree that the cost of natural gas as delivered to electrical plants, not the cost at Henry Hub, is the cost of interest for determining replacement power costs?

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[3] *See* http://www.eia.gov/dnav/ng/ng_enr_sum_dcu_NUS_a.htm, which is enclosed as Attachment 2.

- Mr. Johnson, on page 12 of your rebuttal testimony, you also cite to ERCOT's Long Term Planning Task Force "Process Overview and Interim Results" for the proposition that the marginal price of electricity will be $87.75 per MWh in 2030.
  - Is that document Exhibit INT000055?
  - Is the figure of $87.75 for a situation in which there is no production tax credit for wind power?
  - Is there currently a production tax credit for wind power?
  - You only provided excerpts from the ERCOT document, and did not provide page 11 of that report.[4]
    - Does page 11 of that document show that the price of electricity will be $78.55 per MWh in 2030, assuming that there will continue to be production tax credits for wind power?
    - Do you know whether these costs are in 2010 dollars or 2030 dollars?
      - Given the large increase in costs from 2010 to 2030, do you agree that these figures are likely in 2030 dollars?

VIII. IMPACTS OF LABOR ON SAMDA COSTS

A. Brief Description of the Issue

Do labor costs make any significant difference to the costs of SAMDAs?

B. References

Johnson Rebuttal Testimony (Exh. INT000045) at 15, lines 13-14.

Exh. NRC00009B.

[4] This report is available at http://www.ercot.com/content/meetings/lts/keydocs/2011/0503/Interim%20BAU%20Generation%20Expansion_Rev1.pdf and is enclosed as Attachment 3.

C. Objective of the Examination

Demonstrate that there is no basis for Mr. Johnson's claim that labor costs will make a difference to the costs of SAMDAs.

D. Proposed Line of Questioning

- Mr. Johnson, on page 15 of your rebuttal testimony, lines 13-14, you state that local labor costs will be incurred for installing SAMDAs and that salary and wage rates vary with region.
    - Mr. Johnson, do you know whether the SAMDAs would incur any additional labor to install than the design specified in the ABWR Design Control Document?
    - If there is any additional labor, do you know whether the labor would be a significant portion of the overall cost of the SAMDA?

IX. RELATIONSHIP OF SAMDA COSTS TO SCREENING EVALUATION

A. Brief Description of the Issue

What is the relationship between SAMDA costs and the screening evaluation?

B. References

Johnson Rebuttal Testimony (Exh. INT000045) at 15-18.

C. Objective of the Examination

Demonstrate that the cost of a SAMDA is unaffected by whether the SAMDA passes through the screening evaluation.

D. Proposed Line of Questioning

- Mr. Johnson, on pages 15 though 18 of your rebuttal testimony, you argue that the Applicant should revise the cost of the SAMDAs as provided in the ABWR Technical Support Document, because certain SAMDAs no longer can be screened out.

- Is it true that the SAMDAs cannot be screened out because of an increase in the replacement power costs and market effects of an outage of the STP units?
- Do you agree that the costs of SAMDAs are not affected by the replacement power costs and market effects of an outage?

X. INTERVENORS' SURPRISE REGARDING RISK-REDUCTION OF SAMDAs

A. Brief Description of the Issue

Did the Applicant surprise the Intervenors by evaluating the risk-reduction achieved by SAMDAs?

B. References

Johnson Rebuttal Testimony (Exh. INT000045) at 15-18.

C. Objective of the Examination

Demonstrate that the Intervenors should not have been surprised when the Applicant evaluated the risk-reduction to be achieved by individual SAMDAs.

D. Proposed Line of Questioning

- Mr. Johnson, on pages 15-16 of your rebuttal testimony, you state that the Applicant changed the "lowest cost SAMDA" from $158,000 to $982,500.
    - Do you agree that the Applicant does not categorize the SAMDA costing $982,500 as the "lowest cost" SAMDA?
    - Do you agree that the direct testimony of Zimmerly and Pieniazek, on page 27, categorizes that SAMDA as the "lowest risk-adjusted cost" SAMDA?
    - Do you agree that the "lowest cost" SAMDA and the "lowest risk-adjusted cost" SAMDA refer to two different concepts?

- Mr. Johnson, on page 17, lines 10-12, you state that the Applicant's analysis of risk-reduction to be achieved by individual SAMDAs "does not permit intervenors to effectively respond to a fundamentally different analysis."
  - Mr. Johnson, are you claiming that you were surprised by the Applicant's analysis of risk-reduction?
    - Did you read Section 7.3 of the Environmental Report, which is part of Exhibit STP000013?
    - Are you aware that Environmental Report Section 7.3.1 states that SAMDAs which are not screened out are evaluated to determine their risk-reduction?
    - Additionally, did you read the Licensing Board's decision in LBP-11-07 (pages 3-4), dated February 28, 2011, ruling on the motion for summary disposition on Contention CL-2?
    - Are you aware that Judge Arnold's dissenting opinion in LBP-11-07 discusses that the Applicant would, if needed, account for risk-reduction to demonstrate that there are no cost-effective SAMDAs?
    - Therefore, do you agree that the Applicant clearly indicated that it would evaluate the risk-reduction to be achieved by SAMDAs that did not pass the screening test?
  - Mr. Johnson, does Section A.4 of the ABWR Technical Support Document (Exhibit NRC00009B) discuss the risk-reductions to be achieved by the SAMDAs?

- Did the Applicant and NRC staff use the risk-reduction factors from the ABWR Technical Support Document?
- Is the Technical Support Document dated 1994?
- Are you aware that the Applicant distributed the Technical Support Document to the Intervenors during the oral argument on October 21, 2010? [Reference Tr. 1041-1042]
- Therefore, do you agree that the Intervenors had the risk-reduction factors used by the Applicant and NRC staff for more than a half year prior to submitting your testimony?

XI. DC TIES TO ERCOT

A. Brief Description of the Issue

Does Mr. Johnson understate the amount of power available from outside of ERCOT through use of DC ties?

B. References

Johnson Direct Testimony (Exh. INT000021) at 8, lines 3-5.

C. Objective of the Examination

Demonstrate that Mr. Johnson has understated the amount of power available from outside of ERCOT through use of DC ties?

D. Proposed Line of Questioning

- Mr. Johnson, on page 8 of your direct testimony, lines 3-5, you state that "ERCOT assumes, for reserve margin planning purposes, that only 400 MW of capacity from outside the region are available through these [DC] interconnections."
  - I would like to refer you to Exhibit STP000007, which is ERCOT's "Report on the Capacity, Demand, and Reserves in the ERCOT Region" (December 2010).

Does page 7 of that report show that ERCOT assumes 553 MW from the DC ties for purposes of determining the reserve margin?

Respectfully submitted,

Signed (electronically) by Steven P. Frantz
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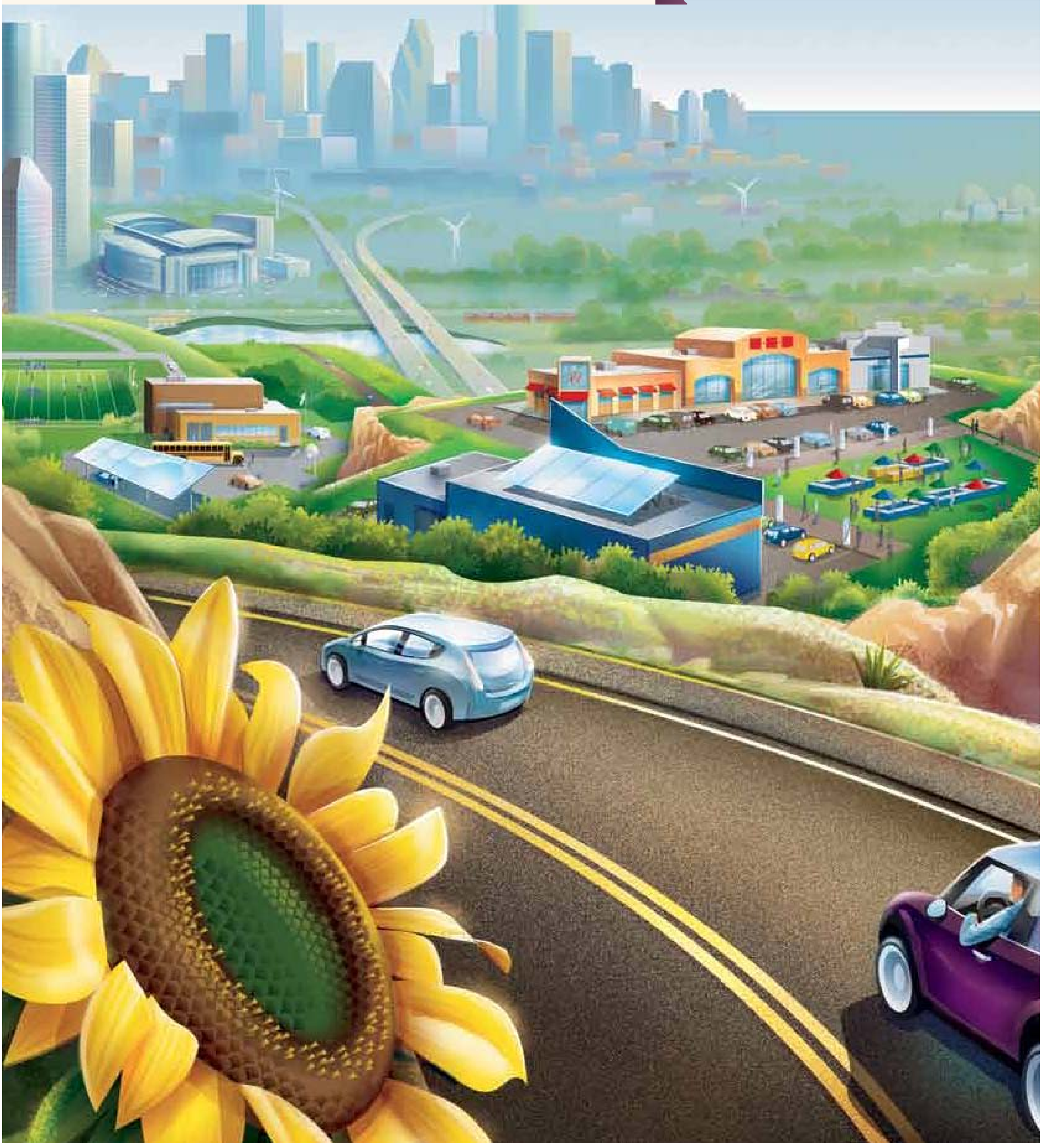
Counsel for Nuclear Innovation North America LLC

Dated in Washington, D.C.
this 12th day of July 2011

ATTACHMENT 1

MOVING CLEAN ENERGY FORWARD

NRG 2010 ANNUAL REPORT



Item 6 — Selected Financial Data

The following table presents NRG's historical selected financial data. The data included in the following table has been recast to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations as well as the retroactive effect of the two-for-one stock split effective May 25, 2007. For additional information refer to Item 15 — Note 4, *Discontinued Operations and Dispositions*, to the Consolidated Financial Statements.

This historical data should be read in conjunction with the Consolidated Financial Statements and the related notes thereto in Item 15 and Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In millions except ratios and per share data)				
Statement of income data:					
Total operating revenues	$ 8,849	$ 8,952	$ 6,885	$ 5,989	$ 5,585
Total operating costs and expenses	8,119	7,283	5,119	5,073	4,724
Income from continuing operations, net	476	941	1,053	556	539
Income from discontinued operations, net	—	—	172	17	78
Net income attributable to NRG Energy, Inc.	$ 477	$ 942	$ 1,225	$ 573	$ 617
Common share data:					
Basic shares outstanding — average	252	246	235	240	258
Diluted shares outstanding — average	254	271	275	288	301
Shares outstanding — end of year	247	254	234	237	245
Per share data:					
Income attributable to NRG from continuing operations — basic	$ 1.86	$ 3.70	$ 4.25	$ 2.09	$ 1.89
Income attributable to NRG from continuing operations — diluted	1.84	3.44	3.80	1.90	1.76
Net income attributable to NRG — basic	1.86	3.70	4.98	2.16	2.19
Net income attributable to NRG — diluted	1.84	3.44	4.43	1.96	2.02
Book value	$ 32.65	$ 29.72	$ 26.75	$ 19.55	$ 19.60
Business metrics:					
Cash flow from operations	$ 1,623	$ 2,106	$ 1,479	$ 1,517	$ 408
Liquidity position [(a)]	$ 4,660	$ 3,971	$ 4,124	$ 2,715	$ 2,227
Ratio of earnings to fixed charges	2.00	3.27	3.65	2.24	2.36
Ratio of earnings to fixed charges and preference dividends	1.96	3.04	3.19	1.99	2.08
Return on equity	5.91%	12.24%	17.20%	10.38%	10.85%
Ratio of debt to total capitalization	42.94%	43.49%	47.50%	55.58%	57.18%
Balance sheet data:					
Current assets	$ 7,137	$ 6,208	$ 8,492	$ 3,562	$ 3,083
Current liabilities	4,220	3,762	6,581	2,277	2,032
Property, plant and equipment, net	12,517	11,564	11,545	11,320	11,546
Total assets	26,896	23,378	24,808	19,274	19,436
Long-term debt, including current maturities, capital leases, and funded letter of credit	10,511	8,418	8,161	8,346	8,698
Total stockholders' equity	$ 8,072	$ 7,697	$ 7,123	$ 5,519	$ 5,686

(a) Liquidity position is determined as disclosed in Item 7, *Liquidity and Capital Resources, Liquidity Position*. It includes funds deposited by counterparties of $408 million, $177 million and $754 million as of December 31, 2010, 2009, and 2008, respectively, which represents cash held as collateral from hedge counterparties in support of energy risk management activities. It is the Company's intention to limit the use of these funds for repayment of the related current liability for collateral received in support of energy risk management activities.

The following table provides the details of NRG's operating revenues:

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In millions)				
Energy	$2,854	$3,726	$4,408	$4,349	$1,770
Capacity	824	1,023	1,343	1,175	1,516
Retail revenue	5,277	4,440	—	—	—
Mark-to-market activities	(136)	(290)	525	(77)	295
Other revenue	30	53	609	542	2,004
Total operating revenues	$8,849	$8,952	$6,885	$5,989	$5,585

Energy revenue consists of revenues received from third parties for sales in the day-ahead and real-time markets, as well as bilateral sales. Energy revenues also included revenues from the settlement of financial instruments.

Capacity revenue consists of revenues received from a third party at either the market or negotiated contract rates for making installed generation capacity available in order to satisfy system integrity and reliability requirements. Capacity revenues also included revenues from the settlement of financial instruments. In addition, capacity revenue includes revenue received under tolling arrangements, which entitle third parties to dispatch NRG's facilities and assume title to the electrical generation produced from that facility.

Retail revenue, representing operating revenues of Reliant Energy and Green Mountain Energy, consists of revenues from retail electric sales to residential, small business, commercial, industrial and governmental/institutional customers, as well as revenues from the sale of excess supply into various markets in Texas.

Mark-to-market activities includes fair value changes of economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges and trading activities.

Other revenue includes the following components:

- Thermal revenue consists of revenues received from the sale of steam, hot and chilled water generally produced at a central district energy plant and sold to commercial, governmental and residential buildings for space heating, domestic hot water heating and air conditioning. It also includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process.

- Contract amortization revenues consists of acquired power contracts, gas swaps, and certain power sales agreements assumed at Fresh Start and Texas Genco purchase accounting dates related to the sale of electric capacity and energy in future periods, which are amortized into revenue over the term of the underlying contracts based on actual generation or contracted volumes. Also included is amortization of the intangible asset for net in-market C&I contracts that was established in connection with the acquisition of Reliant Energy.

- Hedge Reset is the impact from the net settlement of long-term power contracts and gas swaps by negotiating prices to current market. This transaction was completed in November 2006.

- Other revenue also consists of operations and maintenance fees, or O&M fees, construction management services, or CMA fees, sale of natural gas and emission allowances, and revenue from ancillary services. O&M fees consist of revenues received from providing certain unconsolidated affiliates with services under long-term operating agreements. CMA fees are earned where NRG provides certain management and oversight of construction projects pursuant to negotiated agreements such as for the GenConn and Cedar Bayou 4 construction projects. Ancillary services are comprised of the sale of energy-related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products.

Note 1 — Nature of Business

General

NRG Energy, Inc., or NRG or the Company, is primarily a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is engaged in: the ownership, development, construction and operation of power generation facilities; the transacting in and trading of fuel and transportation services; the trading of energy, capacity and related products in the United States and select international markets; and the supply of electricity, energy services, and cleaner energy and carbon offset products to retail electricity customers in deregulated markets through its retail subsidiaries Reliant Energy and Green Mountain Energy.

As of December 31, 2010, NRG had a total global generation portfolio of 193 active operating fossil fuel and nuclear generation units, at 45 power generation plants, with an aggregate generation capacity of approximately 24,570 MW, and approximately 265 MW under construction which includes partner interests of 120 MW. In addition to its fossil fuel plant ownership, NRG has ownership interests in operating renewable facilities with an aggregate generation capacity of 470 MW, consisting of four wind farms representing an aggregate generation capacity of 450 MW, a 20 MW solar facility and less than 5 MW of distributed solar. Within the United States, NRG has large and diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 23,565 MW of fossil fuel and nuclear generation capacity in 185 active generating units at 43 plants. The Company's power generation facilities are most heavily concentrated in Texas (approximately 10,745 MW, including 450 MW from four wind farms), the Northeast (approximately 6,900 MW), South Central (approximately 4,125 MW), and West (approximately 2,150 MW, including 20 MW from a solar facility) regions of the United States. Through certain foreign subsidiaries, NRG has investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity. In addition, NRG has approximately 115 MW of additional generation capacity from the Company's thermal assets, as well as a district energy business that has a steam and chilled water capacity of approximately 1,140 megawatts thermal equivalent, or MWt.

Reliant Energy and Green Mountain Energy arrange for the transmission and delivery of electricity to customers, bill customers, collect payments for electricity sold and maintain call centers to provide customer service. Based on metered locations, as of December 31, 2010, Reliant Energy and Green Mountain Energy combined serve approximately 1.9 million residential, small business, commercial and industrial customers.

NRG was incorporated as a Delaware corporation on May 29, 1992. NRG's common stock is listed on the New York Stock Exchange under the symbol "NRG". The Company's headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. NRG's telephone number is (609) 524-4500. The address of the Company's website is *www.nrgenergy.com*. NRG's recent annual reports, quarterly reports, current reports, and other periodic filings are available free of charge through the Company's website.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the U.S., or U.S. GAAP. The FASB Accounting Standards Codification, or ASC, is the source of authoritative U.S. GAAP recognized by the Financial Accounting Standards Board, or FASB, to be applied by nongovernmental entities. In addition, the rules and interpretative releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants.

The consolidated financial statements include NRG's accounts and operations and those of its subsidiaries in which the Company has a controlling interest. All significant intercompany transactions and balances have been eliminated in consolidation. The usual condition for a controlling financial interest is ownership of a majority of the voting interests of an entity. However, a controlling financial interest may also exist through arrangements that do not involve controlling voting interests. As such, NRG applies the guidance of ASC 810, *Consolidations,* or ASC 810, to determine when an entity that is insufficiently capitalized or not controlled through its voting interests, referred to as a variable interest entity or VIE, should be consolidated.

Prior to January 1, 2010, ASC 810 required a quantitative analysis of the economic risk/rewards of a VIE to determine the party, referred to as the primary beneficiary, that is required to consolidate the VIE. Under this analysis, the primary beneficiary absorbed a majority of the expected losses of the VIE, received the majority of the expected residual returns of the VIE, or both. In December 2009, the FASB issued ASU No. 2009-17*, Consolidations: Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, or ASU 2009-17. This guidance, effective for NRG as of January 1, 2010, now specifies that a qualitative analysis be performed, requiring the primary beneficiary to have both the power to direct the activities of a VIE that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. In determining the primary beneficiary, NRG thoroughly evaluates the VIE's design, capital structure, and relationships among variable interest holders. NRG will not consolidate a VIE in which it has a majority ownership interest when the Company is not considered the primary beneficiary. The Company's adoption of ASU 2009-17 on January 1, 2010, did not have an impact on its results of operations, financial position, or cash flows. NRG determined that one of its equity method investments, Sherbino I Wind Farm LLC, or Sherbino, was a VIE as of January 1, 2010, upon adoption of this new guidance. NRG owns a 50% interest in Sherbino but the Company is not the primary beneficiary under the amended guidance. Therefore, NRG will continue to account for its investment in Sherbino under the equity method. For further discussion see Note 16 — *Investments Accounted for by the Equity Method.*

In February 2010, the FASB issued ASU No. 2010-10, *Consolidation (Topic 810): Amendments for Certain Investment Funds*, or ASU 2010-10. The amendments to ASC 810 clarify that related parties should be considered when evaluating the criteria for determining whether a decision maker's or service provider's fee represents a variable interest. In addition, the amendments clarify that a quantitative calculation should not be the sole basis for evaluating whether a decision maker's or service provider's fee represents a variable interest. The Company adopted the provisions of ASU 2010-10 effective January 1, 2010, with no impact on its results of operations, financial position or cash flows.

Upon its emergence from bankruptcy on December 5, 2003, the Company qualified for and adopted fresh start reporting, or Fresh Start, under ASC 852, *Reorganizations*, or ASC 852.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with an original maturity of three months or less at the time of purchase.

Funds Deposited by Counterparties

Funds deposited by counterparties consist of cash held by NRG as a result of collateral posting obligations from the Company's counterparties with positions in NRG's hedging program. These amounts are segregated into separate accounts that are not contractually restricted but, based on the Company's intention, are not available for the payment of NRG's general corporate obligations. Depending on market fluctuations and the settlement of the underlying contracts, the Company will refund this collateral to the hedge counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company's balance sheet, with an offsetting liability for this cash collateral received within current liabilities. Changes in funds deposited by counterparties are closely associated with the Company's operating activities, and are classified as an operating activity in the Company's consolidated statements of cash flows.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within the Company's projects that are restricted in their use. These funds are used to pay for current operating expenses and current debt service payments, per the restrictions of the debt agreements.

Trade Receivables and Allowance for Doubtful Accounts

Trade receivables are reported in the balance sheet at outstanding principal adjusted for any write-offs and the allowance for doubtful accounts. For its Reliant Energy and Green Mountain Energy businesses, the Company accrues an allowance for doubtful accounts based on estimates of uncollectible revenues by analyzing counterparty credit ratings (for commercial and industrial customers), historical collections, accounts receivable aging and other factors. These businesses write-off accounts receivable balances against the allowance for doubtful accounts when it determines a receivable is uncollectible.

Inventory

Inventory is valued at the lower of weighted average cost or market, unless evidence indicates that the weighted average cost will be recovered with a normal profit in the ordinary course of business, and consists principally of fuel oil, coal and raw materials used to generate electricity or steam. The Company removes these inventories as they are used in the production of electricity or steam. Spare parts inventory is valued at a weighted average cost, since the Company expects to recover these costs in the ordinary course of business. The Company removes these inventories when they are used for repairs, maintenance or capital projects. Sales of inventory are classified as an operating activity in the consolidated statements of cash flows.

Property, Plant and Equipment

Property, plant and equipment are stated at cost; however impairment adjustments are recorded whenever events or changes in circumstances indicate that their carrying values may not be recoverable. NRG also classifies nuclear fuel related to the Company's 44% ownership interest in STP as part of the Company's property, plant, and equipment. Significant additions or improvements extending asset lives are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation other than nuclear fuel is computed using the straight-line method, while nuclear fuel is amortized based on units of production over the estimated useful lives. Certain assets and their related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in cost of operations in the consolidated statements of operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with ASC 360. An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value with the difference recorded in operating costs and expenses in the statements of operations. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with ASC 323, which requires that a loss in value of an investment that is other than a temporary decline should be recognized. The Company identifies and measures losses in the value of equity method investments based upon a comparison of fair value to carrying value.

Discontinued Operations

Long-lived assets or disposal groups are classified as discontinued operations when all of the required criteria specified in ASC 360 are met. These criteria include, among others, existence of a qualified plan to dispose of an asset or disposal group, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. In addition, upon completion of the transaction, the operations and cash flows of the disposal group must be eliminated from ongoing operations of the Company, and the disposal group must not have any significant continuing involvement with the Company. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

Project Development Costs and Capitalized Interest

Project development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, Board of Director approval pursuant to a formal project plan that subjects the Company to significant future obligations that can only be discharged by the use of a Company asset.

Interest incurred on funds borrowed to finance capital projects is capitalized, until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2010, 2009, and 2008, was $36 million, $37 million, and $45 million, respectively.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis which approximates the effective interest method over the term of the related debt.

Intangible Assets

Intangible assets represent contractual rights held by NRG. The Company recognizes specifically identifiable intangible assets including customer contracts, customer relationships, energy supply contracts, trade names, emission allowances, and fuel contracts when specific rights and contracts are acquired. In addition, NRG also established values for emission allowances and power contracts upon adoption of Fresh Start reporting. These intangible assets are amortized based on expected volumes, expected delivery, expected discounted future net cash flows, straight line or units of production basis.

Intangible assets determined to have indefinite lives are not amortized, but rather are tested for impairment at least annually or more frequently if events or changes in circumstances indicate that such acquired intangible assets have been determined to have finite lives and should now be amortized over their useful lives. NRG had no intangible assets with indefinite lives recorded as of December 31, 2010.

Emission allowances held-for-sale, which are included in other non-current assets on the Company's consolidated balance sheet, are not amortized; they are carried at the lower of cost or fair value and reviewed for impairment in accordance with ASC 360.

Goodwill

In accordance with ASC 350, the Company recognizes goodwill for the excess cost of an acquired entity over the net value assigned to assets acquired and liabilities assumed.

NRG performs goodwill impairment tests annually, during the fourth quarter, and when events or changes in circumstances indicate that the carrying value may not be recoverable. Goodwill impairment is determined using a two step process:

Step one — Identify potential impairment by comparing the fair value of a reporting unit to the book value, including goodwill. If the fair value exceeds book value, goodwill of the reporting unit is not considered impaired. If the book value exceeds fair value, proceed to step two.

Step two — Compare the implied fair value of the reporting unit's goodwill to the book value of the reporting unit goodwill. If the book value of goodwill exceeds fair value, an impairment charge is recognized for the sum of such excess.

Income Taxes

NRG accounts for income taxes using the liability method in accordance with ASC 740, *Income Taxes*, or ASC 740, which requires that the Company use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

NRG has two categories of income tax expense or benefit — current and deferred, as follows:

- Current income tax expense or benefit consists solely of regular tax less applicable tax credits, and
- Deferred income tax expense or benefit is the change in the net deferred income tax asset or liability, excluding amounts charged or credited to accumulated other comprehensive income.

NRG reports some of the Company's revenues and expenses differently for financial statement purposes than for income tax return purposes resulting in temporary and permanent differences between the Company's financial statements and income tax returns. The tax effects of such temporary differences are recorded as either deferred income tax assets or deferred income tax liabilities in the Company's consolidated balance sheets. NRG measures the Company's deferred income tax assets and deferred income tax liabilities using income tax rates that are currently in effect. A valuation allowance is recorded to reduce the Company's net deferred tax assets to an amount that is more-likely-than-not to be realized.

The Company accounts for uncertain tax positions in accordance with ASC 740, which applies to all tax positions related to income taxes. Under ASC 740, tax benefits are recognized when it is more-likely-than-not that a tax position will be sustained upon examination by the authorities. The benefit from a position that has surpassed the more-likely-than-not threshold is the largest amount of benefit that is more than 50% likely to be realized upon settlement. The Company recognizes interest and penalties accrued related to uncertain tax benefits as a component of income tax expense.

In accordance with ASC 805 and as discussed further in Note 19, *Income Taxes*, any reductions after January 1, 2009, to existing net deferred tax assets or valuation allowances or changes to uncertain tax benefits, as they relate to Fresh Start or previously completed acquisitions, have been recorded to income tax expense rather than additional paid-in capital or goodwill.

Revenue Recognition

Energy — Both physical and financial transactions are entered into to optimize the financial performance of NRG's generating facilities. Electric energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in the Company's consolidated statements of operations. Financial transactions, or the buying and selling of energy for trading purposes, are recorded net within operating revenues in the consolidated statements of operations in accordance with ASC 815, *Derivatives and Hedging*, or ASC 815.

Capacity — Capacity revenues are recognized when contractually earned, and consist of revenues billed to a third party at either the market or a negotiated contract price for making installed generation capacity available in order to satisfy system integrity and reliability requirements.

Sale of Emission Allowances — NRG records the Company's bank of emission allowances as part of the Company's intangible assets. From time to time, management may authorize the transfer of emission allowances in excess of usage from the Company's emission bank to intangible assets held-for-sale for trading purposes. NRG records the sale of emission allowances on a net basis within other revenue in the Company's consolidated statements of operations.

Contract Amortization — Assets and liabilities recognized from power sales agreements assumed at Fresh Start and through acquisitions related to the sale of electric capacity and energy in future periods for which the fair value has been determined to be significantly less (more) than market are amortized to revenue over the term of each underlying contract based on actual generation and/or contracted volumes.

Retail revenues — Gross revenues for energy sales and services to retail customers are recognized upon delivery under the accrual method. Energy sales and services that have been delivered but not billed by period end are estimated. Gross revenues also includes energy revenues from resales of purchased power, which were $158 million for the year ended December 31, 2010 and $251 million for the eight-month period ended December 31, 2009. These revenues represent a sale of excess supply to third parties in the market.

As of December 31, 2010, and 2009, NRG recorded unbilled revenues of $282 million and $308 million, respectively, for retail energy sales and services. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Volume estimates are based on daily forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

Cost of Energy for Retail Operations

The cost of energy for electricity sales and services to retail customers is based on estimated supply volumes for the applicable reporting period. A portion of the cost of energy ($61 million and $69 million as of December 31, 2010, and 2009, respectively) consisted of estimated transmission and distribution charges not yet billed by the transmission and distribution utilities. In estimating supply volumes, the Company considers the effects of historical customer volumes, weather factors and usage by customer class. Transmission and distribution delivery fees are estimated using the same method used for electricity sales and services to retail customers. In addition, ERCOT ISO fees are estimated based on historical trends, estimated supply volumes and initial ERCOT ISO settlements. Volume estimates are then multiplied by the supply rate and recorded as cost of operations in the applicable reporting period.

Derivative Financial Instruments

NRG accounts for derivative financial instruments under ASC 815, which requires the Company to record all derivatives on the balance sheet at fair value unless they qualify for a NPNS exception. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either:

- Recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments; or
- Deferred and recorded as a component of accumulated OCI until the hedged transactions occur and are recognized in earnings.

NRG's primary derivative instruments are power sales contracts, fuels purchase contracts, other energy related commodities, and interest rate instruments used to mitigate variability in earnings due to fluctuations in market prices and interest rates. On an ongoing basis, NRG assesses the effectiveness of all derivatives that are designated as hedges for accounting purposes in order to determine that each derivative continues to be highly effective in offsetting changes in fair values or cash flows of hedged items. Internal analyses that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such an energy contract designated as a hedge. If it is determined that the derivative instrument is not highly effective as a hedge, hedge accounting will be discontinued prospectively. Hedge accounting will also be discontinued on contracts related to commodity price risk previously accounted for as cash flow hedges when it is probable that delivery will not be made against these contracts. In this case, the gain or loss previously deferred in accumulated OCI would be immediately reclassified into earnings. If the derivative instrument is terminated, the effective portion of this derivative in accumulated OCI will be frozen until the underlying hedged item is delivered.

Revenues and expenses on contracts that qualify for the NPNS exception are recognized when the underlying physical transaction is delivered. While these contracts are considered derivative financial instruments under ASC 815, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception, the fair value of the related contract is recorded on the balance sheet and immediately recognized through earnings.

NRG's trading activities are subject to limits in accordance with the Company's Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of NRG's foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of the Company's statements of operations for the period, but are accumulated and reported as a separate component of stockholders' equity until sale or complete or substantially complete liquidation of the net investment in the foreign entity takes place. Foreign currency transaction gains or losses are reported within other income/(expense) in the Company's statements of operations. For the years ended December 31, 2010, 2009, and 2008, amounts recognized as foreign currency transaction gains (losses) were immaterial. The Company's cumulative translation adjustment balances as of December 31, 2010, 2009, and 2008 were $76 million, $79 million and $58 million, respectively.

Concentrations of Credit Risk

Financial instruments which potentially subject NRG to concentrations of credit risk consist primarily of cash, trust funds, accounts receivable, notes receivable, derivatives, and investments in debt securities. Cash and cash equivalents and funds deposited by counterparties are predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt. Trust funds are held in accounts managed by experienced investment advisors. Certain accounts receivable, notes receivable, and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables and other contractual arrangements are subject to collateral requirements under the terms of enabling agreements. However, NRG believes that the credit risk posed by industry concentration is offset by the diversification and creditworthiness of the Company's customer base. See Note 5, *Fair Value of Financial Instruments,* for a further discussion of derivative concentrations.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, funds deposited by counterparties, trust funds, receivables, accounts payables, and accrued liabilities approximate fair value because of the short-term maturity of these instruments. The carrying amounts of long-term receivables usually approximate fair value, as the effective rates for these instruments are comparable to market rates at year-end, including current portions. Any differences are disclosed in Note 5, *Fair Value of Financial Instruments*. The fair value of long-term debt is based on quoted market prices for those instruments that are publicly traded, or estimated based on the income approach valuation technique for non-publicly traded debt. For the years ended December 31, 2010, 2009, and 2008, the Company recorded an unrealized gain of $2 million, an unrealized gain of $3 million, and impairment charges of $23 million, respectively, related to an investment in commercial paper. In 2010, the Company recognized a $3 million gain on the sale of part of the investment. As of December 31, 2010, the net carrying value of the remaining investment was $8 million.

ATTACHMENT 2

U.S. Energy Information Administration

NATURAL GAS

OVERVIEW DATA ANALYSIS & PROJECTIONS GLOSSARY › FAQS ›

Natural Gas Reserves Summary as of Dec. 31

(Billion Cubic Feet, unless otherwise noted)

Area: U.S. **Period:** Annual

Show Data By: Data Series / Area	2004	2005	2006	2007	2008	2009	View History
Dry Natural Gas	192,513	204,385	211,085	237,726	244,656	272,509	1925-2009
Natural Gas, Wet After Lease Separation	201,200	213,308	220,416	247,789	255,035	283,879	1979-2009
Natural Gas Nonassociated, Wet After Lease Separation	173,551	185,072	190,776	215,121	226,012	250,496	1979-2009
Natural Gas Associated-Dissolved, Wet After Lease Separation	27,649	28,236	29,640	32,668	29,023	33,383	1979-2009
Natural Gas Liquids (Million Barrels)	7,928	8,165	8,472	9,143	9,275		1979-2008

- = No Data Reported; **--** = Not Applicable; **NA** = Not Available; **W** = Withheld to avoid disclosure of individual company data.

Notes: Miscellaneous States includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee. See Definitions, Sources, and Notes link above for more information on this table.

Release Date: 12/30/2010
Next Release Date: 12/30/2011

ATTACHMENT 3

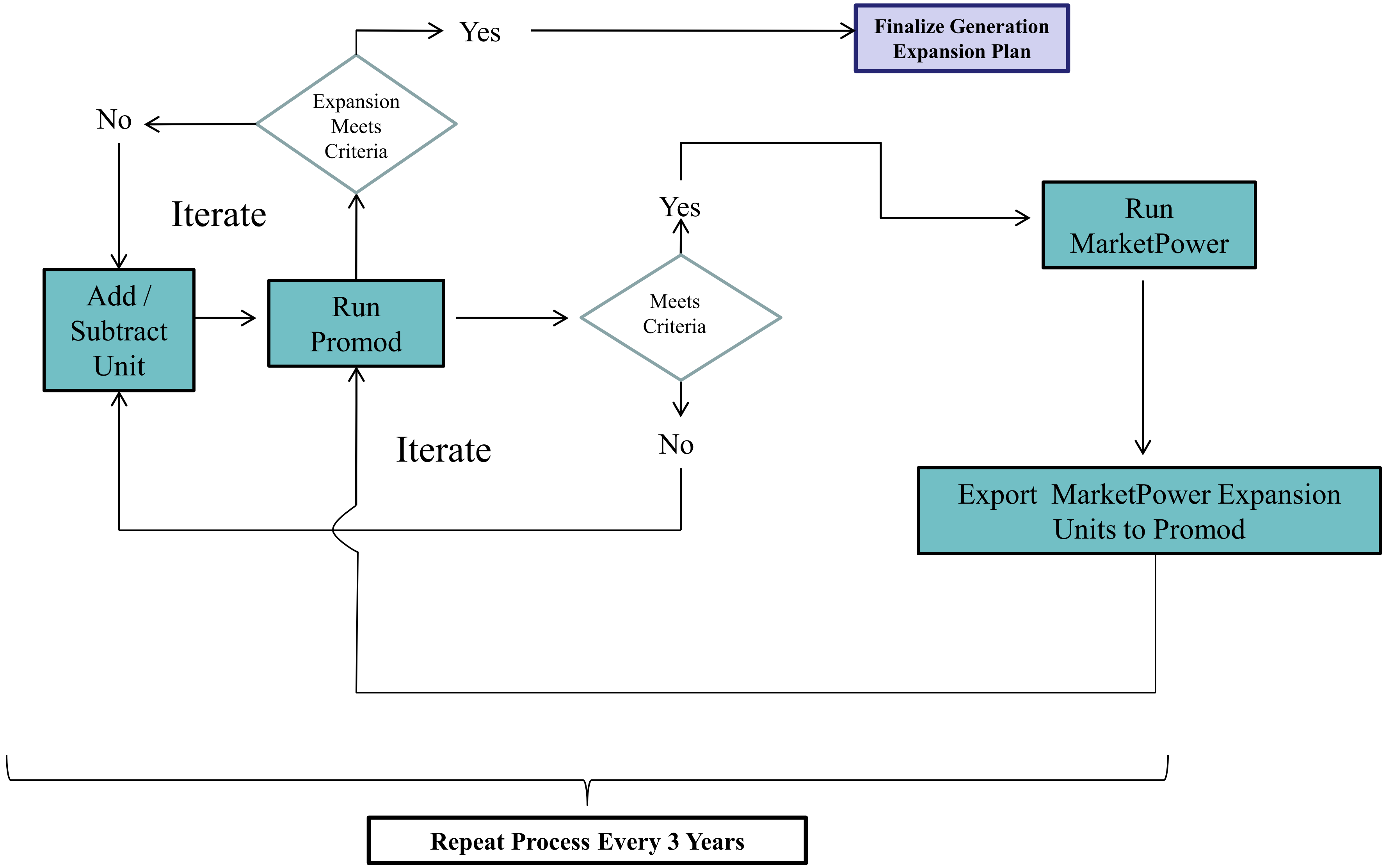
Process Overview
and
Interim Results Discussion

May 2011

Agenda

- **Process Overview**
- **BAU Scenario**
  - Interim Generation Expansion Results
    - No PTC
    - With PTC
  - Sensitivities
    - High Natural Gas Price (EIA plus $5/mmbtu)
    - High Natural Gas Price with PTC

Flowchart of Process



Financial Criteria

- **Start with input assumptions (from Generic Database Characteristics spreadsheet)**
- **Model uses financial accounting metrics to calculate net cash flows**
- **Revenue for year 1 results from Promod run**
  - Promod captures hourly LMP's against hourly generation of the unit
  - Revenue from 1 year Promod run is then escalated for future years by respective change in natural gas price
    - Assumption: natural gas remains the marginal fuel
    - This is to develop a forecasted stream of revenues over the life of the project
      - Annual Revenue: natural gas price x market heat rate x generation of unit
- **Determined a Net Present Value (NPV) of the project from the net cash flows**
- **Calculated the Internal Rate of Return from the NPV**
  - The project had to meet a 16% threshold

Model / Process Considerations

- **These results are intended to show how directional changes in the model inputs affect the generation development results.**
- **Several items/model updates could have significant impact on results:**
  - Inclusion of incremental ancillary service requirements and revenues (where applicable due to differences in resource characteristics)
  - Enforcing reserve margin of 13.75%
  - Inclusion of scarcity pricing during spinning reserves use

Expansion Results

BAU Expansion Plan Results

Additions in 2014 are units with I/As:

- Coal: Sandy Creek (925 MW)
- Wind: Archer-Young, Gunsight Mtn., Penascal, Senate, Sherbino Mesa (872 MW)

Total economic expansion builds in 2030:

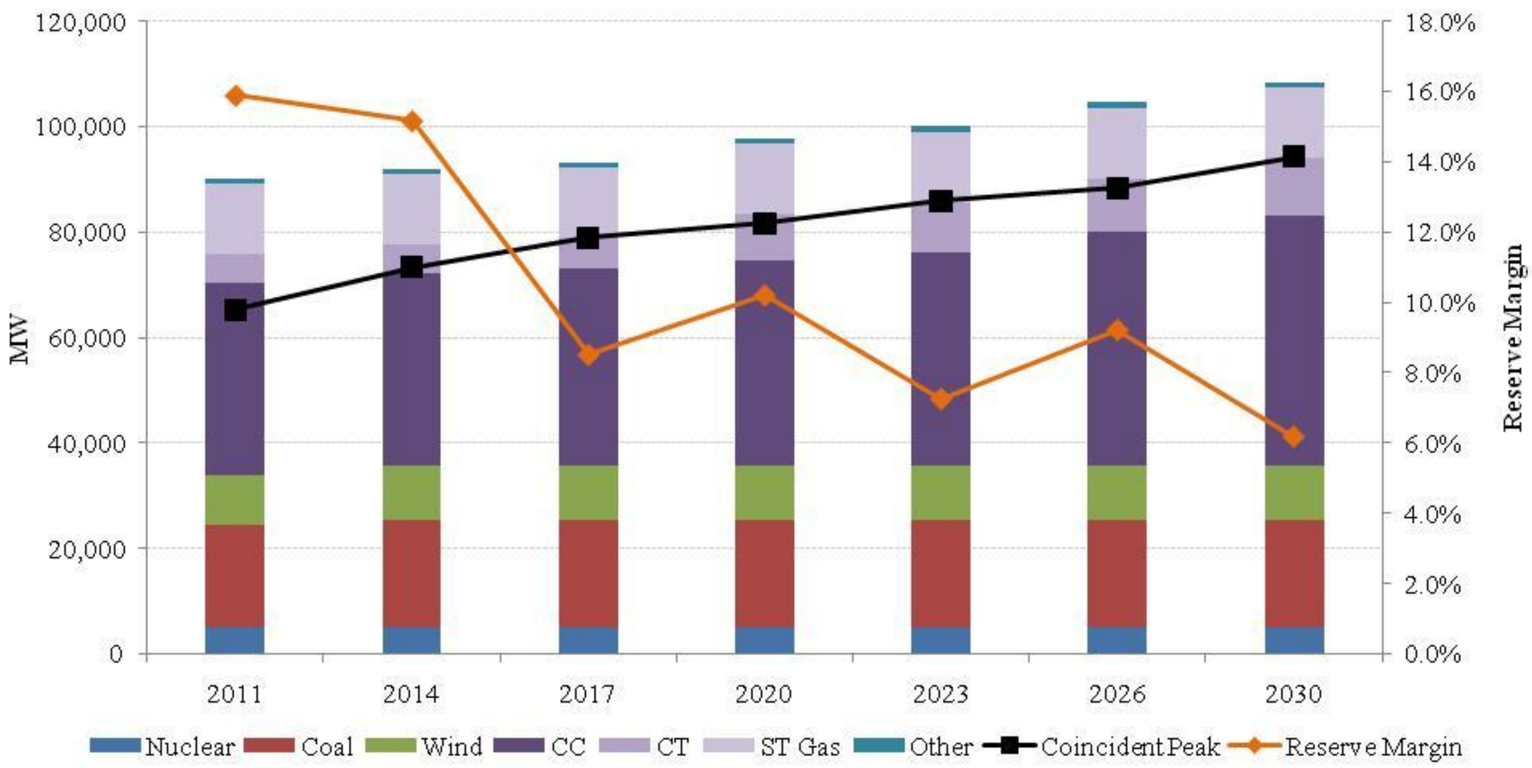
- 27 combined cycles – 10,800 MWs
- 57 combustion turbines – 5,700 MWs
- Total thermal additions – 16,500 MWs

Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	800	1,600	1,600	4,000	2,800
CT Adds	MW			-	400	3,000	700	500	1,100
Coal Adds	MW			925	-	-	-	-	-
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			872	-	-	-	-	-
Annual Capacity Additions	MW			1,797	1,200	4,600	2,300	4,500	3,900
Cumulative Capacity Additions	MW			1,797	2,997	7,597	9,897	14,397	18,297
Reserve Margin	%	21.4	15.9	15.2	8.5	10.2	7.2	9.2	6.2
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	42.51	56.76	63.23	73.69	81.50	87.75
Natural Gas Price	$/mmbtu	4.38	4.50	4.63	5.10	5.68	6.47	7.35	8.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	9.18	11.14	11.14	11.38	11.09	10.46
Natural Gas Generation	%	38.2	41.3	45.8	47.0	49.3	51.0	53.0	59.3
Coal Generation	%	39.5	37.8	36.5	34.3	33.0	31.7	30.6	31.4
Wind Generation	%	7.8	9.2	7.3	8.4	8.0	7.7	7.4	7.6
Scarcity Hours	HRS	-	-	-	29	33	42	49	56
Unserved Energy	GWhs	-	-	-	24.1	39.9	63.9	60.1	68.8

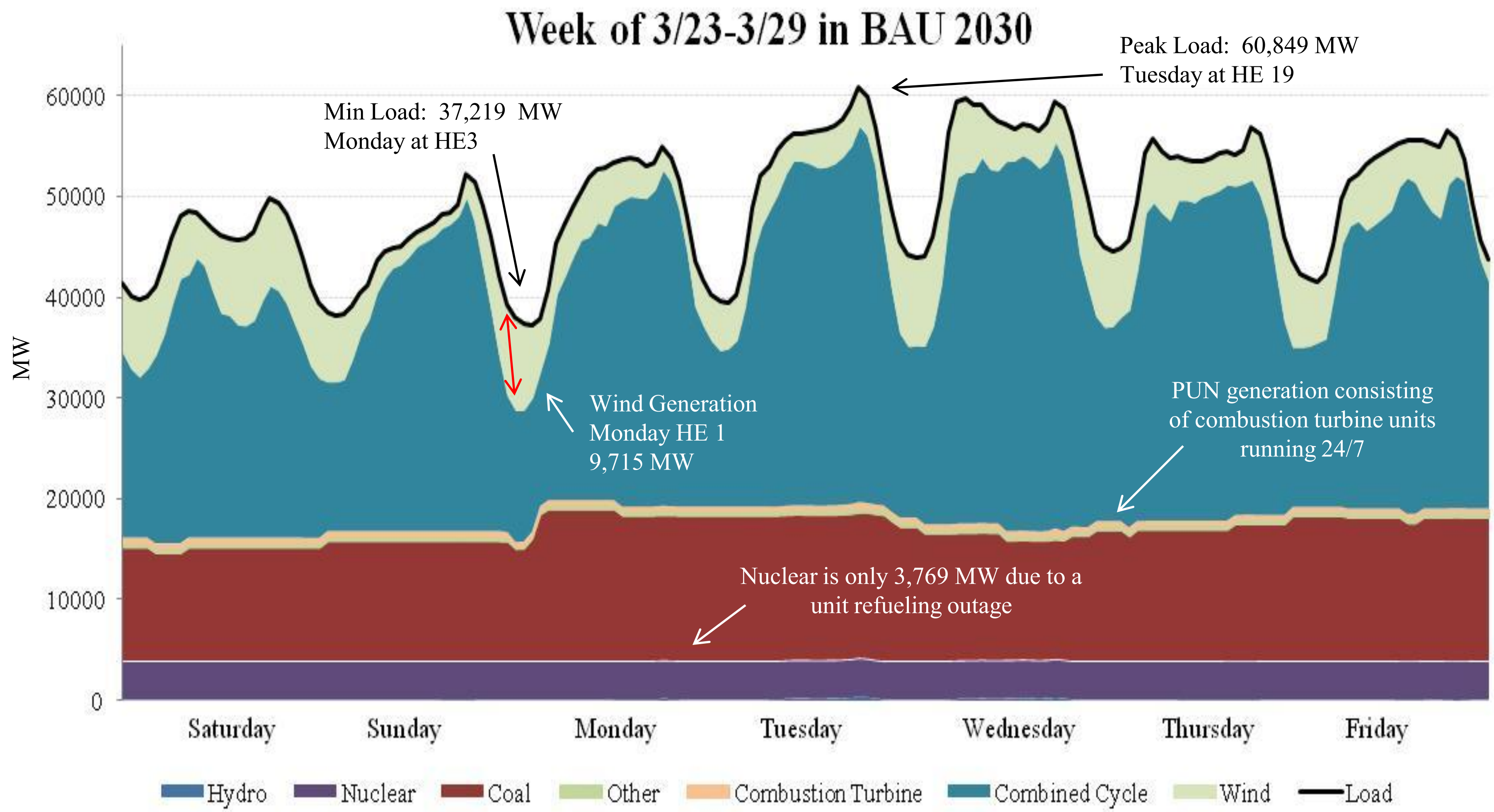
Capacity and Coincident Peak Changes: BAU

2030 capacity by fuel type:

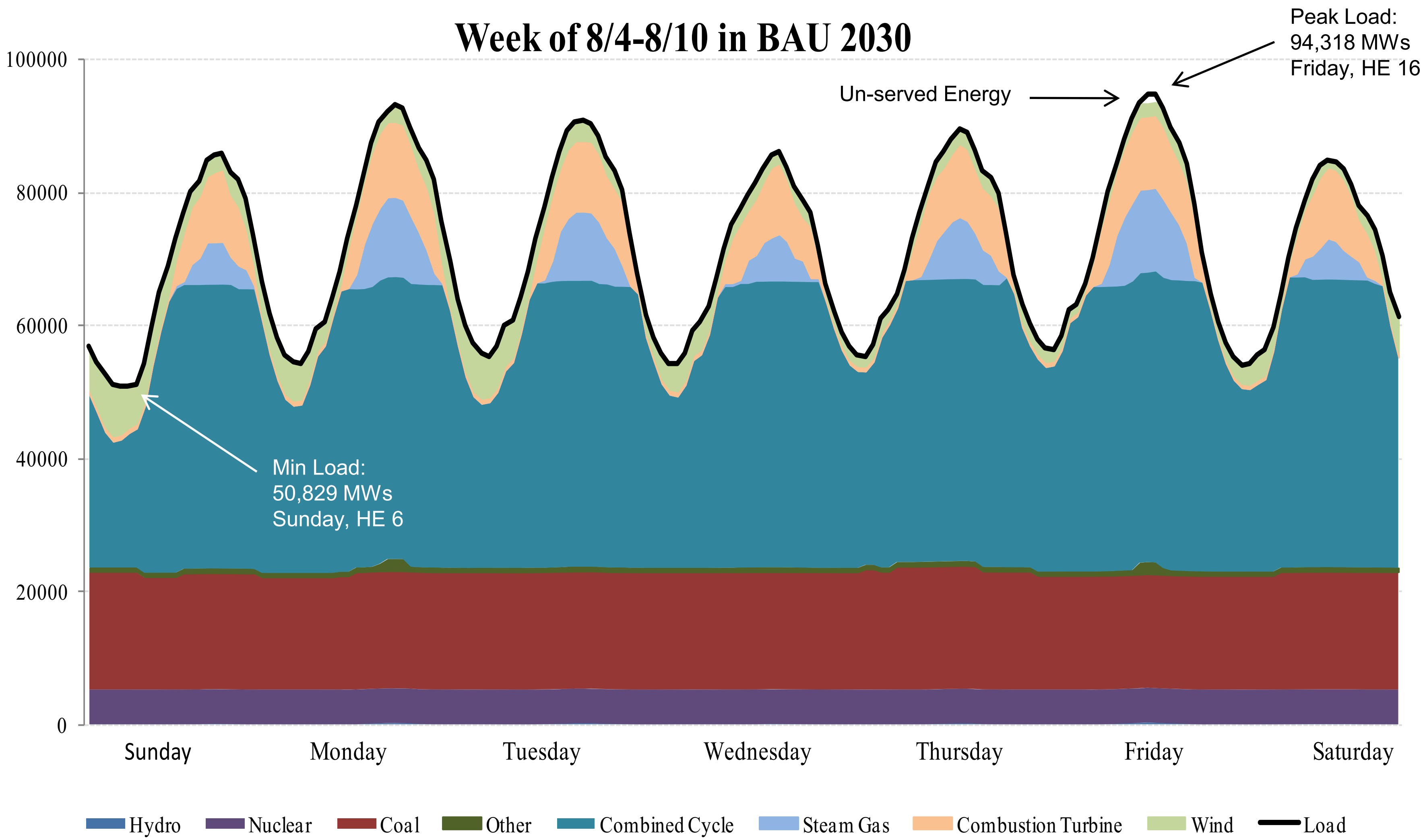
- 65% Natural gas
- 19% Coal
- 5% Nuclear
- 10% Wind
- 1% Other – Hydro, Biomass, and LFG



Weekly Generation Pattern



Weekly Generation Pattern



BAU with PTC Expansion Plan Results

Total economic wind expansion MWs by 2030:

- 25,250 MWs; total wind on entire system – 35,600 MWs

Total economic thermal expansion builds in 2030:

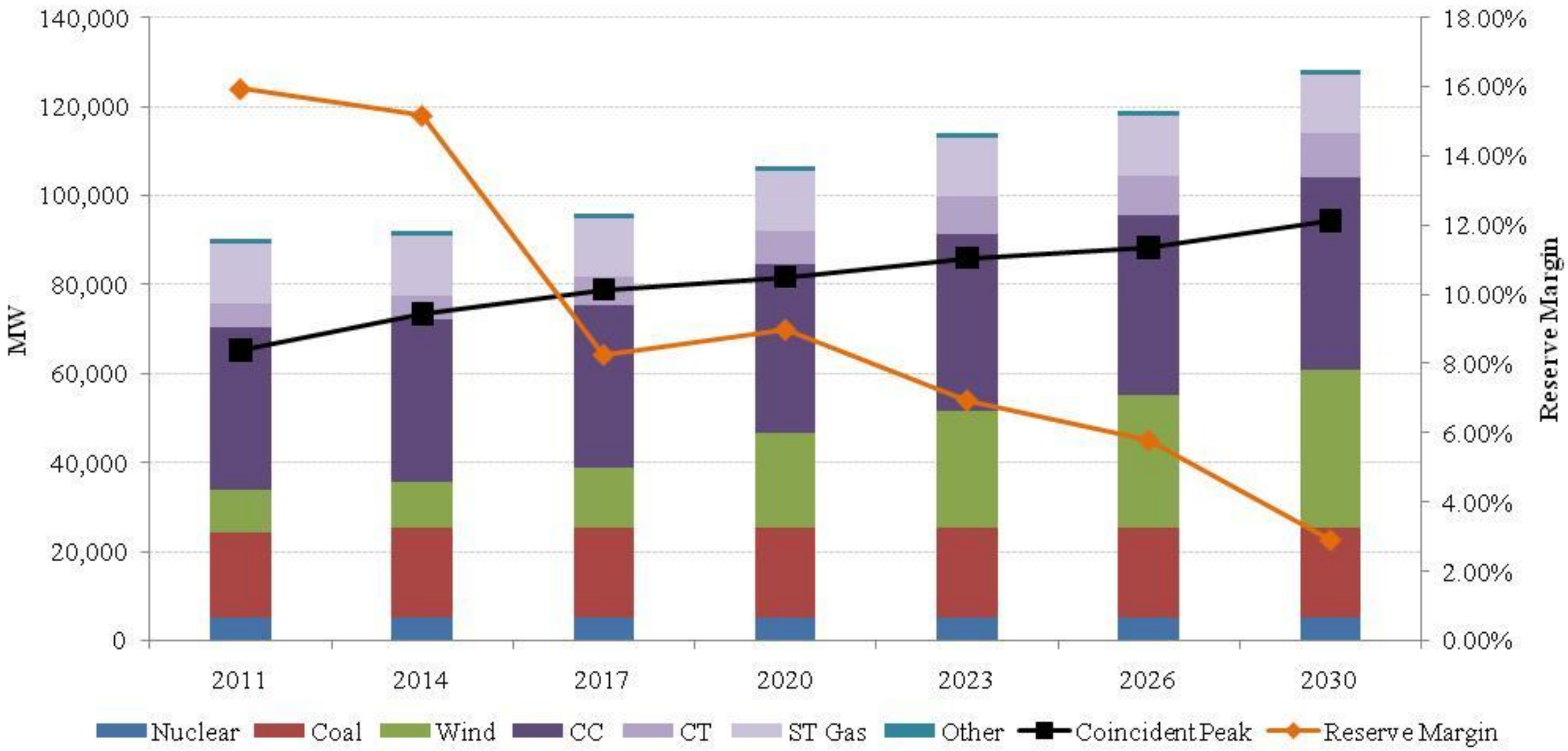
- 17 combined cycles – 6,800 MWs
- 42 combustion turbines – 4,200 MWs
- Total thermal additions – 11,000 MWs

Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	-	1,600	1,600	800	2,800
CT Adds	MW			-	700	1,500	1,000	500	500
Coal Adds	MW			925	-	-	-	-	-
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			872	3,250	7,500	5,000	3,500	6,000
Annual Capacity Additions	MW			1,797	3,950	10,600	7,600	4,800	9,300
Cumulative Capacity Additions	MW			1,797	5,747	16,347	23,947	28,747	38,047
Reserve Margin	%	21.4	15.9	15.2	8.3	9.0	6.9	5.8	2.9
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	42.51	57.86	66.85	67.00	73.68	78.55
Natural Gas Price	$/mmbtu	4.38	4.50	4.63	5.10	5.68	6.47	7.35	8.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	9.18	11.35	11.77	10.36	10.02	9.36
Natural Gas Generation	%	38.2	41.3	45.8	40.7	41.6	40.4	40.3	39.3
Coal Generation	%	39.5	37.8	36.5	34.2	32.3	30.6	29.2	27.3
Wind Generation	%	7.8	9.2	7.3	11.0	16.5	19.7	21.5	24.6
Scarcity Hours	HRS	-	-	-	32	52	37	40	37
Unserved Energy	GWhs	-	-	-	36.2	88.3	60.7	75.9	92.8

Capacity and Coincident Peak Changes: BAU with PTC

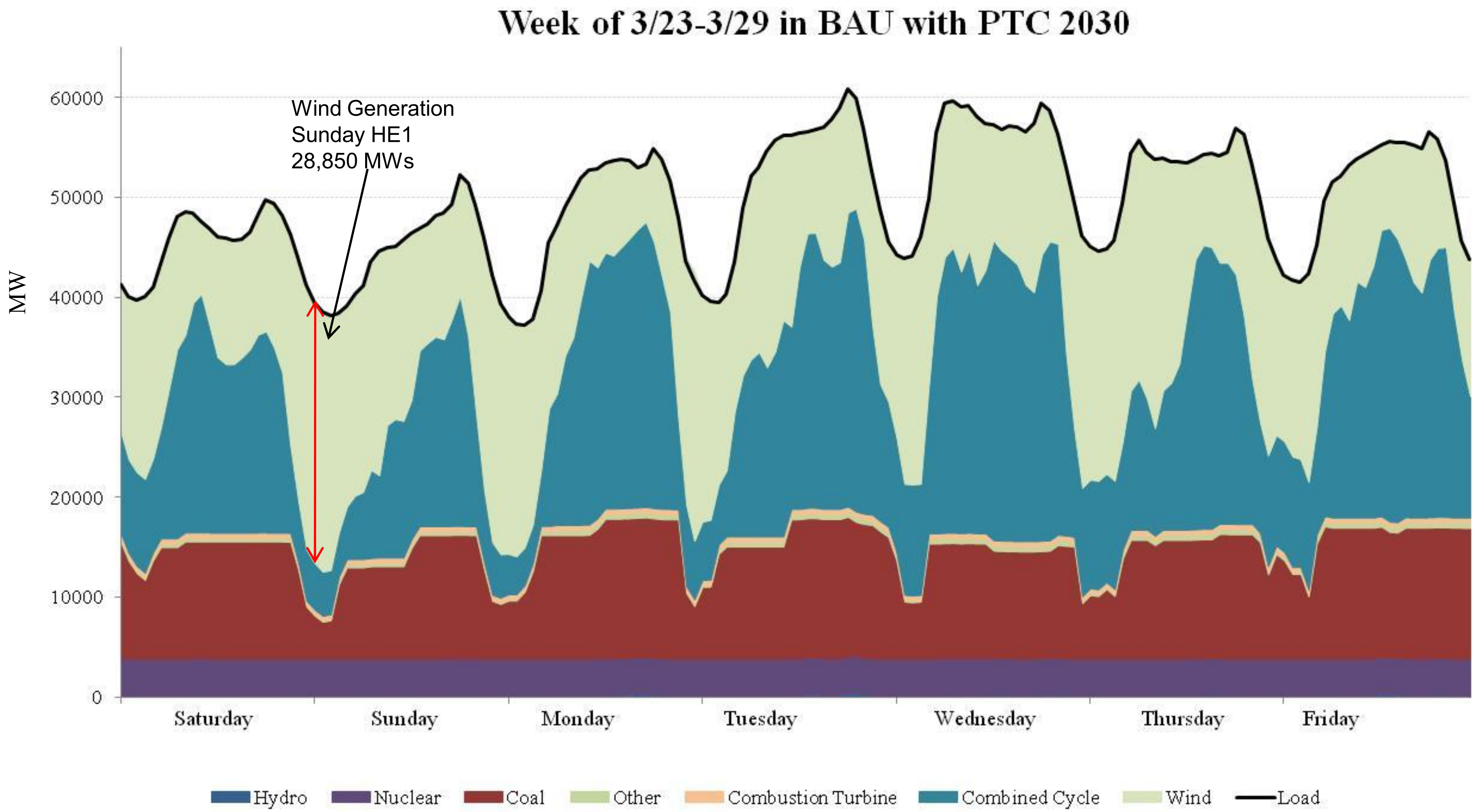
2030 capacity by fuel type:

- 51% Natural gas
- 16% Coal
- 4% Nuclear
- 28% Wind
- 1% Other – Hydro, Biomass, and LFG

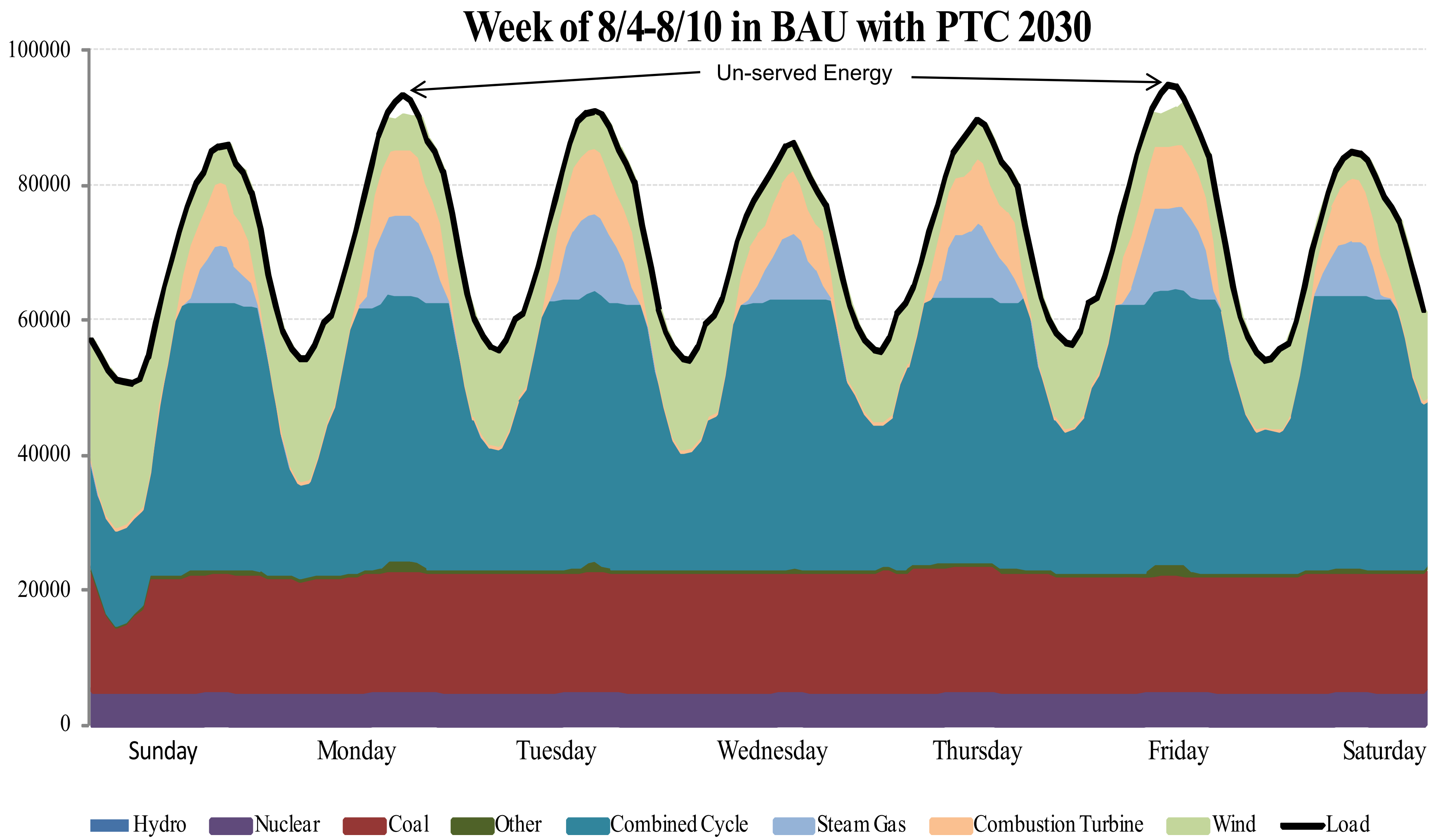


Weekly Generation Pattern

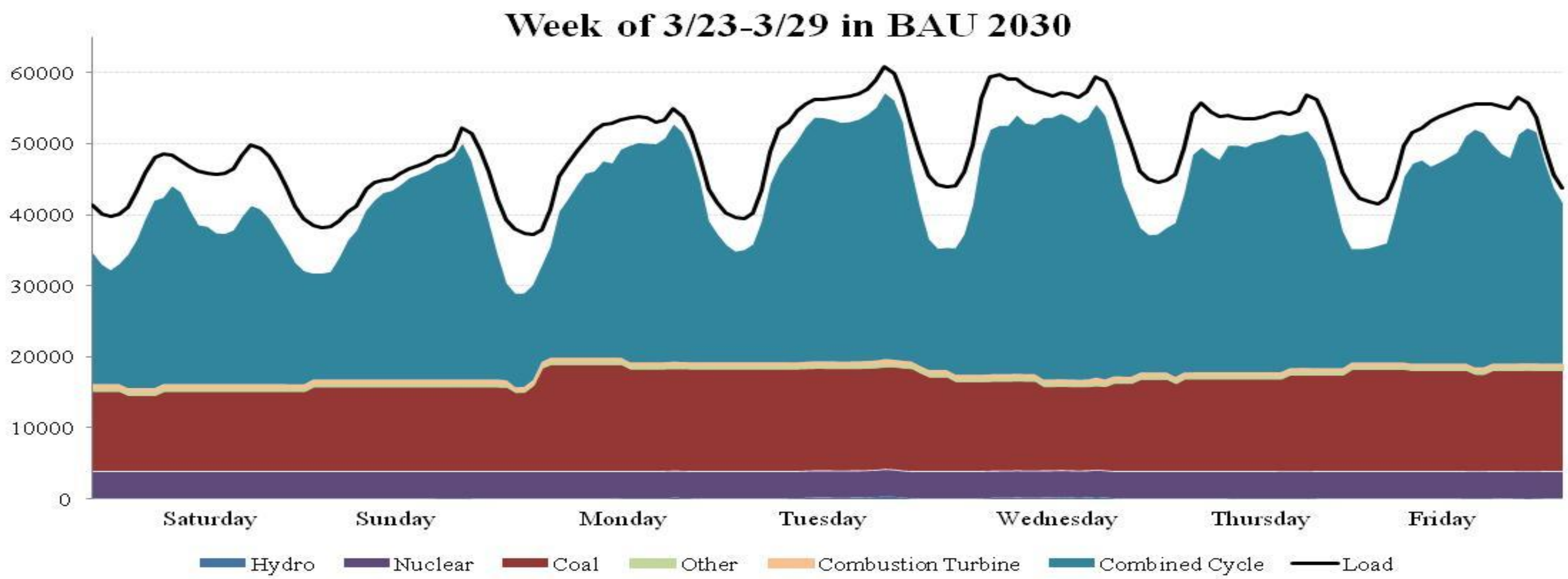
Will require further A/S analysis

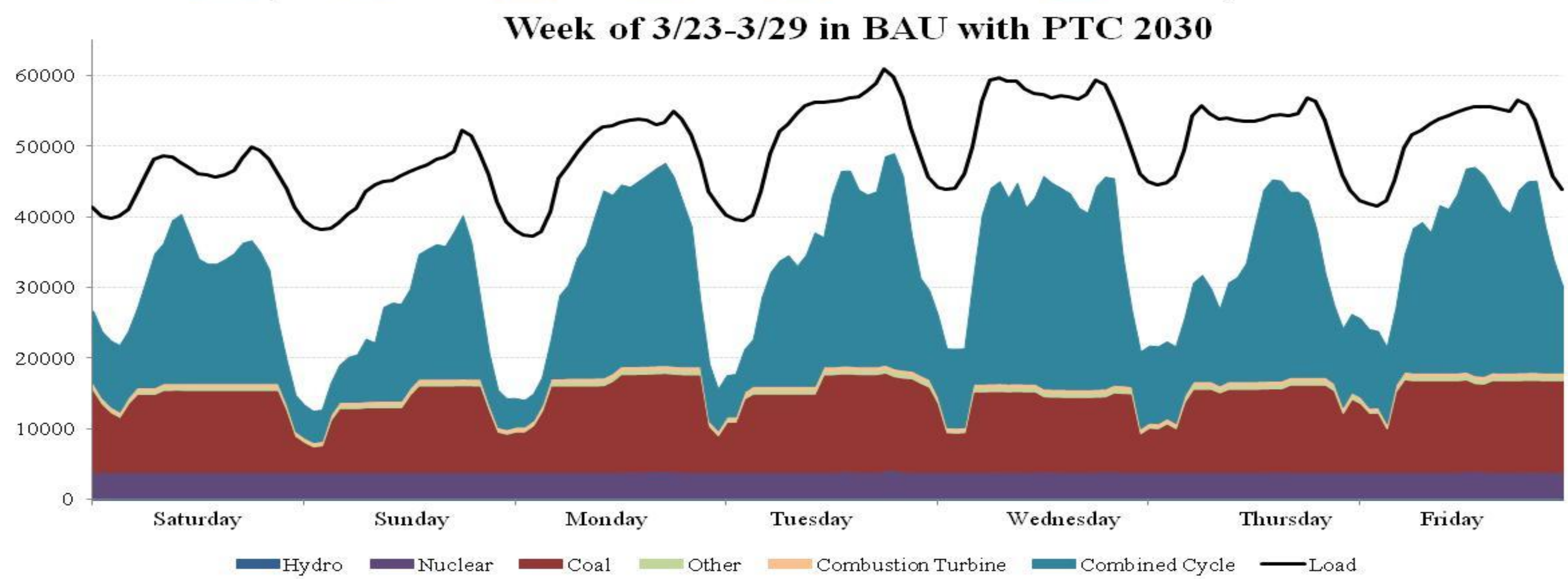


Weekly Generation Pattern



BAU 2030 With and Without PTC Comparisons


Week of 3/23-3/29 in BAU 2030
60000
50000
40000
30000
20000
10000
0
Saturday
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Hydro
Nuclear
Coal
Other
Combustion Turbine
Combined Cycle
Load


Week of 3/23-3/29 in BAU with PTC 2030
60000
50000
40000
30000
20000
10000
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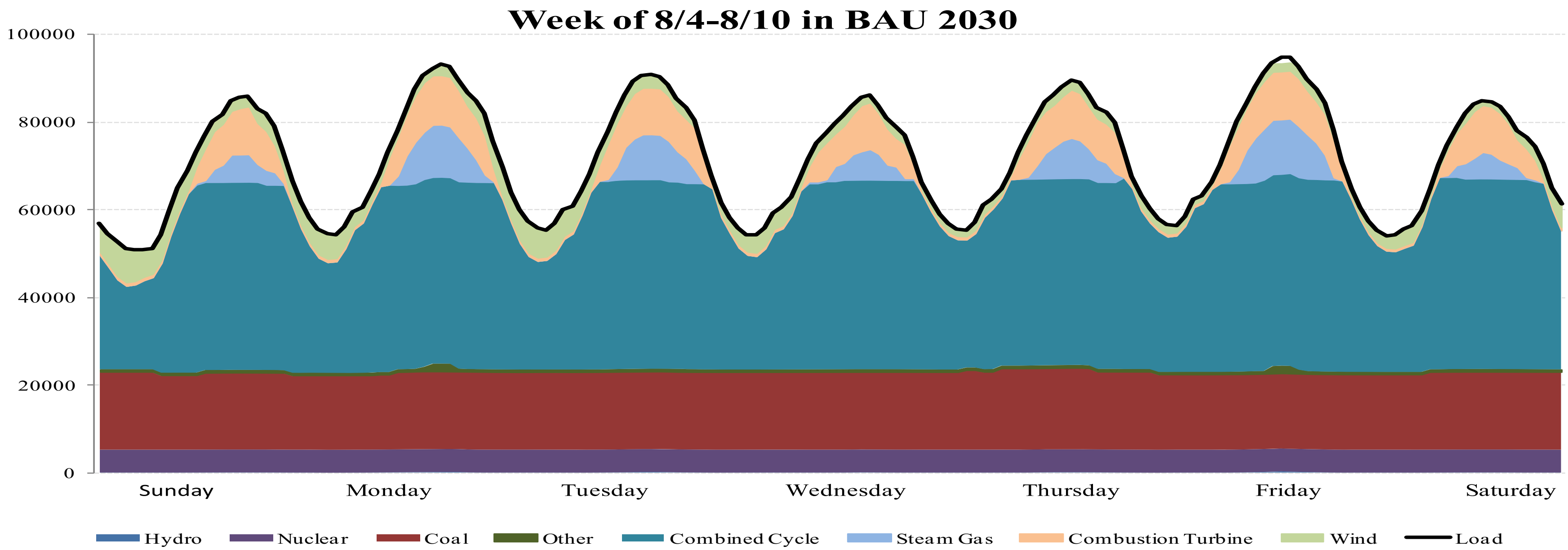
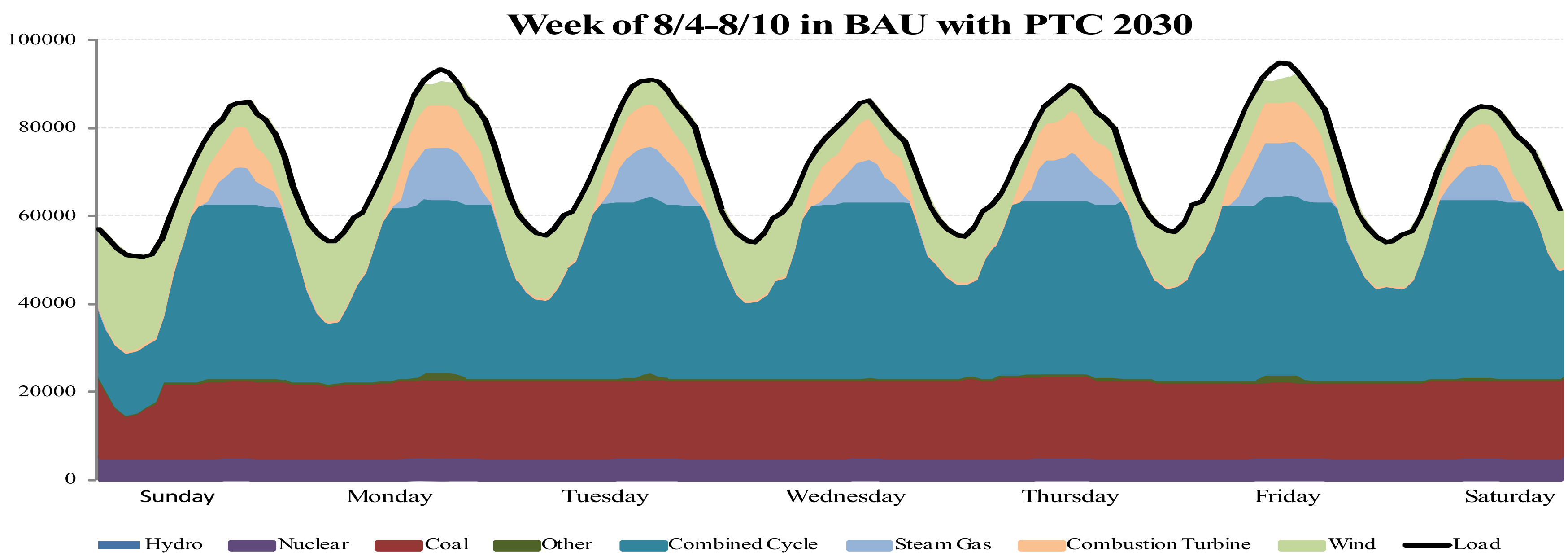
Saturday
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Hydro
Nuclear
Coal
Other
Combustion Turbine
Combined Cycle
Load


Week of 8/4-8/10 in BAU 2030
100000
80000
60000
40000
20000
0
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday
Hydro
Nuclear
Coal
Other
Combined Cycle
Steam Gas
Combustion Turbine
Wind
Load


Week of 8/4-8/10 in BAU with PTC 2030
100000
80000
60000
40000
20000
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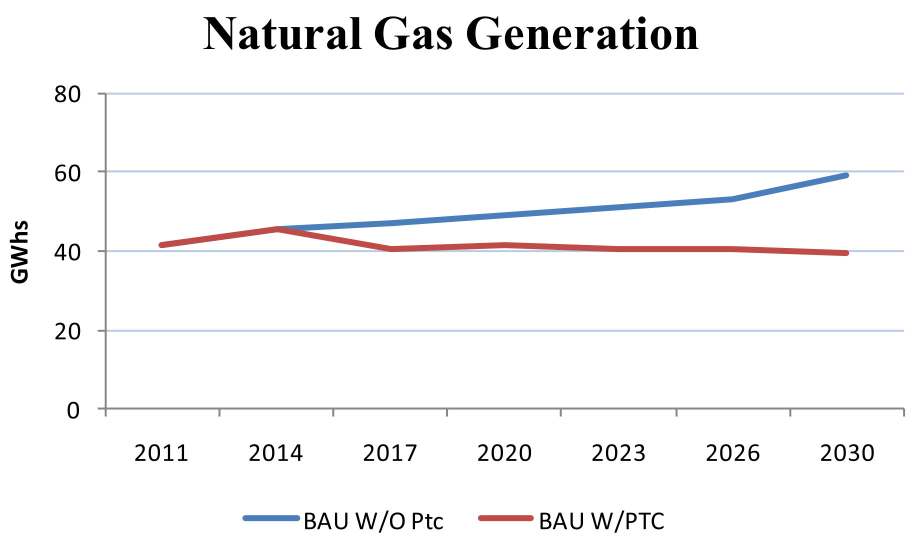
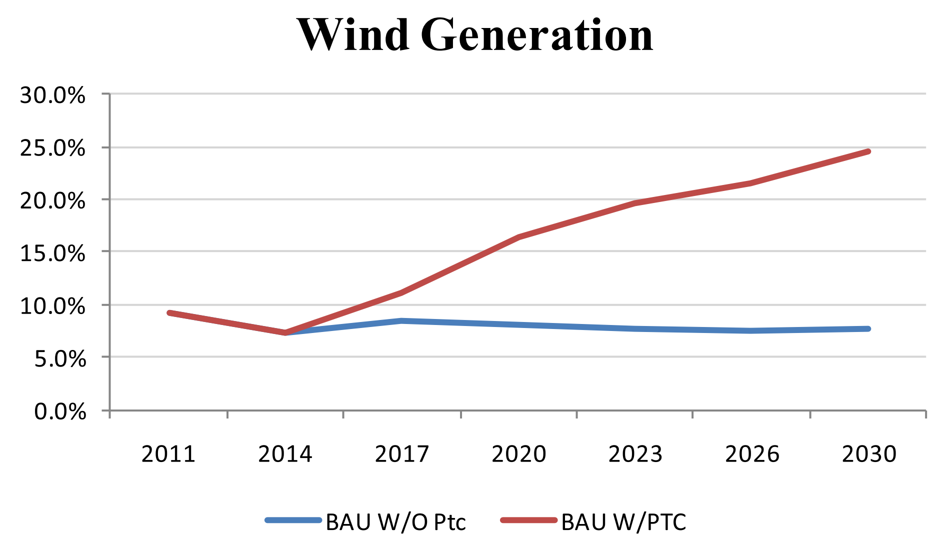
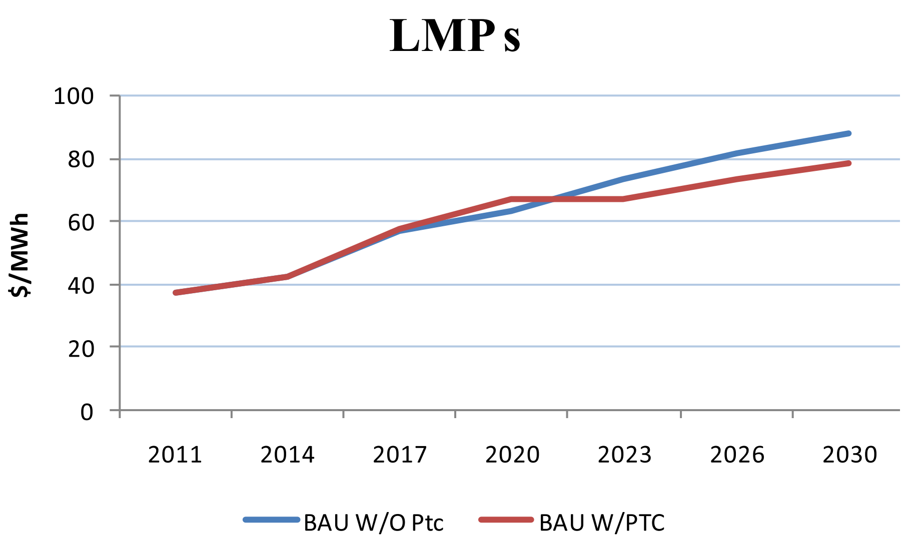
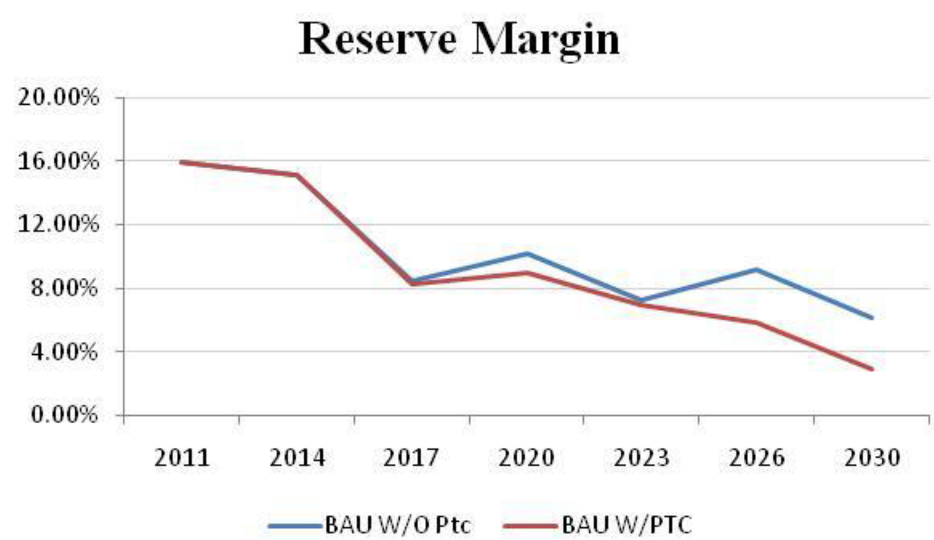
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday
Hydro
Nuclear
Coal
Other
Combined Cycle
Steam Gas
Combustion Turbine
Wind
Load

BAU With and Without PTC Comparisons



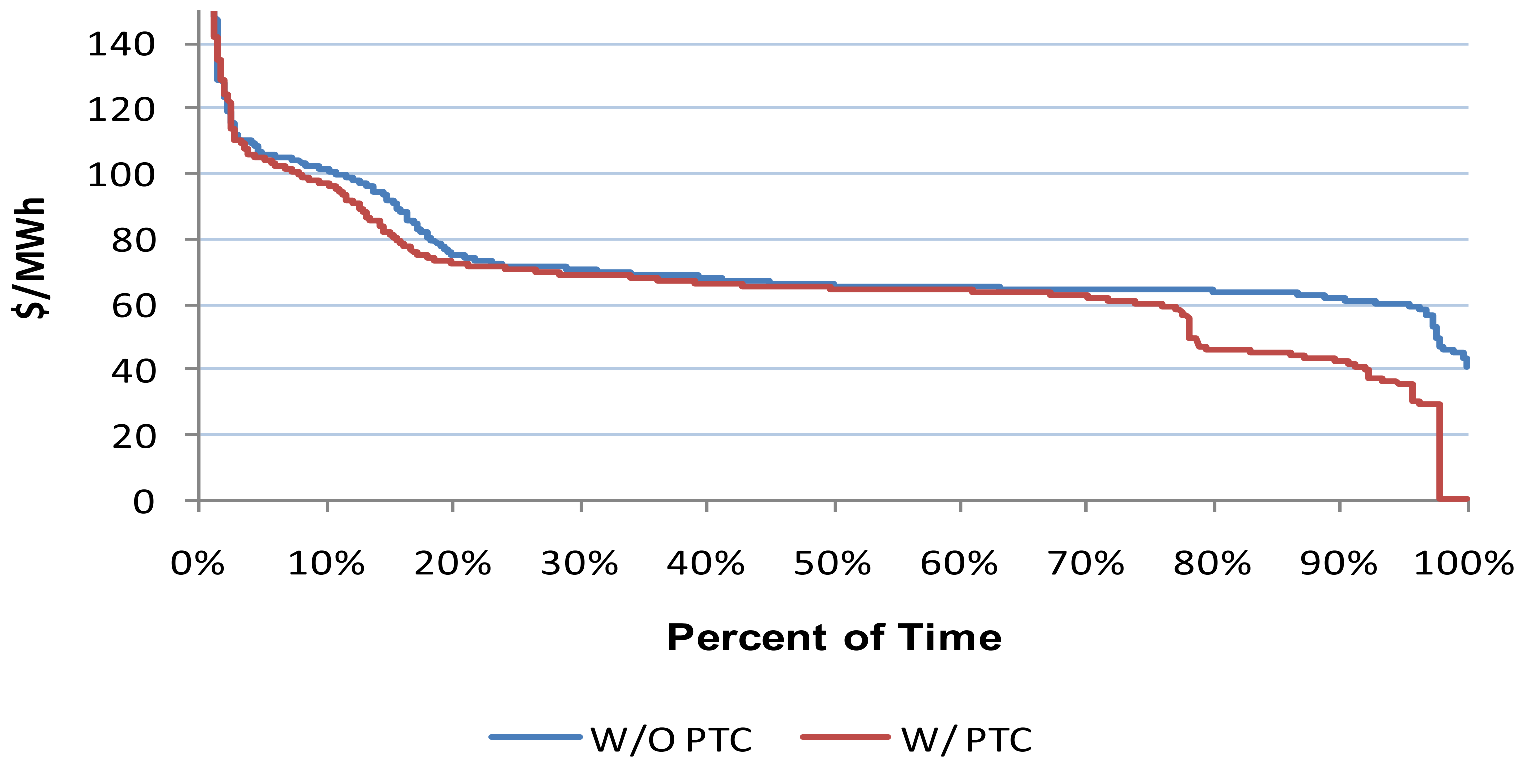






BAU With and Without PTC Comparisons For 2030

Price duration curve shows significant impact during the off peak hours of wind generation



BAU With High Natural Gas Price Sensitivity

BAU High Natural Gas (EIA plus $5/mmbtu) Expansion Plan Results

Total economic wind expansion MWs by 2030:

- 6,000 MWs; total wind on entire system – 16,350 MWs

Total economic thermal expansion builds in 2030:

- 29 coal plants – 17,400 MWs
- Total thermal additions – 17,400 MWs

Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	-	-	-	-	-
CT Adds	MW			-	-	-	-	-	-
Coal Adds	MW			925	3,000	3,000	3,600	3,000	4,800
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			6,872	-	-	-	-	-
Annual Capacity Additions	MW			7,797	3,000	3,000	3,600	3,000	4,800
Cumulative Capacity Additions	MW			7,797	10,797	13,797	17,397	20,397	25,197
Reserve Margin	%	21.4	16.4	12.0	9.7	7.8	8.3	7.0	7.6
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	77.12	84.54	91.90	98.00	107.28	114.68
Natural Gas Price	$/mmbtu	4.38	4.50	9.63	10.10	10.68	11.47	12.35	13.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	8.01	8.37	8.61	8.54	8.69	8.57
Natural Gas Generation	%	38.2	41.3	39.7	36.8	34.7	31.8	29.8	26.3
Coal Generation	%	39.5	37.8	35.5	38.3	41.6	45.3	48.2	52.5
Wind Generation	%	7.8	9.2	12.5	13.2	12.6	12.2	11.7	11.2
Scarcity Hours	HRS	-	-	1	12	22	26	39	46
Unserved Energy	GWhs	-	-	0	7.6	29.0	36.9	44.5	92.5

BAU High Natural Gas with PTC Expansion Plan Results

Total economic wind expansion MWs by 2030:

- 25,000 MWs; total wind on entire system – 35,350 MWs

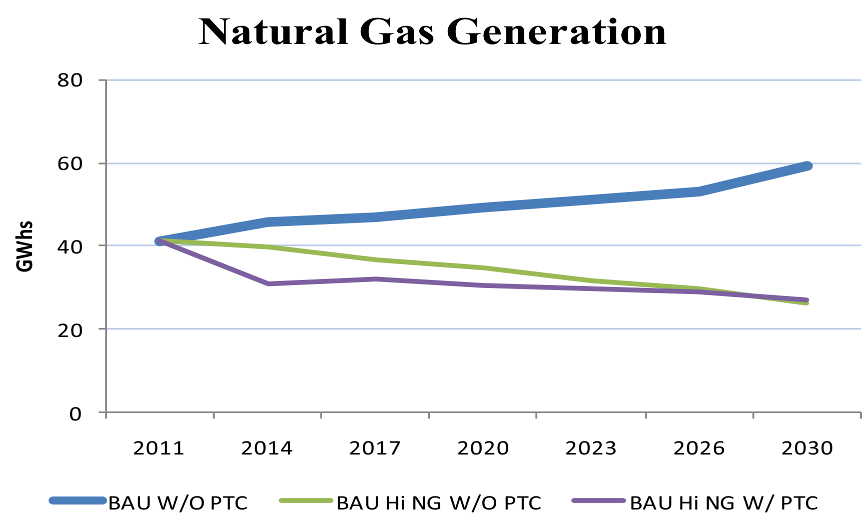
Total economic thermal expansion builds in 2030:

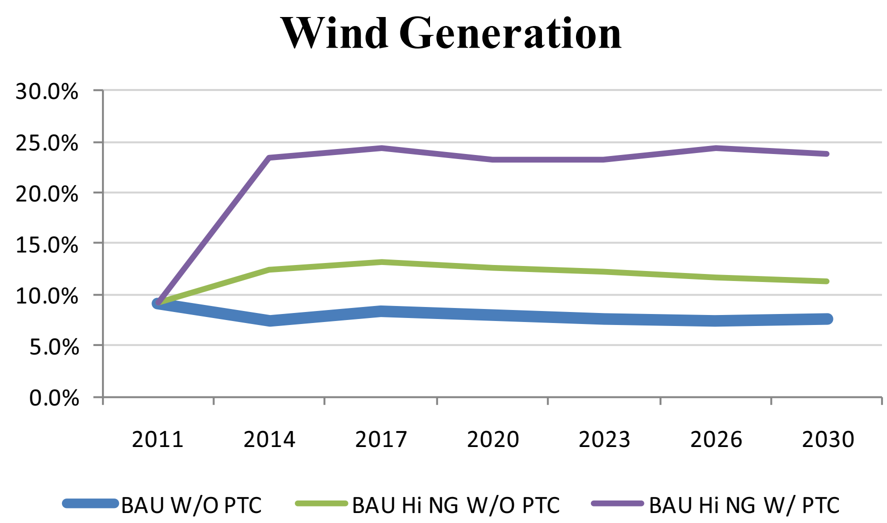
- 17 coal plants – 10,200 MWs
- 46 combustion turbines – 4,600 MWs
- Total thermal additions – 14,800 MWs

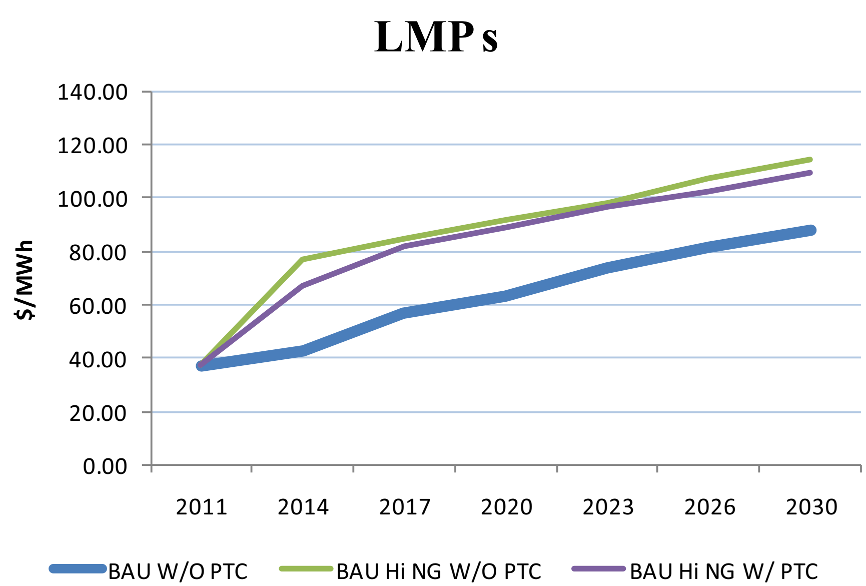
Question: Should we limit the potential annual build-out of specific types of resources?

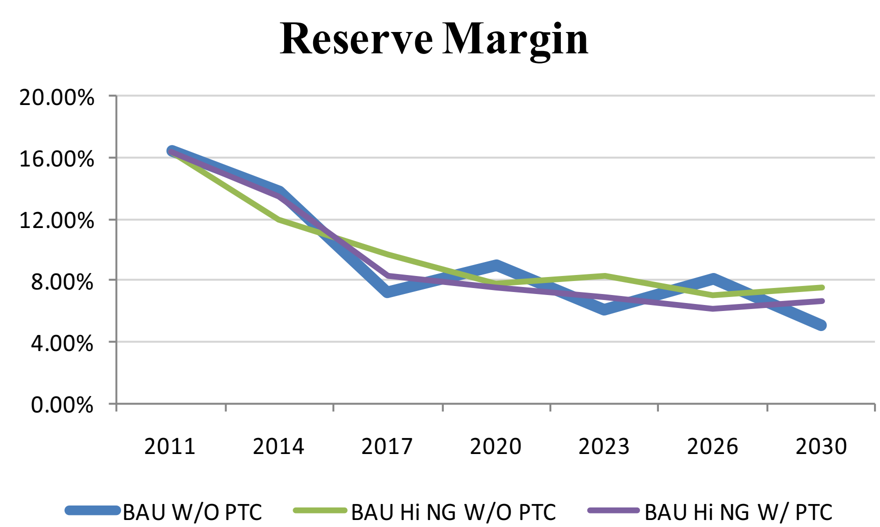
Description	Units	2010 Actual	2011	2014	2017	2020	2023	2026	2030
CC Adds	MW			-	-	-	-	-	-
CT Adds	MW			-	-	1,000	600	2,000	1,000
Coal Adds	MW			925	600	3,000	1,800	1,200	3,600
Nuclear Adds	MW			-	-	-	-	-	-
Other Adds	MW			-	-	-	-	-	-
Wind Adds	MW			19,872	1,000	-	1,000	3,000	1,000
Annual Capacity Additions	MW			20,797	1,600	4,000	3,400	6,200	5,600
Cumulative Capacity Additions	MW			20,797	22,397	26,397	29,797	35,997	41,597
Reserve Margin	%	21.4	16.4	13.5	8.3	7.6	6.9	6.1	6.6
Coincident Peak	MW	65,776	65,206	73,375	78,869	81,665	85,928	88,318	94,318
Average LMP	$/MWh	34.41	37.42	66.98	81.71	88.98	96.85	102.21	109.16
Natural Gas Price	$/mmbtu	4.38	4.50	9.63	10.10	10.68	11.47	12.35	13.39
Average Market Heat Rate	MMbtu/MWh	7.86	8.32	6.96	8.09	8.34	8.44	8.28	8.16
Natural Gas Generation	%	38.2	41.3	30.7	32.1	30.4	29.7	28.9	26.9
Coal Generation	%	39.5	37.8	33.5	32.1	35.4	36.5	36.5	39.3
Wind Generation	%	7.8	9.2	23.5	24.3	23.2	23.2	24.4	23.9
Scarcity Hours	HRS	-	-	1	30	45	52	55	59
Unserved Energy	GWhs	-	-	0	35.7	77.4	90.2	117.1	129.6

BAU to BAU High Natural Gas Comparisons









Questions?

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL
	)	52-013-COL
NUCLEAR INNOVATION NORTH AMERICA LLC	)	
	)	
(South Texas Project Units 3 and 4)	)	July 12, 2011
	)	

NUCLEAR INNOVATION NORTH AMERICA LLC'S PROPOSED QUESTIONS FOR THE BOARD ON NRC STAFF'S DIRECT TESTIMONY OF RICHARD L. EMCH, JR., JEREMY P. RISHEL, AND DAVID M. ANDERSON RELATED TO CONTENTION CL-2

Pursuant to 10 C.F.R. § 2.1207(a)(3), the U.S. Nuclear Regulatory Commission ("NRC") Atomic Safety and Licensing Board's ("Board's") Scheduling Order dated March 11, 2011, and the Board's Initial Scheduling Order dated October 20, 2009, Applicant Nuclear Innovation North America LLC ("NINA") hereby submits its proposed questions for the Board to consider propounding to Mr. Richard L. Emch, Jr., Mr. Jeremy P. Rishel, and Mr. David M. Anderson at the evidentiary hearing regarding Contention CL-2. These questions are based on Mr. Emch's, Mr. Rishel's, and Mr. Anderson's direct testimony filed on May 9, 2011, related to Contention CL-2.

Following the Board's guidelines for submittals of proposed questions for the Board to ask direct and rebuttal witnesses, this submittal provides a brief description of the issues that NINA contends need further examination, the objective of the examination, and the proposed line of questioning that may logically lead to achieving the objective.[1]

[1] *See* Initial Scheduling Order, at 16 (Oct. 20, 2009).

I. STP CAPACITY FACTOR

A. Brief Description of the Issue

Is 96% the correct capacity factor for the STP units?

B. References

Exh. NRC000020.

C. Objective of the Examination

Demonstrate that 96% is not the correct capacity factor for the STP units.

D. Proposed Line of Questioning

- Mr. Emch, Mr. Rishel, and Mr. Anderson, Exhibit NRC000020 says that STP had a capacity factor of approximately 96%. Do you agree that is the summer capacity factor and not an annual capacity?
- Would you agree that the summer capacity factor is likely to be higher than the annual capacity factor, because refueling outages are typically scheduled for the spring and fall?

II. MOTION FOR SUMMARY DISPOSITION CALCULATIONS

A. Brief Description of the Issue

Did the Applicant use Exhibits NRC000024, NRC000025, and NRC000030 to support its prefiled testimony?

B. References

Exhs. NRC000024, NRC000025, and NRC000030.

C. Objective of the Examination

Demonstrate that the Applicant did not use Exhibits NRC000024, NRC000025, and NRC000030 to support its prefiled testimony.

D. Proposed Line of Questioning

- Mr. Emch, Mr. Rishel, and Mr. Anderson, do you agree that Exhibits NRC000024, NRC000025, and NRC000030 were prepared by the Applicant to support its motion for summary disposition?
- Do you agree that these exhibits were not necessarily used by the Applicant to support its prefiled testimony?

III. 2008 ELECTRIC RELIABILITY COUNCIL OF TEXAS ("ERCOT") HOUSTON ZONE PRICES

A. Brief Description of the Issue

Were the 2008 ERCOT Houston Zone prices anomalously high?

B. References

Emch/Rishel/Anderson Direct Testimony (Exh. NRC000004) at 51-53.

C. Objective of the Examination

Demonstrate that the 2008 ERCOT Houston Zone prices were anomalously high.

D. Proposed Line of Questioning

- Mr. Emch, Mr. Rishel, and Mr. Anderson, on pages 51 to 53 of your direct testimony, you use 2008 ERCOT prices to calculate the market effects of an STP outage.
  - Do you agree that the 2008 prices were anomalously high?
  - Do you also agree that use of such prices results in anomalously high market effects?
- Mr. Emch, Mr. Rishel, and Mr. Anderson, on pages 51 to 53 of your direct testimony, you use the 2008 Houston Zone prices rather than the 2008 ERCOT prices to calculate the market effects of an STP outage.
  - Was your calculation of the market effects for the entire ERCOT region?

- Do you agree that the Houston Zone prices were higher than the ERCOT prices?
- Do you also agree that use of the Houston Zone prices results in higher market effects?

Respectfully submitted,

Signed (electronically) by Steven P. Frantz
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Counsel for Nuclear Innovation North America LLC

Dated in Washington, D.C.
this 12th day of July 2011

  - Does the definition of Equipment and Software provided by the Bureau of Economic Analysis exclude components that are installed as part of a nuclear power plant?
    - In particular, I refer you to Exhibit NRC000022, page 6-3, the second row on equipment and software, and the second column which provides a definition of Equipment and Software. Does the last entry for that box explicitly state that Equipment and Software does not include "equipment that are integral parts of structures"?
    - Furthermore, if you look on that same page at the first row, do you agree that equipment that is an integral part of a structure is considered to be part of the Structure part of the index, not the Equipment and Software part?
- On page 6 of your rebuttal testimony, lines 9-11, you state that the non-residential structure component of the GDP implicit price deflator represents "an extreme outlier from other general inflation measures."
  - Is that statement made in the context of the rate of inflation of the overall economy?
  - Does your statement apply to the rate of inflation for non-residential structures?
  - Do you agree that the non-residential structure component of the GDP implicit price deflator is appropriate to use for costs of construction of non-residential buildings?

VI. PRICE SPIKES AND MARKET POWER

A. <u>Brief Description of the Issue</u>

Do price spikes account for increases in prices due to scarcity of supply?

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
NUCLEAR INNOVATION NORTH AMERICA LLC	)	Docket Nos. 52-012-COL and 52-013-COL
(NINA)	)	
	)	
(South Texas Project Units 3 and 4)	)	
	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing **MEMORANDUM AND ORDER (Providing Proposed Questions for Evidentiary Hearing on Contention CL-2)** have been served upon the following persons by the Electronic Information Exchange.

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[Original signed by Nancy Greathead]
Office of the Secretary of the Commission

Dated at Rockville, Maryland
this 3rd day of January 2012