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
STP NUCLEAR OPERATING COMPANY	)	
	)	
(South Texas Project Units 3 and 4)	)	September 14, 2010

STP NUCLEAR OPERATING COMPANY'S MOTION FOR SUMMARY DISPOSITION OF CONTENTION CL-2

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I. INTRODUCTION

In accordance with 10 C.F.R. § 2.1205 and the October 20, 2009 Initial Scheduling Order, STP Nuclear Operating Company ("STPNOC"), applicant in the above-captioned proceeding, hereby submits this motion for summary disposition requesting that the Atomic Safety and Licensing Board ("Board") dismiss Contention CL-2 regarding STPNOC's estimation of replacement power costs in the evaluation of severe accident mitigation design alternatives ("SAMDAs") in Section 7.5S of the Environmental Report ("ER") for STP Units 3 and 4.

This motion is supported by the accompanying "Joint Affidavit of Jeffrey L. Zimmerly and Adrian Pieniazek" ("Joint Affidavit") and the "Statement of Material Facts on Which No Genuine Issue Exists in Support of STP Nuclear Operating Company's Motion for Summary Disposition of Contention CL-2" ("Statement of Material Facts"). Mr. Zimmerly is an Environmental Engineer with Tetra Tech NUS, Inc., a contractor to STPNOC for STP Units 3 and 4, and Mr. Pieniazek is the Director of Market Policy for NRG Texas LLC.

As discussed below, Contention CL-2 should be dismissed because there is no genuine issue as to any material fact on this contention, and STPNOC, as the moving party, is entitled to a decision as a matter of law.

II. PROCEDURAL BACKGROUND

On September 20, 2007, STPNOC submitted an application to the Nuclear Regulatory Commission ("NRC") for combined licenses ("COLs") for STP Units 3 and 4.[1] The Sustainable Energy and Economic Development Coalition, Susan Dancer, the South Texas Association for Responsible Energy, Daniel A. Hickl, Public Citizen, and Bill Wagner ("Intervenors") filed a "Petition for Intervention and Request for Hearing" ("Petition") on April 21, 2009, alleging 28 separate contentions. The Petition included Contention 21, which claimed that the ER for STP Units 3 and 4 failed to consider the impacts from severe radiological accident scenarios on the operation of other units at the STP site.[2] The Board admitted Contention 21 on August 27, 2009.[3]

On November 11, 2009, STPNOC submitted a notification to the Board regarding Contention 21.[4] That notification informed the Board that STPNOC had submitted a letter to the NRC identifying revisions to the ER ("ER revisions") for STP Units 3 and 4 on November 10, 2009.[5] Specifically, STPNOC had created a new ER Section 7.5S that evaluates the impacts that a design basis accident or severe accident at one of the new or existing units at the STP site

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1 South Texas Project Nuclear Operating Company; Notice of Receipt and Availability of Application for a Combined License, 72 Fed. Reg. 60,394 (Oct. 24, 2007).

2 Petition at 46.

3 *South Texas Project Nuclear Operating Co.* (South Texas Project Units 3 and 4), LBP-09-21, 70 NRC __, slip op. at 36-39 (Aug. 27, 2009).

4 Letter from S. Burdick, Counsel for STPNOC, to the Board, Notification of Filing Related to Contention 21 (Nov. 11, 2009) ("Notification Letter").

5 Attachment to Notification Letter, Letter from S. Head, STPNOC, to NRC, Proposed Revision to Environmental Report (Nov. 10, 2009) ("ER Letter").

would have on the other units at the site.[6] ER Section 7.5S.5 provided an evaluation of SAMDAs, assuming that a severe accident in one unit would result in extended shutdowns of the three co-located units at the STP site.

On November 30, 2009, STPNOC requested that the Board dismiss Contention 21 as moot based on the new ER Section 7.5S.[7] On December 22, 2009, the Intervenors sought admission of four new contentions, Contentions CL-1 through CL-4, related to ER Section 7.5S.[8] STPNOC opposed the new and revised contentions and requested that the Board reject them.[9] The NRC staff agreed with STPNOC that the four new contentions and proposed revisions to Contention 21 should be rejected.[10] On January 29, 2010, the Intervenors filed their response.[11]

The Board issued Order LBP-10-14 on July 2, 2010.[12] Among other things, LBP-10-14 dismissed Contention 21, denied the Intervenors' request to amend Contention 21, denied the Intervenors' request to admit Contention CL-1, and admitted Contention CL-2, which is a reformulation of Contentions CL-2, CL-3, and CL-4.[13]

As admitted by the Board, Contention CL-2 states:

> The Applicant's calculation in ER Section 7.5S of replacement power costs in the event of a forced shutdown of multiple STP Units is erroneous because it underestimates replacement power

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6 ER Letter, Attachment, at 1-9.

7 Applicant's Motion to Dismiss Contention 21 as Moot, at 1, 5 (Nov. 30, 2009).

8 Intervenors' Contentions Regarding Applicant's Proposed Revision to Environmental Report Section 7.5S and Request for Hearing (Dec. 22, 2009) ("Intervenors' Request").

9 Applicant's Answer Opposing New and Revised Contentions Regarding Environmental Report Section 7.5S (Jan. 22, 2010).

10 NRC Staff's Answer to the Intervenors' Amended and New Accident Contentions, at 1 (Jan. 22, 2010).

11 Intervenors' Consolidated Response to NRC Staff's Answer to the Intervenors' New Accident Contentions and Applicant's Answer Opposing New Contentions Regarding Applicant's Environmental Report Section 7.5S (Jan. 29, 2010) ("Intervenors' Response").

12 *South Texas Project Nuclear Operating Co.* (South Texas Project Units 3 and 4), LBP-10-14, 72 NRC __, slip op. at 1 (July 2, 2010).

13 *Id.* at 57.

> costs and fails to consider disruptive impacts, including ERCOT market price spikes.[14]

This Motion for Summary Disposition requests dismissal of this Contention CL-2 as admitted by the Board, because the material facts demonstrate that SAMDAs are not cost-effective even after accounting for the factors identified by the Intervenors.

On July 22, 2010, the NRC staff submitted its own Motion for Summary Disposition of Contention CL-2 on the legal grounds that the SAMDA analysis for the Advanced Boiling Water Reactor ("ABWR") to be used at STP Units 3 and 4 has finality, and therefore issues related to SAMDAs are not open to litigation in this proceeding.[15] STPNOC supports that motion.[16] The staff's motion currently is pending before the Board.[17] The staff's motion provides a separate and independent basis for dismissing Contention CL-2.

III. STATEMENT OF THE LAW

A. Law Governing Summary Disposition

In LBP-09-21, the Board ordered that this proceeding be governed by Subparts C and L in 10 C.F.R. Part 2.[18] As stated in 10 C.F.R. § 2.1205 of Subpart L, any party may submit a motion for summary disposition.[19] The motion must be in writing and must include an explanation of the basis of the motion and affidavits to support statements of fact.[20]

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[14] *Id.* at 30.

[15] NRC Staff Motion for Summary Disposition (July 22, 2010).

[16] STP Nuclear Operating Company's Answer Supporting the NRC Staff Motion for Summary Disposition of Contention CL-2 (July 29, 2010).

[17] STPNOC also submitted a Motion for Reconsideration of the decision in LBP-10-14 to admit Contention CL-2. That motion was denied by the Board in a Memorandum and Order issued on August 10, 2010.

[18] *South Texas Project*, LBP-09-21, slip op. at 60.

[19] 10 C.F.R. § 2.1205(a).

[20] *Id.*

In ruling on a motion for summary disposition, a licensing board is directed to apply the standards for summary disposition set forth in 10 C.F.R. § 2.710(d)(2).[21] Pursuant to that section, summary disposition is warranted

> if the filings in the proceeding, depositions, answers to interrogatories, and admissions on file, together with the statements of the parties and the affidavits, if any, show that there is no genuine issue as to any material fact and that the moving party is entitled to a decision as a matter of law.[22]

The NRC's hearing rules "long have allowed summary disposition in cases where there is no genuine issue as to any material fact and where the moving party is entitled to a decision as a matter of law."[23]

The Commission has held that motions for summary disposition are analogous to summary judgment motions under Rule 56 of the Federal Rules of Civil Procedure, and should be evaluated under the same standards.[24] Summary disposition is not simply a "procedural shortcut"; rather, it is designed "to secure the just, speedy and inexpensive determination of every action," and should be granted when appropriate.[25]

The Commission has stated that the level of factual support necessary to withstand summary disposition is expected to be of a much "higher level than at the contention filing

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21 *See id.* § 2.1205(c).

22 *Id.* § 2.710(d)(2). Section 2.710 generally retains the provisions in former Section 2.749 prior to the revision of Part 2 in January 2004. Final Rule, Changes to the Adjudicatory Process, 69 Fed. Reg. 2182, 2227 (Jan. 14, 2004). Therefore, precedents under the former Section 2.749 are applicable to motions for summary disposition under the current provisions in 10 C.F.R. §§ 2.710 and 2.1205.

23 *Carolina Power & Light Co.* (Shearon Harris Nuclear Power Plant), CLI-01-11, 53 NRC 370, 384 (2001) (internal quotations omitted).

24 *Entergy Nuclear Generation Co.* (Pilgrim Nuclear Power Station), CLI-10-11, 71 NRC __, slip op. at 11-12 (Mar. 26, 2010); *Advanced Med. Sys. Inc.* (One Factory Row, Geneva, Ohio 44041), CLI-93-22, 38 NRC 98, 102 (1993)).

25 *Celotex Corp. v. Catrett*, 477 U.S. 317, 327 (1986); *see also Tenn. Valley Auth.* (Hartsville Nuclear Plant, Units 1A, 2A, 1B, 2B), ALAB-554, 10 NRC 15, 20 n.17 (1979).

stage."[26] The reason being, with discovery nearly complete the quality of evidentiary support is expected to be higher.[27]

Pursuant to Supreme Court and NRC case law, the party seeking summary disposition must show the absence of a genuine issue as to any material fact.[28] In response, the party opposing the motion "must set forth *specific facts* showing that there is a genuine issue of fact."[29] In this regard, "[o]nly disputes over facts *that might affect the outcome of the suit under the governing law* will properly preclude the entry of summary judgment. Factual disputes that are irrelevant or unnecessary will not be counted."[30]

To be considered a genuine issue of material fact, "the factual record, *considered in its entirety*, must be enough in doubt so that there is a reason to hold a hearing to resolve the issue."[31] Bare allegations or general denials are insufficient to oppose a motion for summary disposition,[32] as are mere "quotations from or citations to [the] published work of researchers [or experts] who have apparently reached conclusions at variances with the movant's affiants."[33]

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26 Final Rule, Rules of Practice for Domestic Licensing Proceedings—Procedural Changes in the Hearing Process, 54 Fed. Reg. 33,168, 33,171 (Aug. 11, 1989).

27 *Id.*

28 *Adickes v. S.H. Kress & Co*., 398 U.S. 144, 157 (1970); *Advanced Med.*, CLI-93-22, 38 NRC at 102.

29 10 C.F.R. § 2.710(b) (emphasis added).

30 *Anderson v. Liberty Lobby, Inc*., 477 U.S. 242, 248 (1986) (emphasis added).

31 *Cleveland Elec. Illuminating Co.* (Perry Nuclear Power Plant, Units 1 & 2), LBP-83-46, 18 NRC 218, 223 (1983) (emphasis added); *see also Lujan v. Nat'l Wildlife Fed'n*, 497 U.S. 871 (1990) (granting summary judgment because the plaintiff did not set forth facts specific enough to support its claim).

32 *See* 10 C.F.R. § 2.710(b) (stating that "a party opposing the motion may not rest upon the mere allegations or denials of his answer"); *Advanced Med.*, CLI-93-22, 38 NRC at 102; *Houston Lighting & Power Co.* (Allens Creek Nuclear Generating Station, Unit 1), ALAB-629, 13 NRC 75, 78 (1981).

33 *Carolina Power & Light Co.* (Shearon Harris Nuclear Plant, Units 1 & 2), LBP-84-7, 19 NRC 432, 435-36 (1984); *see also United States v. Various Slot Machines on Guam*, 658 F.2d 697, 700 (9th Cir. 1981) (holding that "in the context of a motion for summary judgment, an expert must back up his opinion with specific facts" in an affidavit).

Furthermore, if the party opposing the motion fails to controvert any material fact, then that fact will be deemed admitted.[34]

Submission of expert opinion by an opponent does not preclude summary disposition.[35] First, the affiant must be competent to testify to the matters stated in the affidavit.[36] The licensing board may look at whether the affiant qualifies as an expert by "knowledge, skill, experience, training, or education."[37] Second, the licensing board "must focus on whether the expert opinions are sufficiently grounded upon a factual basis."[38] As such, the party opposing summary disposition cannot defeat the motion by presenting "subjective belief or unsupported speculation,"[39] or improperly supported expert opinion.[40] Thus, in opposing summary disposition, "expert opinion is admissible only if the affiant is competent to give an expert opinion and only if the factual basis for that opinion is adequately stated and explained in the affidavit."[41] Additionally, an intervenor may not add new arguments in an answer to a motion for summary disposition if those arguments could have been raised earlier.[42]

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34 10 C.F.R. § 2.710(a); *Advanced Med.*, CLI-93-22, 38 NRC at 102-03.

35 *See Duke Cogema Stone & Webster* (Savannah River Mixed Oxide Fuel Fabrication Facility), LBP-05-4, 61 NRC 71, 80-81 (2005) ("DCS") ("Conflicting expert opinions . . . do not necessarily preclude summary disposition" as "the nonmoving party cannot avoid summary judgment by presenting an unsupported opinion of an expert."). *See also Raskin v. Wyatt Co.*, 125 F.3d 55, 66 (2d Cir. 1997) (holding that a mere proffer of expert testimony is not a "talisman against summary judgment").

36 10 C.F.R. § 2.710(b).

37 *DCS*, LBP-05-4, 61 NRC at 80 (citing Fed. R. Evid. 702).

38 *Id.* at 81.

39 *Id.* at 80 (quoting *Daubert v. Merrell Dow Pharms., Inc.*, 509 U.S. 579, 589-90 (1993)); *see also Brown v. City of Houston*, 337 F.3d 539, 541 (5th Cir. 2003) ("Unsubstantiated assertions, improbable inferences, and unsupported speculation are not sufficient to defeat a motion for summary judgment.").

40 *DCS*, LBP-05-4, 61 NRC at 81.

41 *Id.*

42 *Pilgrim*, CLI-10-11, slip op. at 29-31.

If the moving party makes a proper showing, and the opposing party does not show that a genuine issue of material fact exists, then the licensing board may summarily dispose of the contentions on the basis of the pleadings.[43]

B. <u>Law Governing Environmental Impacts</u>

Contention CL-2 raises environmental issues under the National Environmental Policy Act ("NEPA"). NEPA requires that federal agencies, such as the NRC, prepare an Environmental Impact Statement ("EIS") for "major Federal actions significantly affecting the quality of the human environment."[44] NEPA does not mandate substantive results; rather, it imposes procedural restraints on agencies, requiring them to take a "hard look" at the environmental impacts of a proposed action and reasonable alternatives to that action.[45]

This "hard look" is subject to the "rule of reason."[46] This means that an "agency's environmental review, rather than addressing every impact that could possibly result, need only account for those that have some likelihood of occurring or are reasonably foreseeable."[47] Consideration of "remote and speculative" or "inconsequentially small" impacts is not required.[48] As the Commission explained, "NEPA also does not call for certainty or precision,

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43 *N. States Power Co.* (Prairie Island Nuclear Generating Plants, Units 1 & 2), CLI-73-12, 6 AEC 241, 242 (1973), *aff'd sub nom. BPI v. AEC*, 502 F.2d 424 (D.C. Cir. 1974) ("It remains for [the intervenor] to establish, to the satisfaction of the Board which has been convened to conduct the hearing, that a genuine issue actually exists. If the Board is not so satisfied, it may summarily dispose of the contention on the basis of the pleadings.").

44 42 U.S.C. § 4332(2)(C) (2006).

45 *See La. Energy Servs., L.P.* (Claiborne Enrichment Ctr.), CLI-98-3, 47 NRC 77, 87-88 (1998); *see also Balt. Gas & Elec. Co. v. Natural Res. Def. Council, Inc.*, 462 U.S. 87, 97-98 (1983) (NEPA requires agency to take a "hard look" at environmental consequences prior to taking major action).

46 *La. Energy Servs., L.P.* (National Enrichment Facility), LBP-06-8, 63 NRC 241, 258 (2006) (citing *Long Island Lighting Co.* (Shoreham Nuclear Power Station), ALAB-156, 6 AEC 831, 836 (1973)); *see also Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 767-69 (2004) (stating that the rule of reason is inherent in NEPA and its implementing regulations).

47 *National Enrichment*, LBP-06-8, 63 NRC at 258-59 (citing *Shoreham*, ALAB-156, 6 AEC at 836).

48 *See Vt. Yankee Nuclear Power Corp.* (Vermont Yankee Nuclear Power Station), ALAB-919, 30 NRC 29, 44 (1989) (citing *Limerick Ecology Action, Inc. v. NRC*, 869 F.2d 719, 739 (3d Cir. 1989)).

but an *estimate* of anticipated (not unduly speculative) impacts."[49] When faced with uncertainty, NEPA only requires "reasonable forecasting."[50] Similarly, the U.S. Supreme Court has held that NEPA does not require a "worst case analysis."[51]

Additionally, economic forecasts under NEPA are legally sufficient if they are reasonable. The Commission recently stated in *Pilgrim*:

> There is no NEPA requirement to use the best scientific methodology, and NEPA "should be construed in the light of reason if it is not to demand" virtually infinite study and resources. Nor is an environmental impact statement intended to be a "research document," reflecting the frontiers of scientific methodology, studies and data. NEPA does not require agencies to use technologies and methodologies that are still "emerging" and under development, or to study phenomena "for which there are not yet standard methods of measurement or analysis." And while there "will always be more data that could be gathered," agencies "must have some discretion to draw the line and move forward with decisionmaking." In short, NEPA allows agencies "to select their own methodology as long as that methodology is reasonable."[52]

The Commission has stated that consideration should be given to "whether the economic assumptions . . . were so distorted as to impair fair consideration of . . . environmental effects."[53] Similarly, in the context of power forecasts, the Appeal Board held in *Nine Mile Point* that "inherent in any forecast . . . is a substantial margin of uncertainty," and therefore the forecast should be accepted if it is "reasonable."[54] Therefore, economic forecasts are subject to

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[49] *La. Energy Servs. L.P.* (National Enrichment Facility), CLI-05-20, 62 NRC 523, 536 (2005).

[50] *Scientists' Inst. for Pub. Info., Inc. v. AEC*, 481 F.2d 1079, 1092 (D.C. Cir. 1973).

[51] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 354-55 (1989).

[52] *Pilgrim*, CLI-10-11, slip op. at 37 (citations omitted).

[53] *Private Fuel Storage, LLC* (Independent Spent Fuel Storage Installation), CLI-04-22, 60 NRC 125, 145 (2004).

[54] *Niagara Mohawk Power Corp.* (Nine Mile Point Nuclear Station, Unit 2), ALAB-264, 1 NRC 347, 365-67 (1975). The Commission has endorsed the Nine Mile Point rule. *See Carolina Power & Light Co.* (Shearon Harris Nuclear Power Plant, Units 1, 2, 3, & 4), CLI-79-5, 9 NRC 607, 609-10 (1979).

substantial uncertainty and, as long as they are reasonable, they are not open to criticism because some other person has an opposing view.[55]

IV. OVERVIEW OF STPNOC'S SAMDA EVALUATION IN ER §§ 7.3 AND 7.5S.5

The ER for STP Units 3 and 4 presents a site-specific analysis of Severe Accident Mitigation Alternatives ("SAMAs"). SAMAs consist of two types of alternatives: 1) SAMDAs; and 2) alternatives involving administrative controls, such as procedures and training.[56]

With respect to SAMAs involving administrative controls, ER Section 7.3.3 states that evaluation of specific administrative controls will occur when the design for STP Units 3 and 4 is finalized and plant administrative processes and procedures are being developed. Under the licensing process established in 10 C.F.R. Part 52, procedures and training do not need to be finalized in order to obtain a COL and instead can be developed during construction.[57] Prior to fuel load, appropriate administrative controls on plant operations will be developed and incorporated into the management systems for STP Units 3 and 4. Therefore, because procedures and training materials have not and do not need to be developed at this time, and because appropriate procedures and training to mitigate accidents will be developed before fuel load, there is no further evaluation of alternative administrative controls that can fruitfully be

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55 *See Nw. Envtl. Advocates v. Nat'l Marine Fisheries Serv.*, 460 F.3d 1125, 1143-44 (9th Cir. 2006) (finding no merit in the petitioner's argument that a multi-port analysis should have been included in the agency's economic analysis, where the assumptions and overall conclusions of the agency's economic analysis were "reasonable"); *S. La. Envtl. Council, Inc. v. Sand*, 629 F.2d 1005, 1014 (5th Cir. 1980) (rejecting plaintiffs' argument that the estimate of fair rental value of equipment moving through a project's waterways should have been calculated differently when the agency's calculation was fair and reasonable).

56 Joint Affidavit ¶ 10.

57 *See, e.g.*, 10 C.F.R. § 52.79(a)(10), (11), (13), (14), (15), (29), (33), (40), which require COL applications to provide a description of various operational and training programs and plans, as distinct from procedures themselves. As the Commission has stated, descriptions of operational programs are provided and reviewed by the Commission as part of the COL application and subsequently the more detailed procedures are implemented by the applicant and inspected by the NRC before plant operation. 74 Fed. Reg. 13,926, 13,933 (Mar. 27, 2009). The Board has previously recognized this principle in this proceeding in the context of 10 C.F.R. § 52.80(d). *See South Texas Project Nuclear Operating Co.* (South Texas Project Units 3 and 4), LBP-10-02, 71 NRC __, slip op. at 24-25 (Jan. 29, 2010).

conducted at this time.[58] The Intervenors have not contested this evaluation in ER Section 7.3.3, which applies equally to SAMA evaluations involving co-located units. As a result, only the evaluation of SAMDAs remains.

To perform a SAMDA evaluation, the cost of each SAMDA is compared against the benefit of implementing the SAMDA.[59] If the benefit from averting all severe accidents is greater than the lowest cost of the SAMDAs, then the SAMDA is considered further.[60]

The costs of SAMDAs for designs certified under 10 C.F.R. Part 52 are determined as part of the design certification process.[61] For the ABWR, the design selected for STP Units 3 and 4, the SAMDA costs were determined in the Technical Support Document ("TSD") submitted as part of the ABWR design certification application.[62] The lowest-cost SAMDA for the ABWR was estimated to be $100,000 (1991 dollars).[63] This lowest-cost corresponds to SAMDAs for improved vacuum breakers, drywell head flooding, and Reactor Building sprays.[64]

The benefits of SAMDAs are determined using a probabilistic-based approach for estimating the maximum averted cost-risk of the severe accidents.[65] This approach accounts for exposure costs, cleanup costs, and replacement power costs associated with the postulated severe accident and corresponding outages, and factors in the likelihood of the severe accident as

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58 Joint Affidavit ¶ 10.

59 *Id.* ¶ 11.

60 *Id.*

61 Statement of Material Facts § II.A.

62 *Id.* § II.B.

63 *Id.* § II.C. The conversion factor from 1991 dollars to both 2008 or 2009 dollars using the consumer price index Bureau of Labor Statistics is 1.58. Joint Affidavit ¶ 30. Thus, in 2008 or 2009 dollars, the lowest-cost SAMDA is $158,000. Statement of Material Facts § II.C.

64 Statement of Material Facts § II.D.

65 Joint Affidavit ¶ 13.

demonstrated by the reactor's Core Damage Frequency ("CDF").[66] In calculating the benefits of SAMDAs (*i.e.*, the maximum averted cost-risk), STPNOC has conservatively assumed that the SAMDA would completely prevent all severe accidents.[67] Additionally, for purposes of STPNOC's SAMDA evaluation, accidents originating at STP Units 1 and 2 were not considered because there are no SAMDAs for STP Units 3 and 4 that could prevent or mitigate an accident at STP Units 1 and 2.[68]

STPNOC's SAMDA evaluation for an ABWR experiencing a severe accident is provided in ER Section 7.3, while the SAMDA evaluation for the co-located units is provided in ER Section 7.5S. The replacement power costs used in these SAMDA evaluations followed NRC's guidance in NUREG/BR-0184, "Regulatory Analysis Technical Evaluation Handbook" (Jan. 1997).[69]

NUREG/BR-0184 states that typical short-term replacement power costs for a 910 MWe power plant are $310,000 per day (1993 dollars).[70] To determine replacement power costs for the co-located units following a severe accident at the STP site, this value was first multiplied by the estimated outage duration of the co-located units to determine the generic replacement power costs.[71] For a hypothetical severe accident at an ABWR unit, STPNOC assumed that the outage

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66 Statement of Material Facts §§ III.F, III.G.

67 Joint Affidavit ¶ 14. This is conservative, because there are no SAMDAs that would prevent all severe accidents. *Id.*; Statement of Material Facts § II.E.

68 Statement of Material Facts § II.F; ER Letter, Attachment, at 7. This is supported by the Board's conclusion that "any allegations involving <u>only</u> STP Units 1 and 2 are outside the scope of this proceeding and cannot be considered by the Board, which is solely concerned with the licensing of proposed STP Units 3 and 4." *South Texas Project*, LBP-10-14, slip op. at 25 n.140.

69 Statement of Material Facts § III.B. NRC guidance documents are entitled to substantial weight. *See, e.g.*, *Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), CLI-01-22, 54 NRC 255, 264 (2001) ("Where the NRC develops a guidance document to assist in compliance with applicable regulations, it is entitled to special weight."). Selections from NUREG/BR-0184 are provided with the Joint Affidavit as STP Attachment 4.

70 Statement of Material Facts § III.C.

71 *Id.* § III.D.

duration at the co-located ABWR is six years and the outage duration at the co-located STP Units 1 and 2 is two years.[72] The Intervenors have not contested these assumptions, which were used in the report prepared by Clarence L. Johnson ("Johnson Report") that was attached to Intervenors' Request.[73] These generic replacement power costs were then used in an equation specified in NUREG/BR-0184 to calculate the net present value of replacement power over the life of the facility, based on a discount rate of 7% (and 3% in a sensitivity analysis).[74] The Intervenors have not contested the 7% discount rate, and the Johnson Report also uses a 7% discount rate.[75] STPNOC then scaled up the net present value from a 910 MWe plant to a 1350 MWe plant for the ABWR and 1280 MWe each for STP Units 1 and 2.[76] Finally, STPNOC used the CDF for an ABWR ($1.56x10^{-7}$ per year) to obtain the replacement power costs for use in the SAMDA evaluation.[77]

The CDF of $1.56x10^{-7}$ per year is for internal events at full power.[78] As the Licensing Board has already ruled in rejecting Contention CL-1 Parts B and C, there is no genuine dispute that the risk of low power and shutdown events is low and the impact from external events is small.[79] Therefore, accounting for the probability of external events and low power and shutdown events would not have a material impact on the total CDF for STP Units 3 and 4.[80]

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72 *Id.*

73 *See* Johnson Report at 4.

74 Statement of Material Facts § III.E.

75 *See* Johnson Report at 4.

76 Statement of Material Facts § III.F.

77 *Id.*

78 *Id.* § I.F.

79 *South Texas Project*, LBP-10-14, slip op. at 20, 22.

80 Statement of Material Facts § I.G.

The replacement power costs calculated using the methodology in NUREG/BR-0184 were added to the other monetized impacts (*e.g.*, onsite exposure cost and onsite cleanup cost) to provide the total monetized impacts for each unit.[81] Using this methodology, STPNOC determined that the lowest-cost SAMDA is much more costly than the total monetized impacts of the accident; therefore, STPNOC concluded that there are no cost-effective SAMDAs.[82]

V. THERE ARE NO GENUINE ISSUES OF MATERIAL FACT RELATED TO THE CONTENTIONS, AND STPNOC IS ENTITLED TO JUDGMENT AS A MATTER OF LAW

A. STPNOC's Replacement Power Cost Estimates Are Reasonable

As discussed above, economic forecasts are subject to substantial uncertainty, and NEPA only requires that they be reasonable.[83] STPNOC's calculation of replacement power costs in ER Section 7.5S was reasonable, and therefore satisfies the requirements of NEPA.

First, STPNOC used NUREG/BR-0184 to calculate replacement power costs, which provides NRC guidance for calculating these costs.[84] NUREG-1555, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants," permits use of NUREG/BR-0184 for SAMDA evaluations.[85] Specifically, NUREG-1555, Section 7.3, states that "[r]egulatory positions and specific criteria necessary to meet the regulations" are provided in "NUREG/BR-0184 (NRC 1997b) with respect to the value impact methodology."[86] Thus, NUREG/BR-0184 provides an accepted NRC methodology for use in SAMDA analyses.[87]

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81 *Id.* § III.G.

82 *Id.* § III.H.

83 *See Pilgrim*, CLI-10-11, slip op. at 37; *Private Fuel Storage*, CLI-04-22, 60 NRC at 145; *Nine Mile*, ALAB-264, 1 NRC at 365-67.

84 Statement of Material Facts § III.B.

85 Joint Affidavit ¶¶ 16, 27; NUREG-1555, at 7.3-3. Selections from NUREG-1555 are provided with the Joint Affidavit as STP Attachment 5.

86 NUREG-1555, at 7.3-3.

87 Joint Affidavit ¶ 16.

Second, NUREG/BR-0184 specifies replacement power costs from a similar time period as the SAMDA analysis for the ABWR.[88] As noted above, the ABWR SAMDA costs from the TSD are provided in 1991 dollars.[89] The replacement power costs in NUREG/BR-0184 that STPNOC relied upon are provided in 1993 dollars.[90] Therefore, these costs are from similar years and can be compared.[91] In contrast, the replacement power costs in the Johnson Report are in 2008 dollars, which should not be directly compared to the ABWR SAMDA costs from 17 years earlier.[92] When the NUREG/BR-0184 replacement power costs are escalated to account for inflation (using a 1.45 producer price index-commodities Bureau of Labor Statistics multiplier), the replacement power cost estimates in 2008 dollars are substantially higher.[93]

In summary, the replacement power costs used by STPNOC in its SAMDA evaluation are reasonable, which is all that is required by NEPA. Although the Intervenors have claimed that the actual ERCOT prices will be higher than the replacement power costs in NUREG/BR-0184, they have not claimed that the replacement power costs in NUREG/BR-0184 are unreasonable. As discussed above, an economic forecast that is reasonable is not subject to attack on the grounds that another party has a different forecast.[94] Therefore, Contention CL-2 should be dismissed.

Nevertheless, as discussed in the following section, even if the methodology suggested by the Intervenors and the Johnson Report is used, there is no genuine issue of material fact that the

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88 *Id.* ¶ 28.

89 Statement of Material Facts § II.C.

90 *Id.* § III.C.

91 Joint Affidavit ¶ 28.

92 *Id.*

93 *Id.*

94 *See, e.g.*, *Pilgrim*, CLI-10-11, slip op. at 37; *see also Nw. Envtl. Advocates*, 460 F.3d at 1143-44; *Sand*, 629 F.2d at 1014.

resulting monetized impacts would still be less than the lowest cost of the SAMDAs; *i.e.*, there would be no cost-effective SAMDAs.

B. The Information Previously Provided by the Intervenors Does Not Establish a Genuine Issue of Material Fact

Nothing provided by the Intervenors to date is inconsistent with the material facts. The Intervenors have provided a series of mandatory discovery disclosures pursuant to 10 C.F.R. § 2.336. All of those disclosures have stated that the Intervenors do not have "any documents that require disclosure."[95] Therefore, the Intervenors have not provided any information during discovery that is inconsistent with the Statement of Material Facts.

The only other relevant information raised by the Intervenors consists of their late-filed contentions on the replacement power cost estimates for the co-located units following a severe accident at the STP site. As demonstrated below, this information is not inconsistent in any material respect with the Statement of Material Facts attached to this motion.

1. Use of ERCOT Cost Data Would Not Affect the Conclusions of the SAMDA Evaluation

The Johnson Report states that rather than using the values in NUREG/BR-0184 to calculate replacement power costs, STPNOC should have used ERCOT pricing data.[96] However, even if ERCOT pricing data is used for the replacement power costs, the conclusions of the SAMDA evaluation would not be affected.[97]

The most recent annual ERCOT pricing data is for the year 2009.[98] As shown in the Joint Affidavit, even if STPNOC's replacement power costs are increased to account for the 2009 ERCOT pricing data, the resulting total monetized impacts are still well below the lowest cost of

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95 *See, e.g.*, Intervenors' Eleventh Update to Disclosures (Sept. 1, 2010).

96 Johnson Report at 3.

97 Joint Affidavit ¶¶ 33, 38.

98 *Id.* ¶ 32.

the SAMDAs.[99] Therefore, even using the 2009 ERCOT price of electricity for the replacement power costs, the conclusion that there are no cost-effective SAMDAs remains unchanged.[100]

In order to determine the sensitivity of the above conclusion to changes in ERCOT prices, the Joint Affidavit also performed a sensitivity analysis using ERCOT pricing data from the year with the highest prices since the ERCOT market was deregulated in 2002, which was 2008.[101] The prices in the 2008 ERCOT market were an outlier when compared to the other years since deregulation.[102] Significant transmission congestion, and the inefficient way by which congestion was relieved in ERCOT's zonal market structure, coupled with relatively strong natural gas prices, resulted in the elevated 2008 balancing energy prices.[103]

Nonetheless, as shown in the Joint Affidavit, even if STPNOC's replacement power costs are increased to account for these highest annual ERCOT pricing data, there is a substantial margin between the monetized impacts and the lowest cost of the SAMDAs, especially when the cost of the lowest-cost SAMDA is escalated to 2009 dollars ($158,000).[104] Therefore, the conclusion that there are no cost-effective SAMDAs is unaffected even if the highest ERCOT prices (*i.e.*, from 2008) are used to calculate the replacement power costs.[105]

In summary, there is no genuine issue of material fact that the use of ERCOT pricing data does not affect the conclusion that there is no cost-effective SAMDA. As the Supreme Court has held, "[o]nly disputes over facts *that might affect the outcome of the suit under the governing law*

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99 *Id.* ¶ 33; Statement of Material Facts § IV.A.

100 Statement of Material Facts § IV.A.

101 Joint Affidavit ¶ 35.

102 *Id.* ¶ 37.

103 *Id.*

104 *Id.* ¶ 38; Statement of Material Facts § IV.C.

105 Statement of Material Facts § IV.C.

will properly preclude the entry of summary judgment. Factual disputes that are irrelevant or unnecessary will not be counted."[106]

2. Use of the Intervenors' Replacement Power Costs Would Not Affect the Conclusions of the SAMDA Evaluation

The Intervenors have stated that the replacement power costs in the SAMDA evaluation should be based on a forecast of baseline ERCOT market prices rather than on the replacement power costs specified in NUREG/BR-0184.[107] The Intervenors rely upon the Johnson Report, which states that the replacement power costs using ERCOT prices "are roughly 3 to 3.8 times the $430 thousand/day cost used by the Applicant."[108]

Even if the replacement power cost values proposed in the Johnson Report were used, they would not impact the conclusions in the SAMDA analysis.[109] As shown in the Joint Affidavit, multiplying the replacement power cost estimates in ER Section 7.5S.5 by 3.8 to account for the Johnson Report results in total monetized impacts that are well below the lowest cost of the SAMDAs.[110] Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs were up to 3.8 times too low does not affect the conclusion that there are no cost-effective SAMDAs.[111] The same is true if the value of $63.19 per MWh from the Johnson Report is used for calculation of replacement power costs.[112]

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106 *Anderson*, 477 U.S. at 248 (emphasis added).

107 Intervenors' Request at 7; Johnson Report at 2-4.

108 Johnson Report at 4.

109 Joint Affidavit ¶ 41.

110 *Id.*; Statement of Material Facts § V.A.

111 Statement of Material Facts § V.A.

112 Joint Affidavit ¶ 42; Statement of Material Facts § V.B.

In summary, there is no genuine issue of material fact that the use of the Intervenors' pricing data does not affect the conclusion that there is no cost-effective SAMDA.[113]

3. Consideration of ERCOT Market Effects Would Not Affect the Conclusions of the SAMDA Evaluation

The Intervenors have stated:

> The Applicant's quantification of the replacement power costs in the event of a forced shutdown of nuclear units on the STP site is inadequate in that it does not take into account the increase of ERCOT market prices due to the market effects of a STP outage.[114]

The Intervenors rely upon the Johnson Report for this conclusion.[115] The Johnson Report does not quantify the change in replacement power costs due to these market effects, and states that the impact should be evaluated by the Applicant.[116]

For a number of reasons, the loss of the STP units would not have significant long-term market effects in the ERCOT region, and would not dramatically increase annualized replacement power costs.[117] First, the combined capacity of the four STP units (approximately 5,260 MWe) is less than the generation capacity represented by the 12.5% ERCOT reserve margin for peak load conditions.[118] Additionally, during most of the year, ERCOT also operates well below the peak hour demand.[119] Furthermore, the potential multi-year outages for the STP units would stimulate new generation sources to enter the market.[120] ERCOT has indicated that 5,022 MW of mothballed capacity will exist in 2015, which could be brought back into service

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113 *See Anderson*, 477 U.S. at 248.

114 Intervenors' Request at 8.

115 *Id.*

116 Johnson Report at 5.

117 Joint Affidavit ¶ 44.

118 *Id.*

119 *Id.* ¶ 45.

120 *Id.* ¶ 46.

and be used to offset some of the lost generation from STP Units 3 and 4.[121] For these reasons, ERCOT should have enough reserve margin to supply demand, even if all four STP units were to be off-line.[122]

Furthermore, when the market effects of the shutdown of the STP units are considered in the estimation of replacement power costs, it would not change the conclusions in the SAMDA evaluation.[123] As shown in the Joint Affidavit, the market effects can be estimated by the difference between the 2009 ERCOT prices if it is assumed that all four STP units are operating and the 2009 ERCOT prices if all four STP units are shut down for the entire year.[124] If the economic impact from this change in the market prices is added to the replacement power costs using the conservative 2008 ERCOT pricing data, then the total monetized impacts are still well below the lowest cost of the SAMDAs.[125] Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for market effects does not affect the conclusion that there are no cost-effective SAMDAs.[126]

The Johnson Report also states that the replacement power cost evaluation should not just account for the cost of replacement power, but should also account for the impacts to consumers due to the higher market prices.[127] As shown in the Joint Affidavit, the impact on the SAMDA evaluation from these consumer impacts can be determined by using the above market effect calculation due to losing the four STP units and scaling it up to account for the increased market

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121 *Id.*

122 *Id.* ¶¶ 43-46.

123 *Id.* ¶ 47.

124 *Id.* ¶¶ 47-53.

125 Statement of Material Facts § VI.B.

126 *Id.*

127 Johnson Report at 5.

price for the total generation in ERCOT.[128] When the costs to consumers are included in the total monetized cost, the costs are still below the lowest cost of the SAMDAs.[129] Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for impacts to consumers does not affect the conclusion that there are no cost-effective SAMDAs.[130]

In summary, there is no genuine issue of material fact that consideration of market effects, including impacts to consumers, does not affect the conclusion that there is no cost-effective SAMDA.[131]

4. Consideration of ERCOT Price Spikes Would Not Affect the Conclusions of the SAMDA Evaluation

The Intervenors have stated:

> The Applicant's Environmental Report is inadequate in that it does not evaluate or take into account the impacts on ERCOT consumers and the disruptive impacts of potential price spikes and grid outages, which could be triggered by the simultaneous shutdown of all four units at STP.[132]

The Intervenors rely upon the Johnson Report for this conclusion.[133] Although the Johnson Report does not quantify the change in replacement power costs due to these price spikes, it states that price spikes increased ERCOT average prices in 2008 by 20%.[134]

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128 Joint Affidavit ¶¶ 56-59.

129 Statement of Material Facts § VI.C.

130 *Id.*

131 *See Anderson*, 477 U.S. at 248.

132 Intervenors' Request at 9.

133 *Id.*

134 Johnson Report at 6.

Price spikes occur in ERCOT every year.[135] The price spikes are of short duration.[136] The short duration is due to ERCOT carrying responsive reserves, regulation reserves, and non-spin reserves, all of which are carried 24 hours a day to handle contingencies.[137] The impact of these price spikes on average prices was estimated by ERCOT to be between 10% and 20% from 2006 through 2009.[138] This price impact is already accounted for by ERCOT's average prices used in the evaluations discussed above.[139]

The potential for increases in ERCOT average market prices due to additional price spikes attributable to outages of the STP units would be limited by many of the same factors that would minimize other market effects of shutting down the four STP units, such as market adjustment, restoring mothballed capacity, reserve margins, and demand response.[140] Additionally, the historical price spikes primarily have been due to inefficient zonal management techniques rather than outages of generation stations, and those grid management techniques will no longer exist beginning December 1, 2010, when ERCOT is scheduled to implement a nodal market design.[141] A nodal market design provides improved dispatch efficiencies and unit specific management of transmission congestion, a significant improvement over today's zonal market design.[142]

However, even if additional price spikes were to increase ERCOT prices by an additional 20% beyond those already accounted for in the average ERCOT prices for 2008, there still would

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135 Joint Affidavit ¶ 61.

136 *Id.*

137 *Id.*

138 *Id.*

139 *Id.*

140 *Id.* ¶ 62.

141 *Id.* ¶ 63.

142 *Id.* ¶ 37.

be no change to the conclusions of the SAMDA evaluation.[143] As shown in the Joint Affidavit, even if the conservative 2008 ERCOT pricing data are increased by 20% to account for additional price spikes, and after accounting for the additional ERCOT market effects and impacts to consumers discussed above, the total monetized impacts are still below the lowest cost of the SAMDAs.[144] Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for price spikes does not affect the conclusion that there are no cost-effective SAMDAs.[145]

In summary, there is no genuine issue of material fact that consideration of price spikes does not affect the conclusion that there is no cost-effective SAMDA.[146]

5. Consideration of the Loss of the Grid Would Not Affect the Conclusions of the SAMDA Evaluation

The Johnson Report also states that the simultaneous loss of four STP units "could increase the likelihood of outages on the ERCOT grid which result in load shedding, or even uncontrolled blackouts."[147] Although the Johnson Report does not quantify the change in costs due to these grid outages, it states that the grid outages will increase the economic costs.[148]

As the Johnson Report states, the probability of an ERCOT grid outage following a shutdown of all four STP units "may not be high."[149] ERCOT is responsible for running the grid reliably and avoiding the loss of load.[150] In addition, since the Northeast United States Blackout

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143 Statement of Material Facts § VII.C.

144 Joint Affidavit ¶ 64; Statement of Material Facts § VII.C.

145 Statement of Material Facts § VII.C.

146 *See Anderson*, 477 U.S. at 248.

147 Johnson Report at 7.

148 *Id.*

149 *Id.*

150 Statement of Material Facts § VIII.A.

of 2003, ERCOT, as well as all other electricity regions in the United States, are under strict federally enforced reliability standards.[151] These rigorous standards are monitored and enforced by the Texas Reliability Entity, which has the responsibility of ensuring the reliability of the bulk power system as per the requirements of the North American Electric Reliability Corporation ("NERC").[152]

As explained in the Final Safety Analysis Report ("FSAR") Section 8.2.2.3 for STP Units 3 and 4,[153] the ERCOT grid is designed to simultaneously lose the two largest generators without a loss of the grid.[154] In the event of a severe accident at one STP unit, the other units would be shut down in an orderly fashion, *i.e.*, all four units would not be taken off the grid simultaneously.[155] Given the orderly shutdown, ERCOT would have time to adjust to the loss of the four units and to bring other generation sources online, invoke certain demand response programs, and shed load if necessary.[156]

Additionally, the low probability for loss of the grid also would be limited by many of the same factors that would minimize other market effects and price spikes due to shutting down the four STP units, such as market adjustment, restoring mothballed capacity, reserve margins, and demand response.[157] Given all of the protective measures established by ERCOT, the Texas Reliability Entity, and NERC, as discussed above, it is extremely unlikely that a shutdown of all four STP units would result in a loss of the ERCOT grid.[158] In fact, the protective measures have

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151 *Id.*

152 *Id.*

153 FSAR § 8.2.2.3 (Rev. 3, Sept. 2009), *available at* ADAMS Accession No. ML092931359.

154 Statement of Material Facts § VIII.A.

155 *Id.*

156 *Id.*

157 *Id.*

158 *Id.*

been successful in the past, and there has never been a loss of the entire ERCOT grid due to any event.[159]

As discussed above, the CDF for the ABWR is 1.56×10^{-7} per year.[160] Although it is difficult to quantify a probability for loss of the ERCOT grid due to shutdown of the four STP units, the Joint Affidavit states that the probability is far less than 0.1.[161] Thus, the probability of a severe accident at one of the ABWR units at the STP site, followed by a shutdown of the other three STP units, followed by a loss of the ERCOT grid, is far less than 10^{-8} per year.[162]

Given the very low probability of a severe accident, times the low probability that the STP shutdown would result in a loss of the grid, loss of the grid is a remote and speculative event. Consideration of such "remote and speculative" impacts is not required by NEPA.[163] As the Commission explained, "NEPA also does not call for certainty or precision, but an *estimate* of anticipated (not unduly speculative) impacts."[164] STPNOC has provided a very conservative estimation of replacement power costs for the co-located units; the speculative impacts of the unlikely loss of the grid are not required.

Consideration of the loss of the ERCOT grid would be akin to a worst-case analysis. It is well established that NEPA does not require a worst-case analysis.[165] The Commission has noted that the purpose of an EIS is to "inform the decisionmaking agency and the public of a broad range of environmental impacts that will result, with a fair degree of likelihood, from a

159 *Id.* § VIII.B.

160 *Id.* § I.F.

161 Joint Affidavit ¶ 71; Statement of Material Facts § VIII.C.

162 Statement of Material Facts § VIII.D.

163 *See Vermont Yankee*, ALAB-919, 30 NRC at 44.

164 *National Enrichment*, CLI-05-20, 62 NRC at 536.

165 *Robertson*, 490 U.S. at 359; *Private Fuel Storage, LLC* (Independent Spent Fuel Storage Installation), CLI-02-25, 56 NRC 340, 352 (2002).

proposed project, rather than to speculate about 'worst-case' scenarios and how to prevent them."[166] Similarly, the Commission recently stated in *Pilgrim* that "[a]s a mitigation analysis, NRC SAMA analysis is neither a worst-case nor a best-case impacts analysis."[167]

Furthermore, even if the impact of grid outages caused by the shutdown of the STP units is considered, it would not change the conclusions in the SAMDA evaluation.[168] As shown in the Joint Affidavit, the impact due to grid outages can be estimated by conservatively assuming that a grid outage similar to the 2003 Northeast blackout occurs with a $10 Billion impact as estimated in the Johnson Report.[169] If this impact is added to the replacement power costs using the conservative 2008 ERCOT pricing data, and accounting for the consumer impacts due to market effects and increases in price spikes, then the total monetized impacts are still below the lowest cost of the SAMDAs.[170] Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for grid outages does not affect the conclusion that there are no cost-effective SAMDAs.[171]

In summary, because consideration of a grid outage is not required by NEPA and consideration of grid outages does not affect the conclusion that there is no cost-effective SAMDA, there is no genuine issue as to any material fact with respect to this subject.

6. The Evaluation in the Joint Affidavit Is Very Conservative

The evaluation in the Joint Affidavit is very conservative.[172] For example, the Joint Affidavit: (1) assumes that the lowest-cost SAMDA will prevent all severe accidents; (2)

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166 *Private Fuel Storage*, CLI-02-25, 56 NRC at 347.

167 *Pilgrim*, CLI-10-11, slip op. at 38.

168 Statement of Material Facts § VIII.E.

169 Joint Affidavit ¶¶ 73-74.

170 Statement of Material Facts § VIII.E.

171 *Id.*

172 Joint Affidavit ¶ 76.

includes a sensitivity analysis for the replacement power cost estimates based on a 3% discount rate, which is far more conservative than the 7% discount rate typically used; (3) uses the 2008 ERCOT pricing data (highest prices since the ERCOT market was deregulated in 2002) as the basis for the replacement power cost estimates; (4) assumes that price spikes would occur due to the outages of the STP units (even though historical price spikes have often been due to grid congestion and not station outages) and that the price spikes would increase the market price by 20%; (5) assumes that a grid outage due to shutting down the STP units that is equivalent to the 2003 Northeast blackout occurs; and (6) assumes no discount rate when estimating the consumer impacts from market effects, price spikes, and grid outages.[173] Additionally, the Joint Affidavit does not only look at the separate impacts of the Intervenors' statements, it also evaluates the cumulative impact of all of the Intervenors' statements about issues that should be considered in calculating the replacement power costs.

This conservatism provides additional assurance for the conclusion that there are no cost-effective SAMDAs. This conservatism goes beyond the requirements of NEPA, which only requires that an evaluation be reasonable and does not require that a SAMDA analysis use worst case assumptions.[174]

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173 *Id.*

174 *See, e.g.*, *Pilgrim*, CLI-10-11, slip op. at 37.

VI. CONCLUSION

For the foregoing reasons, there is no genuine issue of material fact on Contention CL-2. Therefore, the Board should grant STPNOC's request for summary disposition of this contention.

Respectfully submitted,

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Counsel for STP Nuclear Operating Company

Dated in Washington, D.C.
this 14th day of September 2010

<u>CERTIFICATIONS</u>

I certify that I have made a sincere effort to contact the other parties in this proceeding, to explain to them the factual and legal issues raised in this motion, and to resolve those issues, and I certify that my efforts have been unsuccessful.

I also certify that this motion is not interposed for delay, prohibited discovery, or any other improper purpose, that I believe in good faith that there is no genuine issue as to any material fact relating to this motion, and that the moving party is entitled to a decision as a matter of law, as required by 10 C.F.R. §§ 2.1205 and 2.710(d).

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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
STP NUCLEAR OPERATING COMPANY	)	
	)	
(South Texas Project Units 3 and 4)	)	September 14, 2010

STATEMENT OF MATERIAL FACTS ON WHICH NO GENUINE ISSUE EXISTS IN SUPPORT OF STP NUCLEAR OPERATING COMPANY'S MOTION FOR SUMMARY DISPOSITION OF CONTENTION CL-2

STP Nuclear Operating Company ("STPNOC") submits, in support of its Motion for Summary Disposition of Contention CL-2, this Statement of Material Facts as to which there is no genuine issue to be heard.

I. Proposed Project

A. The South Texas Project ("STP") site is located on the coastal plain of southeastern Texas in Matagorda County.[1]

B. STPNOC is one of the licensees and is the operator for existing STP Units 1 and 2, which are pressurized water reactors located at the STP site.[2]

C. STPNOC has applied for combined licenses to construct and operate STP Units 3 and 4, two U.S. Advanced Boiling Water Reactors ("ABWRs"), at the STP site.[3]

1 Environmental Report ("ER") § 1.1.2.2 (Rev. 3, Sept. 2009), *available at* ADAMS Accession No. ML092931525.

2 *Id.* §§ 1.1, 1.1.2.1.

3 *Id.* § 1.1.1.

D. STP Units 3 and 4 each have a net electrical output rating of approximately 1350 MWe.[4]

E. STP Units 1 and 2 each have a net electrical output rating of approximately 1280 MWe.[5]

F. The core damage frequency ("CDF") for the ABWR is 1.56×10^{-7} per year for internal events at full power.[6]

G. External events at the STP site have a small contribution to the overall risk of STP Units 3 and 4.[7] Additionally, the probability of low power and shutdown events at STP Units 3 and 4 is low.[8] Accounting for the probability of external events and low power and shutdown events would not have a material impact on the total CDF for STP Units 3 and 4.[9]

II. <u>SAMDAs</u>

A. The costs of SAMDAs for designs certified under 10 C.F.R. Part 52 are determined as part of the design certification process.[10]

B. ABWR SAMDA costs were determined in the Technical Support Document ("TSD"), which was submitted as part of the ABWR design certification application.[11]

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4 *Id.* § 1.1.2.3.

5 *Id.* § 3.1.1 (Rev. 3, Sept. 2009), *available at* ADAMS Accession No. ML092931544.

6 Joint Affidavit ¶ 22.

7 *Id.*

8 *Id.*

9 *Id.*

10 *Id.* ¶ 12.

11 *Id.*

C. The lowest-cost SAMDA for an ABWR is $100,000 in 1991 dollars.[12] In 2008 or 2009 dollars, the lowest-cost SAMDA is $158,000.[13]

D. The lowest-cost SAMDA corresponds to improved vacuum breakers, drywell head flooding, and Reactor Building sprays.[14]

E. There are no SAMDAs for the ABWR that would prevent all severe accidents.[15]

F. There are no SAMDAs for STP Units 3 and 4 that could prevent or mitigate an accident at STP Units 1 and 2.[16]

III. STPNOC's SAMDA Evaluation in ER Sections 7.3 and 7.5S.5

A. ER § 7.3 includes an evaluation of Severe Accident Mitigation Alternatives ("SAMAs") involving administrative controls, such as procedures and training.[17] Evaluation and development of procedures and training does not need to occur until prior to fuel load.[18] Procedures and training will include appropriate provisions to mitigate accidents.[19]

B. STPNOC's estimation of replacement power costs for the SAMDA evaluation in ER §§ 7.3 and 7.5S.5 followed the guidance in NUREG/BR-0184, "Regulatory Analysis Technical Evaluation Handbook" (Jan. 1997).[20]

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12 *Id.*

13 *Id.* ¶ 30.

14 *Id.* ¶ 12.

15 *Id.* ¶ 14.

16 *Id.* ¶ 15; *see also* Letter from S. Head, STPNOC, to NRC, Proposed Revision to Environmental Report, Attachment, at 7 (Nov. 10, 2009) (filed as an attachment to Letter from S. Burdick, Counsel for STPNOC, to the Board, Notification of Filing Related to Contention 21 (Nov. 11, 2009)) ("ER Letter").

17 Joint Affidavit ¶ 10; ER § 7.3 (Rev. 3, Sept. 2009), *available at* ADAMS Accession No. ML092931583.

18 Joint Affidavit ¶ 10.

19 *Id.*; ER § 7.3 (Rev. 3, Sept. 2009), *available at* ADAMS Accession No. ML092931583.

20 Joint Affidavit ¶ 16; ER Letter, Attachment, at 7.

C. NUREG/BR-0184 provides typical short-term replacement power costs for a 910 MWe power plant of $310,000 per day (1993 dollars).[21]

D. For the analysis in ER §§ 7.3 and 7.5S.5, STPNOC multiplied the daily replacement power cost value in NUREG/BR-0184 by the estimated outage duration of the co-located units.[22]

   1. The estimated outage duration at the co-located ABWR is six years and the estimated outage duration at the co-located STP Units 1 and 2 is two years.[23]

   2. These estimates of outage durations are reasonable based upon the experience involving the outage of Three Mile Island Unit 1 following the accident at Unit 2 in 1979.[24]

E. For the analysis in ER §§ 7.3 and 7.5S.5, STPNOC assumed a discount rate of 7% (and 3% for a sensitivity analysis).[25]

   1. A long-term 7% discount rate is reasonable.[26]

F. For the analysis in ER § 7.5S.5:

   1. STPNOC scaled up the replacement power costs in NUREG/BR-0184 from a 910 MWe plant to a 1350 MWe plant for the ABWR and to 1280 MWe each for STP Units 1 and 2.[27]

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21 Joint Affidavit ¶ 21.

22 *Id.*

23 *Id.*; ER Letter, Attachment, at 7.

24 Joint Affidavit ¶ 21; ER Letter, Attachment, at 7.

25 Joint Affidavit ¶¶ 19, 22; ER Letter, Attachment, at 7.

26 Joint Affidavit ¶ 13.

27 *Id.* ¶ 22.

2. STPNOC used the CDF for internal events at full power for an ABWR to obtain probability-weighted costs for use in the SAMDA evaluation.[28]

G. To determine the total monetized costs for each unit for the analysis in ER §§ 7.3 and 7.5S.5, STPNOC added the replacement power costs to the other monetized impacts (*e.g.*, exposure cost and cleanup cost).[29]

H. The lowest cost of the SAMDAs is higher than the total monetized impacts of the accident, and therefore there are no cost-effective SAMDAs.[30]

IV. <u>ERCOT Cost Data</u>

A. If STPNOC's replacement power costs in ER §§ 7.3 and 7.5S.5 are increased to account for 2009 ERCOT pricing data, the resulting total monetized impacts are less than the lowest cost of the SAMDAs; *i.e.*, there are no cost-effective SAMDAs given these assumptions.[31]

B. After deregulation of the ERCOT markets in 2002, the highest annual ERCOT prices occurred in 2008.[32]

1. The prices in the 2008 ERCOT market were an outlier when compared to the other years since deregulation and are mainly attributable to significant transmission congestion and the inefficient way by which congestion was relieved in ERCOT's zonal market structure, coupled with relatively strong natural gas prices.[33]

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28 *Id.*; ER Letter, Attachment, at 7.

29 Joint Affidavit ¶¶ 19, 23.

30 *Id.* ¶¶ 24-25; ER Letter, Attachment, at 7.

31 Joint Affidavit ¶ 33.

32 *Id.* ¶ 35.

33 *Id.* ¶ 37.

2. The significant transmission congestion that occurred in 2008 is unlikely to be repeated, because ERCOT is changing its method for dispatching electricity and resolving transmission congestion beginning December 1, 2010, by implementing a nodal market design.[34]

C. If STPNOC's replacement power costs in ER §§ 7.3 and 7.5S.5 are increased to account for the ERCOT pricing data in 2008, the resulting total monetized impacts are less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions).[35]

V. <u>Intervenors' Replacement Power Cost Estimates</u>

A. Multiplying STPNOC's replacement power cost estimates in ER §§ 7.3 and 7.5S.5 by 3.8 to account for the Johnson Report results in a total monetized impact that is less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions).[36]

B. Increasing STPNOC's replacement power cost estimates in ER §§ 7.3 and 7.5S.5 to account for a cost of power of $63.19/MHh postulated in the Johnson Report results in a total monetized impact that is less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions).[37]

VI. <u>ERCOT Market Effects</u>

A. A shutdown of the four STP units would result in an increase in the ERCOT market prices.[38]

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34 *Id.*

35 *Id.* ¶ 38.

36 *Id.* ¶ 41.

37 *Id.* ¶ 42.

38 *Id.* ¶ 52.

B. If the economic impact of the change in the market prices due to shutdown of the STP units is added to the replacement power costs using the 2008 ERCOT pricing data, the total monetized impacts are less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions).[39]

C. If the consumer impacts due to increased ERCOT market prices from shutdown of the STP units are accounted for in the total monetized costs using the ERCOT pricing data in 2008, the total monetized impacts are less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions).[40]

VII. Price Spikes

A. Price spikes have occurred in ERCOT every year following deregulation of the market.[41] The price spikes have been of short duration, and the impact of price spikes on average prices was 10% to 20% in the years from 2006 through 2009, which is accounted for in the average annual ERCOT prices.[42]

B. The historical price spikes in ERCOT primarily have been due to inefficient zonal management techniques rather than outages of generating stations.[43] The inefficient zonal management technique will no longer exist beginning December 1, 2010, when ERCOT is scheduled to implement a nodal market design.[44]

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39 *Id.* ¶ 55.

40 *Id.* ¶ 58.

41 *Id.* ¶ 61.

42 *Id.*

43 *Id.* ¶ 63.

44 *Id.*

C. If it is assumed that the outages of the STP units would result in additional price spikes and that such spikes were to increase average ERCOT prices by an additional 20% beyond the 2008 ERCOT prices, the total monetized impacts would be less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions and accounting for the additional ERCOT market effects and impacts to consumers).[45]

VIII. Grid Outages

A. It is extremely unlikely that a shutdown of all four STP units would result in a loss of the ERCOT grid, because:

1. ERCOT is responsible for running the grid reliably and avoiding the loss of load.[46] ERCOT is under strict federally enforced reliability standards that are monitored and enforced by the Texas Reliability Entity, which has the responsibility of ensuring the reliability of the bulk power system as per the requirements of the North American Electric Reliability Corporation.[47]
2. The ERCOT grid is designed to simultaneously lose the two largest generators without a loss of the grid.[48]
3. In the event of a severe accident at one STP unit, the other units would be shut down in an orderly fashion, *i.e.*, all four units would not be taken off the grid simultaneously.[49]

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45 *Id.* ¶¶ 64-65.

46 *Id.* ¶ 67.

47 *Id.*

48 *Id.* ¶ 68.

49 *Id.*

4. ERCOT would adjust to the loss of the four STP units and bring other generation sources online, invoke certain demand response programs, and shed load if required.[50]

5. Market adjustments, restoring mothballed capacity, and reserve margins would limit the impact of loss of the STP units on the reliability of the ERCOT grid.[51]

B. There has never been a loss of the entire ERCOT grid due to any event.[52]

C. The probability for loss of the ERCOT grid due to shut down of the four STP units has not been calculated but is likely less than 0.1.[53]

D. The probability of a severe accident at one of the ABWR units at the STP site, followed by a shutdown of the other three STP units, followed by a loss of the ERCOT grid, is likely less than 10^{-8} per year.[54]

E. If it is assumed that the outages of the STP units would result in ERCOT grid outages, and if the costs to the public from the outages were added to the replacement power costs using 2008 ERCOT prices, the total monetized impacts would be less than the lowest cost of the SAMDAs (*i.e.*, there are no cost-effective SAMDAs given these assumptions and accounting for the additional ERCOT market effects and impacts to consumers and price spikes).[55]

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[50] *Id.*

[51] *Id.* ¶ 69.

[52] *Id.* ¶ 70.

[53] *Id.* ¶ 71.

[54] *Id.*

[55] *Id.* ¶¶ 72-74.

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
STP NUCLEAR OPERATING COMPANY	)	
(South Texas Project Units 3 and 4)	)	September 14, 2010

JOINT AFFIDAVIT OF JEFFREY L. ZIMMERLY AND ADRIAN PIENIAZEK

I. PERSONAL QUALIFICATIONS

1. **[J. Zimmerly]** My name is Jeffrey L. Zimmerly. I am currently an Environmental Engineer and the Corporate Quality Assurance Manager for Tetra Tech NUS, Inc. (Tetra Tech), which is a contractor to STP Nuclear Operating Company (STPNOC) for STP Units 3 and 4. I have more than 10 years of experience supporting various government, utility, and industrial clients in the areas of environmental impact assessment, radiological transportation risk assessment, accident analysis, human health and ecological risk assessment, air quality modeling and compliance, occupational and environmental health physics, and radioactive waste management.

2. I participated in the preparation of the Environmental Report (ER) for STP Units 3 and 4, including authoring and reviewing parts of the Severe Accident Mitigation Design Alternative (SAMDA) sections of the ER. I similarly authored and reviewed portions of the new ER Section 7.5S that STPNOC submitted to the NRC on November 10, 2009. I also have performed analyses and calculations to support ERs for other new reactor and license renewal applications.

3. I have been employed with Tetra Tech since May 2000. Prior to this employment, I was employed with Westinghouse and Carolina Power and Light Company. I earned a B.S. degree in health physics from Francis Marion University. A copy of my resume is attached to this Joint Affidavit as STP Attachment 1.

4. With respect to this Joint Affidavit, I prepared those sections that (1) discuss the replacement power costs estimated for ER Section 7.5S and the corresponding SAMDA evaluation; and (2) discuss the reasonableness of STPNOC's replacement power cost estimates. To more readily identify these sections, I have included my name within brackets (*i.e.*, [J. Zimmerly]) immediately preceding those sections I prepared.

5. **[A. Pieniazek]** My name is Adrian Pieniazek. I am currently the Director of Market Policy for NRG Texas LLC. I have more than 27 years of experience in the energy industry and I have been in my current position since 2003. My current responsibilities include representing NRG Texas' interests at the Electric Reliability Council of Texas (ERCOT) and the Public Utility Commission of Texas (PUCT) and providing analysis and policy recommendations to numerous NRG Texas business units, with a specific emphasis on wholesale electricity market design issues.

6. Prior to my current position, I was the Director of Asset Management for Reliant Energy, Inc. Prior to that, I served as the Director of Generation Planning for CPS Energy, the municipal power utility serving San Antonio, Texas. Upon graduation from college, I began my career serving in various engineering positions for TXU Energy (now Luminant Energy). I earned a B.S. degree in Mechanical Engineering from Texas A&M University and an M.B.A. from Our Lady of the Lake University in San Antonio, Texas. I am a registered professional engineer in Texas. A copy of my resume is attached to this Joint Affidavit as STP Attachment 2.

7. With respect to this Joint Affidavit, I prepared those sections that (1) discuss the reasonableness of STPNOC's replacement power cost estimates; (2) evaluate replacement power costs based on ERCOT pricing data; (3) demonstrate that use of the Intervenors' replacement power cost estimates (including the estimates provided in "Review of Replacement Power Costs For Unaffected Units At the STP Site" by Clarence L. Johnson (December 21, 2009) (Johnson Report)) would not change the SAMDA conclusions; and (4) discuss the impacts on replacement power costs in ERCOT due to a shutdown of all four STP units, including the effects on market prices, price spikes, and grid outages. To more readily identify these sections, I have included my name within brackets (*i.e.*, [A. Pieniazek]) immediately preceding those sections I prepared.

II. PURPOSE OF THE JOINT AFFIDAVIT

8. **[All]** The purpose of this Joint Affidavit is to:

- Provide an overview of the ER for STP Units 3 and 4 related to evaluation of SAMDAs, including the November 10, 2009 revisions (ER revisions) that created a new ER Section 7.5S that evaluates SAMDAs in the event of a severe accident that forces the co-located units to shut down.
- Demonstrate that the information provided by the Intervenors in their December 22, 2009 "Intervenors' Contentions Regarding Applicant's Proposed Revision to Environmental Report Section 7.5S and Request for Hearing," including the Johnson Report, and their January 29, 2010 "Intervenors' Consolidated Response to NRC Staff's Answer to the Intervenors' New Accident Contentions and Applicant's Answer Opposing New Contentions Regarding Applicant's Environmental Report Section 7.5S" is not inconsistent in any material respect with the conclusions in the ER and the ER revisions.

III. OVERVIEW OF THE ER SAMDA EVALUATION

9. **[J. Zimmerly]** ER Chapter 7 discusses the environmental impacts of postulated accidents. Specifically, ER Section 7.1 addresses design basis accidents; ER Section 7.2 addresses severe accidents; ER Section 7.3 addresses severe accident mitigation alternatives (SAMAs); and ER Section 7.4 addresses transportation accidents. On November 10, 2009, STPNOC submitted ER revisions that created a new ER Section 7.5S that evaluates the impacts of design basis and severe accidents on the co-located units at the STP site. I attest to the truthfulness and accuracy of ER Chapter 7 and the November 10, 2009 ER revisions and adopt them as part of this Joint Affidavit. I also attest to the truthfulness and accuracy of ER Sections 1.1 and 3.1.1.

10. ER Section 7.3 presents a site-specific analysis of SAMAs. SAMAs consist of two types of alternatives: 1) SAMDAs; and 2) alternatives involving administrative controls, such as procedures and training. With respect to the latter, ER Section 7.3.3 states that evaluation of specific administrative controls will occur when the design for STP Units 3 and 4 is finalized and plant administrative processes and procedures are being developed. Under the licensing process established in 10 C.F.R. Part 52, procedures and training do not need to be finalized in order to obtain a combined license and instead can be developed during construction. Prior to fuel load, appropriate administrative controls on plant operations will be developed and incorporated into the management systems for STP Units 3 and 4. Therefore, because procedures and training materials have not and do not need to be developed at this time, and because appropriate procedures and training to mitigate accidents will be developed before fuel load, there is no further evaluation of alternative administrative controls that can fruitfully be conducted at this time. As a result, only the evaluation of SAMDAs remains.

A. <u>Methodology for SAMDA Evaluations</u>

11. **[J. Zimmerly]** To perform a SAMDA evaluation, the cost of each SAMDA is compared against the benefit of implementing the SAMDA. If the maximum benefit from averting all severe accidents is greater than the lowest cost of the SAMDAs, then the SAMDA is considered further.

12. The costs of SAMDAs for designs certified under 10 C.F.R. Part 52 are determined as part of the design certification process. For the Advanced Boiling Water Reactor (ABWR), the design selected for STP Units 3 and 4, the SAMDA costs were determined in the Technical Support Document (TSD) submitted as part of the ABWR design certification application. The lowest-cost SAMDA for the ABWR was estimated to be $100,000 (1991 dollars) (STP Attachment 3). This lowest-cost corresponds to SAMDAs for improved vacuum breakers, drywell head flooding, and Reactor Building sprays.

13. The benefits of SAMDAs are determined using a probabilistic-based approach for estimating the maximum averted cost-risk of the severe accidents. This approach accounts for exposure costs, cleanup costs, and replacement power costs associated with the postulated severe accident and corresponding outages, and factors in the likelihood of the severe accident as demonstrated by the reactor's Core Damage Frequency (CDF). In calculating the benefits of SAMDAs (*i.e.*, the maximum averted cost-risk), it is assumed that the SAMDA would completely prevent all severe accidents. The cost of an accident is converted into a net present value using the discount rate. In general, a long-term 7% discount rate is reasonable (NUREG/BR-0184, page 5.21 (STP Attachment 4)); however, as part of a sensitivity analysis, STPNOC also conservatively assumed a 3% discount rate, which results in a significantly higher net present value.

14. This methodology of comparing the costs and benefits for a SAMDA is conservative, because in actuality there are no SAMDAs that would prevent all severe accidents, and therefore there will always be some cost-risk that cannot be averted. In other words, implementing a SAMDA will not realize all of the benefits of avoiding the severe accidents, but will only achieve a portion of those benefits. Therefore, if the benefits of a SAMDA are shown to be higher than the cost of a SAMDA using the above methodology, then further evaluation would be necessary to determine how much of the benefit actually would be achieved by implementing the SAMDA (*i.e.*, how much the severe accident risk would be reduced by the SAMDA).

However, for the sake of STPNOC's SAMDA analysis and the evaluation in this Joint Affidavit, it is conservatively assumed that the SAMDAs completely prevent all severe accidents.

15. Additionally, for purposes of STPNOC's SAMDA evaluation, accidents originating at STP Units 1 and 2 were not considered because there are no SAMDAs for STP Units 3 and 4 that could prevent or mitigate an accident at STP Units 1 and 2.

B. NUREG/BR-0184

16. **[J. Zimmerly]** STPNOC's estimation of replacement power costs for the SAMDA evaluation in ER Sections 7.3 and 7.5S.5 followed the guidance in NUREG/BR-0184, "Regulatory Analysis Technical Evaluation Handbook" (Jan. 1997) (STP Attachment 4). NUREG/BR-0184 provides NRC guidance for calculating replacement power costs. NUREG/BR-0184 states that its purpose "is to provide guidance to the regulatory analyst to promote preparation of quality regulatory analysis documents" and to provide "standardized methods of preparation and presentation of regulatory analyses." Additionally, NUREG/BR-0184 states that it provides guidance that "is consistent with NRC policy and, if followed, will result in an acceptable document." Furthermore, NUREG-1555, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants," permits use of NUREG/BR-0184 for SAMDA evaluations. Specifically, NUREG-1555, Section 7.3, states that "[r]egulatory positions and specific criteria necessary to meet the regulations" are provided in "NUREG/BR-0184 (NRC 1997b) with respect to the value impact methodology" (STP Attachment 5). Thus, NUREG/BR-0184 provides an accepted NRC methodology for use in SAMDA analyses.

17. Chapter 5 of NUREG/BR-0184 (STP Attachment 4) provides generic methodologies for estimating the value impact of certain activities. Section 5.7.6 includes estimation methodologies for the costs of damage to onsite property, including long-term replacement power costs (Section 5.7.6.2). Additionally, Section 5.7.7 discusses industry implementation of these cost estimates, including short-term replacement power costs (Section 5.7.7.1).

C. SAMDA Evaluation for Unit Experiencing Severe Accident

18. **[J. Zimmerly]** The SAMDA analysis in ER Section 7.3 for the unit experiencing a severe accident is based upon the generic SAMDA evaluation for the ABWR design certification, which was contained in the TSD and has finality in accordance with Section VI.B.7 of the ABWR design certification rule in Appendix A to 10 C.F.R. Part 52. As discussed above, the TSD evaluated various SAMDAs, and determined that the least expensive SAMDA would cost $100,000 (1991 dollars) (STP Attachment 3). The TSD also evaluated the net present value of the cost of accidents, including replacement power costs and non-replacement power costs (such as land contamination and the monetary value of population doses), and it concluded that there are no cost-effective SAMDAs. As shown in ER Section 7.3, the TSD conclusion holds for the STP site.

19. ER Section 7.3.3 provided a monetary valuation of the cost-risk of accidents at STP Units 3 and 4, including replacement power costs and non-replacement power costs. As shown in ER Table 7.3-1, the net present value (2007 dollars) of the total maximum averted cost-risk for one ABWR is approximately $6,900 (assuming a 7% discount rate) and $12,500 in the sensitivity analysis (assuming a 3% discount rate). These values included replacement power costs of $4,400 (7% discount rate) and $7,400 in the sensitivity analysis (3% discount rate). The remaining costs included exposure and cleanup costs. STPNOC used guidance in NUREG/BR-0184 to perform these evaluations. ER Section 7.3.3 concluded that, using the maximum averted cost-risk for an ABWR at the STP site, the results of the SAMDA analysis for the ABWR would not be affected; *i.e.*, there would be no cost-effective design alternatives.

D. SAMDA Evaluation for Co-Located Units

20. **[J. Zimmerly]** As discussed above, STPNOC submitted revisions to the ER for STP Units 3 and 4 on November 10, 2009. These revisions created a new ER Section 7.5S, "Design Basis Accident or Severe Accident Impact on Other STP Units." ER Section 7.5S.5 evaluates the economic impacts of a temporary shutdown of the co-located STP units that do not experience the postulated severe accident. Similar to ER Section 7.3, the evaluation in ER Section 7.5S.5 was based upon the maximum averted cost-risk. The monetized impacts are shown in Tables 7.5S-1 and 7.5S-2 and include onsite exposure costs, onsite cleanup costs, and replacement power costs. The replacement power costs were calculated using information in NUREG/BR-0184. ER Section 7.5S.5 concludes that "[n]one of the severe accident mitigation design alternatives considered for the ABWR would be cost effective and mitigate the potential impacts (contamination and down time) from a large release severe accident at the existing units."

21. Section 5.7.7.1 of NUREG/BR-0184 states that typical short-term replacement power costs for a 910 MWe power plant are $310,000 per day (1993 dollars) (STP Attachment 4). To determine replacement power costs for the co-located units following a severe accident at the STP site, this value was first multiplied by the estimated outage duration of the co-located units. For a hypothetical severe accident at an ABWR unit, ER Section 7.5S.5 states that the estimated outage duration at the co-located ABWR is six years. Similarly, for this same postulated accident, ER Section 7.5S.5 states that the estimated outage duration at the co-located STP Units 1 and 2 is two years. These assumptions regarding outage duration are reasonable given the actual experience at Three Mile Island Unit 1 following the accident at Unit 2 in 1979.

22. These generic replacement power costs were then used in an equation specified in Section 5.7.6.2 of NUREG/BR-0184 (STP Attachment 4) to calculate the net present value of replacement power over the life of the facility. Finally, the specific net present value of replacement power over the life of the facility was scaled up from a 910 MWe plant to the 1350 MWe ABWR and multiplied by the CDF for the ABWR. For an ABWR, the CDF for internal events at full power is 1.56×10^{-7} per year. As discussed in ER Section 7.5S, external events at the STP site have a small contribution to risk. Additionally, the probability of low power and shutdown events is low. Accordingly, accounting for the probability of those categories of events would not have a material impact on the results of the SAMDA evaluation. For an accident originating at one of the ABWR units, using a CDF of 1.56×10^{-7} per year and a 7% discount rate resulted in a replacement power cost estimate of $1,980. Using a discount rate of 3% in the sensitivity analysis, the replacement power cost was estimated to be $2,557. Using a similar process, the replacement power costs at STP Units 1 or 2 (which produce approximately 1280 MWe each) were estimated to be $688 for a 7% discount rate and $1,153 for the sensitivity analysis using a 3% discount rate.

23. The replacement power costs calculated above were added to the other monetized impacts (*e.g.*, onsite exposure cost and onsite cleanup cost) to provide the total monetized impacts for each unit. A similar process was used for the unit experiencing the accident, as discussed in ER Section 7.3. These monetized impacts can be separated into replacement power costs and non-replacement power costs. As stated in ER Tables 7.3-1 and 7.5S-2, these total monetized impacts were estimated to be:

Table 1 – Monetized Impacts Using NUREG/BR-0184 Replacement Power Costs in 1993 Dollars

7% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$4,400	$1,980	$688	$688
Unit Total	$6,854	$3,005	$1,759	$1,759
Site Total	$13,377			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$7,400	$2,557	$1,153	$1,153
Unit Total	$12,446	$4,473	$3,048	$3,048
Site Total	$23,015			

24. The estimated monetized costs for each of the co-located units are less than half of the costs for the ABWR that experiences a severe accident. Furthermore, as concluded in ER Section 7.5S.5: "The Section 7.3 conclusion that there is no cost-effective ABWR operation design change holds for the mitigation of impacts at other site units."

25. In other words, the total monetized costs for the severe accident at an ABWR unit are calculated by summing the monetized costs for the ABWR experiencing the outage, the other ABWR, and STP Units 1 and 2. Using the 7% discount rate, the total monetized costs are $6,854 + $3,005 + $1,759 + $1,759 = $13,377 (in 1993 dollars). Using the more conservative values for the 3% discount rate in the sensitivity analysis, the total monetized costs are $12,446 + $4,473 + $3,048 + $3,048 = $23,015 (in 1993 dollars). As noted above, the lowest-cost SAMDA for the ABWR is $100,000 (in 1991 dollars). This value is much higher than the total monetized impacts of the accident; therefore, STPNOC concluded that there are no cost-effective SAMDAs.

IV. REASONABLENESS OF STPNOC'S REPLACEMENT POWER COST ESTIMATES

26. **[All]** For several reasons, STPNOC's use of the methodology set forth in NUREG/BR-0184 to estimate replacement power costs was reasonable.

27. First, NUREG/BR-0184 is NRC's standard methodology for cost-benefit analyses. In particular, NUREG/BR-0184 is specifically allowed by NUREG-1555 for the performance of SAMDA evaluations (STP Attachment 5). In this regard, forecasting replacement power 40 years into the future is speculative under any circumstances. By using the generic replacement power costs in NUREG/BR-0184, an applicant can avoid the need to speculate about local or regional replacement power costs and use a standard nation-wide value.

28. Second, NUREG/BR-0184 specifies replacement power costs from a similar time period as the SAMDA analysis for the ABWR. As noted above, the ABWR SAMDA costs from the TSD are provided in 1991 dollars (STP Attachment 3). The replacement power costs in NUREG/BR-0184 that STPNOC relied upon are provided in 1993 dollars (STP Attachment 4). Therefore, these costs are from similar years and can be compared. In contrast, the replacement power costs in the Johnson Report (page 4) are in 2008 dollars, which should not be directly compared to the ABWR SAMDA costs from 17 years earlier. When the NUREG/BR-0184 replacement power costs are escalated to account for inflation, the corresponding cost is $449,500 per day for a 910 MWe plant in 2008 dollars (using a 1.45 producer price index-commodities Bureau of Labor Statistics multiplier), or $20.58 per MWh in 2008 dollars. The replacement power cost estimates are substantially higher when reported in 2008 dollars and are closer to those in the Johnson Report.

29. Third, even if the replacement power costs are escalated to 2009 dollars to account for inflation, there is still no change to STPNOC's conclusions. When the NUREG/BR-0184 replacement power costs used by STPNOC are escalated to account for inflation, the corresponding cost is $452,600 per day for a 910 MWe plant in 2009 dollars (using a 1.46 producer price index-commodities Bureau of Labor Statistics multiplier), or $20.72 per MWh in 2009 dollars. Escalating the replacement power costs in Table 1 to 2009 dollars results in the following values:

Table 2 – Monetized Impacts Using NUREG/BR-0184 Replacement Power Costs Escalated to 2009 Dollars

7% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$6,424	$2,891	$1,004	$1,004
Unit Total	$8,878	$3,916	$2,075	$2,075
Site Total	$16,945			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$10,804	$3,733	$1,683	$1,683
Unit Total	$15,850	$5,649	$3,578	$3,578
Site Total	$28,656			

These values are still well below the lowest cost of the SAMDAs.

30. Finally, as noted above, the lowest-cost SAMDA in the TSD is $100,000 in 1991 dollars. The conversion factor from 1991 dollars to both 2008 or 2009 dollars using the consumer price index Bureau of Labor Statistics is 1.58. Thus, in 2008 or 2009 dollars, the lowest-cost SAMDA is $158,000. This increased SAMDA cost provides even more margin between the costs and benefits of the SAMDA evaluation.

V. INTERVENORS' POSITIONS ARE BOUNDED BY STPNOC'S CONCLUSIONS

A. ERCOT Pricing Data

1. 2009 ERCOT Pricing Data

31. **[A. Pieniazek]** The Johnson Report (page 3) states that STPNOC should have used ERCOT pricing data for calculating replacement power costs, rather than using the generic replacement power costs specified in NUREG/BR-0184. However, even if ERCOT pricing data is used for the replacement power costs, the conclusions of the SAMDA evaluation would not be affected.

32. The most recent annual ERCOT pricing data is for the year 2009. Potomac Economics, the Independent Market Monitor for the ERCOT Wholesale Market, published the "2009 State of the Market Report for the ERCOT Wholesale Electricity Markets" (2009 SOM Report) in July 2010 (STP Attachment 6). Pursuant to the requirements in Section 39.1515(h) of the Public Utility Regulatory Act, this report reviews and evaluates the outcomes of the ERCOT markets in 2009 and is submitted to the PUCT and ERCOT. According to the 2009 SOM Report (page v), the 2009 average balancing market price in ERCOT was $34.03 per MWh across ERCOT and was $34.76 per MWh in the ERCOT Houston zone where the STP site is located.

33. As discussed above, when the NUREG/BR-0184 replacement power costs used by STPNOC are escalated to account for inflation, the corresponding price is $20.72 per MWh in 2009 dollars. Therefore, the $34.76 per MWh from the 2009 SOM Report is 1.68 times larger than the NUREG/BR-0184 replacement power costs used by STPNOC in 2009 dollars. Multiplying the replacement power costs in Table 2 by 1.68 to account for the 2009 ERCOT pricing data results in the following values:

Table 3 – Monetized Impacts Using Replacement Power Costs Based on 2009 ERCOT Pricing Data (In 2009 Dollars)

7% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$10,775	$4,849	$1,685	$1,685
Unit Total	$13,229	$5,874	$2,756	$2,756
Site Total	$24,615			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$18,122	$6,262	$2,824	$2,824
Unit Total	$23,168	$8,178	$4,719	$4,719
Site Total	$40,783			

These values are still well below the lowest cost of the SAMDAs. Therefore, even using the 2009 ERCOT price of electricity for the replacement power costs, the conclusion that there are no cost-effective SAMDAs remains unchanged.

34. It is reasonable to use the replacement power costs in 2009 dollars, rather than attempt to forecast future energy prices throughout the life of the STP units, as long as the replacement power costs and SAMDA costs are from the same year. Using current or historical data, instead of forecasted data, removes much of the speculation from the SAMDA evaluation.

2. Sensitivity Analysis Using 2008 ERCOT Pricing Data

35. **[A. Pieniazek]** In order to determine the sensitivity of the above conclusion to changes in ERCOT prices, we also performed a sensitivity analysis using ERCOT pricing data from the year with the highest prices since the ERCOT market was deregulated in 2002. That year was 2008.

36. In summary, our conclusions are unchanged even if ERCOT pricing data is used from the highest price year. In August 2009, Potomac Economics, the Independent Market Monitor for the ERCOT Wholesale Market, published the "2008 State of the Market Report for the ERCOT Wholesale Electricity Markets" (2008 SOM Report) (STP Attachment 7). According to the 2008 SOM Report (page iii), the 2008 average balancing market price in ERCOT was $77.19 per MWh across ERCOT and was $82.95 per MWh in the ERCOT Houston zone where the STP site is located.

37. The prices in the 2008 ERCOT market were an outlier when compared to the other years since deregulation. Significant transmission congestion in April, May, and June, and the inefficient way by which congestion was relieved in ERCOT's zonal market structure, coupled with relatively strong natural gas prices, resulted in the elevated 2008 balancing energy prices. As a comparison, the 2009 average balancing market price across ERCOT was $34.03 per MWh (2009 SOM Report, page v) and the 2007 average balancing market price across ERCOT was $56.35 per MWh (2009 SOM Report, page v). These prices are much lower than the 2008 data. Furthermore, the significant transmission congestion that occurred in 2008 is unlikely to be repeated, because ERCOT is changing its method for dispatching electricity beginning December 1, 2010, to implement a nodal wholesale market design. A nodal market design provides improved dispatch efficiencies and unit specific management of transmission congestion, a significant improvement over today's zonal market design.

38. As discussed above, when the NUREG/BR-0184 replacement power costs used by STPNOC are escalated to account for inflation, the corresponding price is $20.72 per MWh in 2009 dollars. Therefore, assuming that the $82.95 per MWh from the 2008 SOM Report occurred in 2009, it is 4.00 times larger than the NUREG/BR-0184 replacement power costs used by STPNOC in 2009 dollars. Multiplying the replacement power costs in Table 2 by 4.00 to account for the 2008 ERCOT pricing data results in the following values:

Table 4 – Monetized Impacts Using Replacement Power Costs Based on the Highest Historical Annual ERCOT Pricing Data from 2008 (In 2009 dollars)

	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
7% Discount Rate				
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$25,713	$11,571	$4,021	$4,021
Unit Total	$28,167	$12,596	$5,092	$5,092
Site Total	$50,947			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$43,245	$14,943	$6,738	$6,738
Unit Total	$48,291	$16,859	$8,633	$8,633
Site Total	$82,416			

These values are still below the lowest cost of the SAMDAs. There is a substantial margin between the monetized impacts and the lowest cost of the SAMDAs, particularly when the cost of the lowest-cost SAMDA is escalated to 2009 dollars ($158,000). Therefore, the conclusion that there are no cost-effective SAMDAs is unaffected even if the highest ERCOT prices (*i.e.*, from 2008) are used to calculate the replacement power costs.

B. <u>Intervenors' Replacement Power Cost Estimates</u>

39. **[A. Pieniazek]** The Intervenors have stated that the replacement power costs in the SAMDA evaluation should be based on a forecast of baseline ERCOT market prices rather than on the replacement power costs specified in NUREG/BR-0184. The Intervenors rely upon the Johnson Report, which states (page 4) that the replacement power costs in ER Section 7.5S.5 "are roughly 3 to 3.8 times the $430 thousand/day cost used by the Applicant," and that a price of $60.01 to $63.19 per MWh in 2020-2025 would be more appropriate.

40. As discussed above, part of the difference between the replacement power costs in ER Section 7.5S.5 and the replacement power costs estimated in the Johnson Report are attributable to changes in energy prices over time. In particular, the replacement power costs in NUREG/BR-0184 are in 1993 dollars and the SAMDA costs in the TSD are in 1991 dollars. The Johnson Report, on the other hand, uses 2008 dollars. Since 1991 and 1993, there have been changes to energy prices that account for some of the discrepancies between the replacement power cost estimates in ER Section 7.5S.5 and those in the Johnson Report.

41. Nonetheless, even if the replacement power cost values proposed in the Johnson Report were used, they would not impact the conclusions in the SAMDA analysis. Multiplying replacement power cost estimates in ER Section 7.5S.5 (which are reproduced in Table 1 above) by 3.8 to account for the Johnson Report results in the following values:

Table 5 –Monetized Impacts Using Replacement Power Costs Based on the Johnson Report (in 2008 dollars)

7% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$16,720	$7,524	$2,614	$2,614
Unit Total	$19,174	$8,549	$3,685	$3,685
Site Total	$35,094			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$28,120	$9,717	$4,381	$4,381
Unit Total	$33,166	$11,633	$6,276	$6,276
Site Total	$57,351			

These values are well below the lowest cost of the SAMDAs. Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs were up to 3.8 times too low does not affect the conclusion that there are no cost-effective SAMDAs.

42. Additionally, the SAMDA evaluation in this Joint Affidavit completely bounds the pricing values provided by the Intervenors. For example, the Johnson Report (page 4) assumes that the average price per MWh for 2020-2025 is $60.01 to $63.19. This is well under the $82.95 per MWh considered above based on the 2008 ERCOT pricing data. A comparison of the replacement power costs in Table 5 using the Intervenors' data with the replacement power costs in Table 4 using 2008 ERCOT pricing data further demonstrates that this Joint Affidavit bounds the Intervenors' information.

C. ERCOT Market Effects

43. **[A. Pieniazek]** The Intervenors also have stated that the estimated replacement power costs in ER Section 7.5S are low because they do not account for the market effects in the ERCOT region due to the shutdown of the STP units following a severe accident scenario. They have also stated that the SAMDA analysis should account for the impact on consumers from the higher price of electricity due to the outage of the four STP units. The Johnson Report (page 5) does not quantify the change in replacement power costs due to these market effects, and states that the impact should be evaluated by the Applicant. Such an evaluation is provided below.

44. For a number of reasons, the loss of the STP units would not have significant long-term market effects in the ERCOT region, and would not dramatically increase annualized replacement power costs. First, ERCOT has a target of maintaining a 12.5% reserve margin above its peak hour demand to maintain adequate reserves to reliably meet ERCOT contingencies. The ERCOT reserve margin at the peak hour is calculated as (Resources – Firm Load Forecast)/(Firm Load Forecast). In 2015, when the first STP ABWR unit might commence operation, ERCOT predicted in its May 2010 "Report on the Capacity, Demand, and Reserves in the ERCOT Region" (STP Attachment 8) that the peak Firm Load Forecast will be 68,672 MW. A 12.5% reserve margin would require approximately 8,584 MW more Resources than Firm Load Forecast. The four STP units will have a combined capacity of approximately 5,260 MWe (approximately 1,350 MWe each for STP Units 3 and 4 and 1,280 MWe each for STP Units 1 and 2), which is less than the generation represented by the reserve margin. Thus, ERCOT should have enough installed capacity to supply demand, even if all four STP units were to be off-line. In this regard, operators of generating stations plan to have their plants available during peak periods, because they can earn a greater return during such periods.

45. Additionally, during most of the year, ERCOT operates well below the peak hour demand described above. Thus, for most of the operating hours in a year there should be sufficient capacity to replace the STP units. Additionally, in the years after 2015, ERCOT predicts that its Firm Load Forecast will increase, which in turn should result in an increase in the amount of capacity available to meet the increased demand. Therefore, in the years after 2015, a loss of all four STP units should have an even less impact on the ERCOT system.

46. Furthermore, while loss of the four STP units could have some impact on ERCOT market prices in the short term, the potential multi-year outages for the units would stimulate new generation sources to enter the market. In particular, new combined cycle generation units likely would enter the market if a multi-year outage is expected, and simple cycle generation units could enter even faster. Based on my experience, a simple cycle generation unit could be brought on-line in about a year. Additionally, ERCOT indicated in its May 2010 "Report on the Capacity, Demand, and Reserves in the ERCOT Region" (STP Attachment 8, page 9) that it will have 5,022 MW of mothballed capacity in 2015. This mothballed capacity could be brought back into service and be used to offset some of the lost generation from STP Units 3 and 4. My experience is that these mothballed units can typically be placed back in service within a month or two, depending on how long they have been in mothball status and the procedures used when placing them in mothball status. These units may be higher cost than the lost STP nuclear units, but the addition of this generation would minimize the market effects.

47. Aside from the above factors that would offset some of the market effects of shutting down the four STP units, even if these market effects are considered in the estimation of replacement power costs, it would not change the conclusions in the SAMDA evaluation. To quantify the effect on ERCOT replacement power costs due to a severe accident scenario, I developed a simplified dispatch model that compares the annual load-weighted average wholesale market price under two scenarios: 1) the price with all four STP units available, and 2) the price with all four STP units removed from service. Since the price of electricity in ERCOT varies significantly depending upon the loads and available generating units (which in turn vary over the course of a year), my model accounted for that variation over the course of a full year.

48. The dispatch model was developed using publicly available data. The first set of data included in the model was the list of generating units in ERCOT and their corresponding summer capacities from ERCOT's May 2010 "Report on the Capacity, Demand and Reserves in the ERCOT Region" (STP Attachment 8). Each unit was then categorized into one of fifteen different technology types (renewable, nuclear, coal and lignite, combined cycle, etc.) as described in ERCOT's zonal protocols. Once categorized, the units were assigned a generic fuel cost, also described in ERCOT's protocols (August 1, 2010 ERCOT Protocols, Section 6, Ancillary Services) (STP Attachment 9), and then ranked in "dispatch order" based on these costs. Renewable units were the first units in the dispatch order, with a generic fuel cost of $0 per MWh, hydro units were next at $10 per MWh, nuclear units next at $15 per MWh, coal and lignite at $18 per MWh, followed by the natural gas-fired units, which were assigned a heat rate times a fuel index price based on their technology type. Completing the dispatch order were technology types that are used infrequently because of their relatively expensive underlying costs (diesels, loads shedding resources, etc.).

49. Once the unit dispatch ranking was completed, each unit's capacity was corrected by availability and/or capacity factors obtained from ERCOT and the North American Electric Reliability Corporation (NERC). For example, ERCOT's website provides information on the actual output of the wind units for each hour in 2009. A comparison of the actual energy output from the wind units to their installed capacity resulted in an average annual capacity factor of 24.5%. Thus, the net capacity of all wind units in the model was designated to be 24.5% of actual installed capacity. For all other unit types, equivalent availability factors were obtained from NERC's Generation Availability Reports for 2005-2009 and each unit's capacity was reduced accordingly.

50. The final data input to the model is ERCOT's actual load demand by hour for 2009, which varies significantly by time of day and time of year. Since ERCOT also carries ancillary services every hour of every day, an average value for responsive reserves, non-spinning reserves, and regulation reserves was also added to the actual load.

51. With the data inputs complete, the model's algorithms then "dispatch" the ranked units to meet the load and reserve requirements for each hour in 2009. The model results in a determination of the marginal unit, and the corresponding marginal price, for each hour of 2009, based on the generic costs described previously. Use of the marginal price is appropriate, because the wholesale power price in ERCOT is based on the cost of the last unit dispatched. Once the hourly marginal price is determined, the model then calculates the load-weighted average price in ERCOT for the year.

52. Based on the 2009 average natural gas price of $3.74 per MMBtu (2009 SOM Report, page iv) and the preceding assumptions and methodology, the dispatch model indicates the loss of all four STP units would increase the load-weighted average annual market price in ERCOT by $1.80 per MWh. With all four STP units available, the load-weighted average annual market price was $36.06 per MWh. With all four STP units removed from service, the load-weighted average annual market price increased to $37.86 per MWh. These results are not surprising because the units on the margin for the vast majority of hours during the year are natural-gas fired, with or without the STP units.

53. As a check on the accuracy of my simplified model, I compared the average prices with all four STP units available ($36.06 per MWh) with the actual average balancing market price in ERCOT for 2009 ($34.03 per MWh). My calculated price was close to (and slightly higher than) the actual average price. This provides confidence that my model produces reasonable results. Furthermore, since the purpose of my model was to calculate the difference in market prices with and without the four STP units, the magnitude of the average price is not critical.

1. Impact on Replacement Power Costs

54. **[A. Pieniazek]** To determine the impact of these market effects on the SAMDA evaluation, the increase in price due to shutting down the four STP units is added to the 2008 average balancing price. As discussed above, the 2008 SOM Report provides an average balancing price of $82.95 per MWh. If this amount is increased by $1.80 per MWh to account for the market effects of shutting down the four STP units, the resulting price is $84.75 per MWh. This price is 4.09 times larger than the $20.72 per MWh price when the NUREG/BR-0184 replacement power costs used by STPNOC are escalated to 2009 dollars to account for inflation.

55. Multiplying the replacement power costs in Table 2 by 4.09 to account for the 2008 ERCOT pricing data and to account for market effects results in the following values:

Table 6 – Monetized Impacts Using Replacement Power Costs Based on 2008 ERCOT Pricing Data and Accounting for Market Effects

7% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$2,454	$1,025	$1,071	$1,071
Replacement Power Costs	$26,271	$11,822	$4,108	$4,108
Unit Total	$28,725	$12,847	$5,179	$5,179
Site Total	$51,930			
Sensitivity Analysis -- 3% Discount Rate				
	ABWR with Severe Accident (ER Table 7.3-1)	**Other ABWR (ER Table 7.5S-2)**	**STP Unit 1 (ER Table 7.5S-2)**	**STP Unit 2 (ER Table 7.5S-2)**
Non-Replacement Power Costs	$5,046	$1,916	$1,895	$1,895
Replacement Power Costs	$44,184	$15,267	$6,884	$6,884
Unit Total	$49,230	$17,183	$8,779	$8,779
Site Total	$83,972			

These values are still well below the lowest cost of the SAMDAs. Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for market effects does not affect the conclusion that there are no cost-effective SAMDAs. Additionally, use of the 2008 rather than the 2009 average balancing price in this analysis is very conservative. This evaluation also is conservative because it assumes that the higher market price lasts throughout the shutdown period, when in reality the effects would be mitigated based on the factors discussed above.

2. Impact on Consumers

56. **[A. Pieniazek]** The Johnson Report (page 5) also discusses a sensitivity analysis to illustrate the impacts on consumers within ERCOT of any increase in market price due to shutdown of the four STP units. The Johnson Report, however, does not provide an actual evaluation of the impacts. Instead, it arbitrarily picks a $10 increase in ERCOT market prices, and states that such an increase would produce a $3.8 billion annual cost to consumers. As stated above, the calculated increase in annual ERCOT market prices due to shutting down the four STP units is $1.80 per MWh, which is much lower than the arbitrarily selected value in the Johnson Report.

57. The impact to consumers can be approximated using the total ERCOT generation in 2009 and the $1.80 per MWh increase in market prices calculated above. As shown in the 2009 ERCOT Hourly Load Data publication, the total generation in ERCOT in 2009 was 307,491,044 MWh. Therefore, the economic impact of the increased market price is $553,483,879 per year. Once the probability of the severe accident is accounted for with the CDF (1.56×10^{-7} per year), the resulting impact is $86.34 per year-squared. Accounting for a 40 year life of the plant and conservatively assuming that the increased market price lasts for six years, the overall economic impact is $20,722. This calculation conservatively does not account for the discount rate.

58. When this $20,722 consumer impact due to market effects is added to the total monetized impacts in Table 4 using the 7% discount rate ($50,947), the resulting monetized impacts are $71,669. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $103,139. These values are still below the lowest cost of the SAMDAs ($158,000 in 2009 dollars). Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for impacts to consumers does not affect the conclusion that there are no cost-effective SAMDAs.

59. In summary, even if both the ERCOT market effects from using more expensive generation units and the impacts on consumer prices due to shutdown of the STP units are considered, there still is no cost-effective SAMDA.

D. <u>ERCOT Price Spikes</u>

60. **[A. Pieniazek]** The Intervenors also have stated that the replacement power costs should consider additional price spikes that could occur due to the shutdown of the four STP units.

Although the Johnson Report does not quantify the change in replacement power costs due to these price spikes, it states that price spikes increased ERCOT average prices in 2008 by 20%.

61. As discussed in the 2009 SOM Report (pages 6-7), price spikes are defined as intervals where the load-weighted average Market Clearing Price of Energy in ERCOT is greater than 18 MMbtu per MWh times the prevailing natural gas price (a level that should exceed the marginal costs of virtually all of the on-line generators in ERCOT). Based on this definition, price spikes have occurred in ERCOT every year following deregulation of the market. There were 99, 52, 62, and 64 price spikes per month in 2006, 2007, 2008, and 2009, respectively. As shown by the zonal price duration curves in the 2009 SOM Report (page 6), the price spikes are of short duration and only increased prices above $50 per MWh for a few hundred hours a year total. The short duration is due to ERCOT carrying responsive, regulation, and non-spin reserves, all of which are carried 24 hours a day to handle contingencies. The impact of these price spikes on average prices was estimated to be 10%, 11%, 20%, and 18% in 2006, 2007, 2008, and 2009, respectively (2009 SOM Report, page 6). This price impact is already accounted for by the average balancing prices in Tables 3 and 4 above.

62. The potential for increases in ERCOT average market prices due to additional price spikes attributable to outages of the STP units would be limited by many of the same factors that would minimize other market effects of shutting down the four STP units. For example, as acknowledged in the Johnson Report (page 6), the ERCOT market would adjust to the loss of the STP units and would diminish the impact of price spikes. This would occur as new units enter the market to replace the generation from the STP units. ERCOT also will have approximately 5,022 MW of mothballed capacity that could potentially replace the lost generation. As discussed above, the generation from all four STP units also is less than the 12.5% reserve margin in ERCOT, which was calculated on the peak hour of the year. Therefore, in most, if not all hours of the year, ERCOT should have enough operating reserves to ensure adequate protection against the loss of load. These operating reserves naturally suppress price spikes.

63. Additionally, the price spikes in the highest priced year of 2008 were primarily due to inefficient zonal management techniques rather than outages of generating stations. The zonal market design will no longer exist beginning December 1, 2010, when ERCOT is scheduled to implement a nodal market design, which provides greater efficiencies than a zonal design when resolving transmission congestion. Therefore, this contributor to ERCOT price spikes will no longer exist during operation of all four STP units, and will further reduce the net price spikes within ERCOT, even if the STP units were shut down.

64. These factors should minimize the impact of any additional price spikes due to the shutdown of the four STP units. However, even if it is conservatively assumed that such additional price spikes were to increase ERCOT prices by an additional 20% (doubling the percentage impact of the high price spikes in 2008) for the first year of the outage, there still would be no change to the conclusions of the SAMDA evaluation. As shown above, the 2008 average balancing price is $82.95 per MWh. The impact to consumers due to price spikes can be approximated using the total generation in 2009 and 20% of the $82.95 per MWh market price ($16.59). As shown in the 2009 ERCOT Hourly Load Data publication, the total generation in ERCOT in 2009 was 307,491,044 MWh. Therefore, the economic impact of the price spikes is $5,101,276,420 per year. Once the probability of the severe accident is accounted for with the CDF (1.56×10^{-7} per year), the resulting impact is $795.80 per year-squared. Accounting for a 40 year life of the plant and one year of additional price spikes due to the STP outages, the overall economic impact is $31,832. This calculation conservatively does not account for the discount rate.

65. When this $31,832 consumer impact due to price spikes is added to the total monetized impacts in Table 4 using the 7% discount rate ($50,947) and the consumer impacts due to market effects ($20,722), the resulting monetized impacts are $103,501. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $134,971. These impacts are still below the lowest cost of the SAMDAs ($158,000 in 2009 dollars). Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for price spikes does not affect the conclusion that there are no cost-effective SAMDAs.

E. <u>Loss of the Grid</u>

66. **[A. Pieniazek]** The Johnson Report (page 7) also states that the simultaneous loss of four STP units "could increase the likelihood of outages on the ERCOT grid which result in load shedding, or even uncontrolled blackouts." Although the Johnson Report does not quantify the change in costs due to these grid outages, it states that the grid outages will increase the economic costs.

67. As the Johnson Report states (page 7), the probability of an ERCOT grid outage following a shutdown of all four STP units "may not be high." ERCOT is responsible for running the grid reliably and avoiding the loss of load as per the ERCOT Protocols, the document approved by the PUCT which contains, among other things, the operating and reliability policies, rules, and standards of ERCOT. In addition, since the Northeast United States Blackout of 2003 (mentioned in the Johnson Report, page 7), ERCOT, as well as all other electricity regions in the United States, are under strict federally enforced reliability standards. These rigorous standards are monitored and enforced by the Texas Reliability Entity, which has the responsibility of ensuring the reliability of the bulk power system as per the requirements of NERC.

68. As explained in the Final Safety Analysis Report Section 8.2.2.3, the ERCOT grid is designed to simultaneously lose the two largest generators without a loss of the grid. In the event of a severe accident at one STP unit, the other units would be shut down in an orderly fashion, *i.e.*, all four units would not be taken off the grid simultaneously. Given the orderly shutdown, ERCOT would have time to adjust to the loss of the four units and to bring other generation sources online, invoke certain demand response programs, and to shed load if required. For example, Section 4.5 of the July 1, 2010 ERCOT Operating Guides (STP Attachment 10), a subset of the ERCOT Protocols, states that it may be necessary to reduce electrical demand due to a shortfall of supply, such as emergency outages of generators. These guides dictate actions to ensure that the ERCOT system frequency remains above 59.5 Hz, including actions such as using DC tie capability, deploying responsive reserves, and shedding loads. These load shed events are very infrequent, and have only occurred three times in the past eight years. For all of these reasons, it is extremely unlikely that the shutdown of the four STP units would result in a loss of the grid.

69. The low probability for loss of the grid also is attributable to many of the same factors that would minimize other market effects and price spikes due to shutting down the four STP units. For example, any potential for losses of the grid due to the lower generation in ERCOT would be minimized by adjustment of the ERCOT market to the loss of the STP units. This would occur as new units enter the market to replace the generation from the STP units. Additionally, ERCOT will have approximately 5,022 MW of mothballed capacity that could replace the lost generation. As discussed above, the generation from all four STP units also is less than the 12.5% reserve margin in ERCOT, which was calculated on the peak hour of the year. Therefore, in most, if not all hours of the year, ERCOT should have enough operating reserves to ensure adequate protection against the loss of load. These operating reserves naturally suppress grid outages.

70. Given all of the protective measures established by ERCOT, the Texas Reliability Entity, and NERC, as discussed above, it is extremely unlikely that a shutdown of all four STP units would result in a loss of the ERCOT grid. In fact, the protective measures have been successful in the past, and there has never been a loss of the entire ERCOT grid due to any event.

71. As discussed above, the CDF for the ABWR is 1.56×10^{-7} per year. Although it is difficult to quantify a probability for loss of the ERCOT grid due to shutdown of the four STP units, it is reasonable to assume that the probability is far less than 0.1. Thus, the probability of a severe accident at one of the ABWR units at the STP site, followed by a shutdown of the other three STP units, followed by a loss of the ERCOT grid, is far less than 10^{-8} per year. Such an occurrence is remote and speculative and does not need to be considered further.

72. Nonetheless, even if the impact of a grid outage is accounted for, there still is no cost-effective SAMDA. The cost of a grid outage can be approximated by assuming the outage lasted for 24 hours and calculating the "value of lost load" for the 24 hour black out period. The value of lost load can be approximated using the $3000 per MWh future price cap in ERCOT, which is the price determined by the PUCT as the point at which load is willing to curtail consumption. Using a very high summer load day in 2009 (August 4, 2009) where the load was 1,140,563 MWh, the total estimated value of lost load using the $3000 per MWh approximation is $3.42 Billion. As a point of comparison, the Johnson Report (page 7) states that the 2003 Northeast blackout is estimated to have caused $10 Billion in damage, but the Johnson Report states that it is an "extreme example."

73. The impact to consumers due to a grid outage can be approximated using the economic impact of the grid outage and the likelihood of the outage. Assuming the extreme example of $10 Billion in damages, once the probability of the severe accident is accounted for with the CDF (1.56×10^{-7} per year) and the 0.1 likelihood that a grid outage would occur following a severe accident, the resulting impact is $156 per year. Because the market would respond to the loss of the STP units, there would be essentially zero likelihood that the shutdown of the STP units would cause any loss of the grid after the first year of their outages. Accounting for a 40 year life of the plant, the overall economic impact is $6,240. This calculation conservatively does not account for the discount rate.

74. When this $6,240 impact due to a grid outage is added to the total monetized impacts in Table 4 using the 7% discount rate ($50,947), the consumer impacts due to market effects ($20,722), and the consumer impacts due to price spikes ($31,832), the resulting monetized impacts are $109,741. Using the 3% discount rate sensitivity analysis, the resulting monetized impacts are $141,211. These impacts are still below the lowest cost of the SAMDAs ($158,000 in 2009 dollars). Therefore, acceptance of the Intervenors' position that STPNOC's estimated replacement power costs should account for grid outages does not affect the conclusion that there are no cost-effective SAMDAs.

VI. CONCLUSION

75. **[All]** Based on the information provided in the ER, the ER revisions, and this Joint Affidavit, we conclude that the information previously provided by the Intervenors is not inconsistent in any material respect with the conclusions provided in ER Section 7.5S.5.

76. Additionally, the evaluation in this Joint Affidavit is very conservative. Some examples of this conservatism include:

- Assumption that the lowest-cost SAMDA will prevent all severe accidents.
- Performance of a sensitivity analysis for the replacement power cost estimates based on a 3% discount rate.
- Use of the 2008 ERCOT pricing data (highest prices since the ERCOT market was deregulated in 2002) as the basis for the replacement power cost estimates.
- Assumption that the outages at the STP site would cause additional price spikes, which in turn would increase the market price by 20% during the first year of outages.
- Assumption that a grid outage due to shutting down the STP units that is equivalent to the 2003 Northeast blackout occurs.
- Assumption of no discount rate when estimating the consumer impacts from market effects, price spikes, and grid outages.

This conservatism provides additional assurance that the conclusion that there are no cost-effective SAMDAs is consistent with the information provided by the Intervenors.

[All] I declare under penalty of perjury that the foregoing is true and correct.

Executed on September 14, 2010.

Executed in Accord with 10 C.F.R. § 2.304(d)

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Executed in Accord with 10 C.F.R. § 2.304(d)

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STP Attachment 1

JEFFREY L. ZIMMERLY
CORPORATE QUALITY ASSURANCE MANAGER / ENVIRONMENTAL ENGINEER
TETRA TECH NUS
AIKEN, SOUTH CAROLINA

EDUCATION: BS, Health Physics, Francis Marion University, 1996

EXPERIENCE SUMMARY:

Mr. Zimmerly has 10 total years of professional experience. Mr. Zimmerly serves as an Environmental Engineer supporting various government, utility, and industrial clients in the areas of environmental impact assessment, radiological transportation risk assessment, accident analysis, human health and ecological risk assessment, air quality modeling and compliance, occupational and environmental health physics, and radioactive waste management. Mr. Zimmerly serves as the Tetra Tech NUS (TtNUS) Corporate Quality Assurance Manager.

PROJECT EXPERIENCE:

Deputy Project Manager, Author, Third-Party Environmental Impact Statement for El Paso, Southern Natural Gas, FERC, March 2007 to August 2009. Mr. Zimmerly assisted in managing the preparation of the Environmental Analysis (EA) and related documents under the guidance of the FERC Project Manager for the South System Expansion III project. The project consists of 88 miles of various diameter pipe and modifications to compressor stations in Louisiana, Mississippi, Alabama, and Georgia. The EA analyzes impacts across four southern states traversing numerous sensitive resource locations. Preparation and publication of the EA involves review and support of cooperating state and federal agencies, preparing a Notice of Intent for the Federal Register, reviewing of Environmental Resource Reports, and preparing Data Requests in coordination with the FERC Staff. Mr. Zimmerly also authored and reviewed several sections of the drafts and final EA.

Health Physicist; Safety Light Corporation/EPA; January 2006 to present. Mr. Zimmerly serves as a Health Physicist supporting the preparation of a Remedial Investigation/Feasibility Study (RI/FI) of the Safety Light Corporation site in Bloomsburg, PA for the Environmental Protection Agency. The site, which has a history of several commercial processes and waste disposal activities involving radioactive material, was proposed for listing on the National Priority List. Mr. Zimmerly performed the human heath and ecological risk assessments and was a contributing author for the Remedial Investigation Reports and Feasibility Studies.

Environmental Engineer; Environmental Report in support of a Combined Operating License Application; Florida Power and Light; February 2008 to present. Mr. Zimmerly serves as an analyst for the preparation of an environmental report for the construction of two new nuclear reactors at the Turkey Point site in Florida. Mr. Zimmerly was a contributing author for the transportation of radioactive waste sections using the RADTRAN code, which calculates impacts of radioactive material transportation. Mr. Zimmerly was a contributing author and reviewer for the Severe Accident and Severe Accident Mitigation Alternatives sections and calculation package.

Radiological Transportation, Global Nuclear Energy Partnership (GNEP) EIS, DOE Office of Nuclear Energy; January 2007 – December 2008. Mr. Zimmerly served as the reviewer for the radioactive materials transportation analysis for the GNEP EIS.

Environmental Engineer; Environmental Report in support of a Combined Operating License Application and Early Site Permit; Exelon; December 2007 to present. Mr. Zimmerly serves as an analyst for the preparation of an environmental report for the construction of two new nuclear reactors at the Victoria Site in Victoria County TX. Mr. Zimmerly performed the impact analysis for heat dissipation to the atmosphere, as well as the analysis for an alternative heat dissipation to the atmosphere system. Mr. Zimmerly also analyzed the noise impacts from the construction and operation of the new units. Mr. Zimmerly was a contributing author for the transportation of radioactive waste sections. Mr. Zimmerly was a contributing author and reviewer for the Severe Accident and Severe Accident Mitigation Alternatives sections and calculation package.

Environmental Engineer; Environmental Report in support of a Combined Operating License Application; South Texas Nuclear Operating Company; December 2006 to present. Mr. Zimmerly serves as the QA Manager for the preparation of an environmental report for the construction of two new nuclear reactors at the South Texas Project (STP) site in Matagorda County TX. Mr. Zimmerly is responsible for the validation and documentation of statements of fact in the Environmental Report for the Combined Operating License (COL). Mr. Zimmerly performed the impact analysis for heat dissipation to the atmosphere using the Seasonal/Annual Cooling Tower Impact (SACTI) code. Mr. Zimmerly was a contributing author for the transportation of radioactive waste sections. Mr. Zimmerly was a contributing author and reviewer for the Severe Accident and Severe Accident Mitigation Alternatives sections and calculation package.

Health Physicist; Environmental Protection Agency; January 2004 to present. Mr. Zimmerly serves as an instructor for the EPA Emergency Response Training Program. He currently provides radiation safety overview training for environmental professionals and EMS first responders. He also provides technical support on radiological emergency response issues to Tetra Tech Superfund Technical and Response Team (START) program managers in eight EPA Regions.

Environmental Engineer; Environmental Report in support of a Combined Operating License Application; South Carolina Electric and Gas; January 2006 to present. Mr. Zimmerly serves as the QA Manager and as an analyst for the preparation of an environmental report for the construction of new nuclear reactors at an existing SCE&G site. As the QA Manager for the project, Mr. Zimmerly is responsible for the validation and documentation of statements of fact in the Environmental Report for the COL. As an analyst, Mr. Zimmerly performed the impact analysis for heat dissipation to the atmosphere, as well as the analysis for an alternative heat dissipation to the atmosphere system. Mr. Zimmerly was a contributing author and reviewer for the Severe Accident and Severe Accident Mitigation Alternatives sections and calculation package.

Environmental Engineer; Environmental Report in support of an Early Site Permit Application and Combined Operating License Application for Vogtle Electric Generating Plant; Southern Nuclear Company; January 2005 to July 2009. Mr. Zimmerly was an analyst for the environmental report in support of an early site permit (ESP) application prepared by Southern Nuclear Company (SNC) for submittal to the Nuclear Regulatory Commission. Mr. Zimmerly authored or co-authored several sections in the Environmental Report including impacts to members of the public, noise, and heat dissipation to the atmosphere. Mr. Zimmerly performed the new and significant analysis for the Severe Accident and Severe Accident Mitigation Alternatives section for the Combined Operating License Application (COLA).

Environmental Engineer; FERC Third-Party Environmental Impact Statement for Duke Energy Transmission Company, 2006 to 2007. Mr. Zimmerly assisted in the preparation of the Environmental Impact Statement and related documents for the Southeast Supply Header Project. The project involved review and supporting interagency documents provided by local, state and other federal agencies, review and supplementing Environmental Resource Reports supplied by the pipeline company, and authoring sections of the Environmental Impact Statement.

Environmental Engineer; Industrial Wastewater Closure Module for the High-Level Waste Tank 18 and Tank 19 System; Westinghouse Savannah River Company; Aiken, South Carolina; August 2000 to December 2004. Mr. Zimmerly assisted in the long-term performance modeling required in support of the individual Tank Module. He is the author of several chapters in the Tank Modules including Chapter 8, "Performance Evaluation," Appendix A, "Fate and Transport Modeling," and Appendix B, "Accounting for Tank Impacts Against Performance Objectives."

Environmental Safety & Health Representative; Demolition and Removal of Buildings and Facilities; U.S. Department of Energy-Savannah River; Westinghouse Savannah River Company; April 2003 to July 2003. Mr. Zimmerly provided support as the Environmental Safety & Health site representative for Demolition and Removal of excess buildings and facilities at U.S. Department of Energy – Savannah River under contract to Westinghouse Savannah River Company.

Environmental Engineer; Savannah River Site High-Level Waste Tank Closure Environmental Impact Statement; Westinghouse Savannah River Company; Aiken, South Carolina; August 2000 to May 2002. Contributing author of the Summary and Chapter 4, "Environmental Consequences." Assisted in the long-term performance modeling required in support of this EIS and individual Tank Modules. Participated in the effort to respond to public comments on the Draft EIS contained in Appendix D of the Final EIS.

Environmental Engineer; Final Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain; Jason Technology; Las Vegas NV; December 2000 to December 2001. Assisted the socioeconomic analyst with the manipulation, interpretation and presentation of the socioeconomic data and modeling results. Contributing author of the Data and Calculation Packages required for the EIS.

Environmental Engineer; Idaho High-Level Waste and Facilities Disposition Final Environmental Impact Statement; Idaho National Engineering and Environmental Laboratory, Idaho; October 2000 to September 2002. Performed the transportation risk analysis for the transportation of the vitrified waste and grout by truck and train. Prepared the text for this analysis in the Environmental Impact Statement.

Health Physicist; Confidential Client, California; November 2000. Investigated contaminants in the soil and prepared the text on the Nature and Extent of Radioactivity in Surface Soils.

Environmental Engineer; Human Health and Ecological Risk Assessment; MolyCorp Mountain Pass Mine; San Bernardino County, California; May 2000 to May 2005. Constructed the Human Health and Ecological Risk Assessment tables and calculations for the radiation exposure. Coordinated with other offices and their efforts to complete the risk assessment for the non-radioactive contaminants. Located and interpreted parameters required for this assessment and incorporated them into the risk assessment. Reviewing other related documents for alternatives in the risk assessment.

Environmental Engineer; Naval Facilities Engineering Command; Key West, Florida; June 2000 to Present. Provides support for various field efforts including ecological sample collection, performing field chemistry analysis, and media sampling for laboratory analysis of soil, sediment, surface water, and groundwater at operable units within various Navy facilities. Created reports to document and describe the sampling activities, present the sampling results, assess whether or not the goals of sampling were achieved, and provide conclusions and recommendations for any further actions.

Environmental Inspector; Federal Energy Regulatory Commission; September 2002 to Present. Provides support as an Environmental Inspector for the Federal Energy Regulatory Commission (FERC), conducting inspections ensuring environmental compliance during linear construction of natural gas pipeline projects nationwide. The inspections are performed to ensure that interstate pipeline construction adheres to the National Environmental Policy Act (NEPA) and typically an environmental assessment or environmental impact statement is required for the projects. Evaluates the pipeline companies during various stages of construction and restoration to assess their compliance with FERC regulations, and then documents and relays observations and recommendations directly to the FERC project managers.

Health Physicist; Argonne National Laboratory; Argonne, IL; May 2001 to May 2002. Conducted the independent verification of the code used to derive residual radioactive material guidelines for contaminated buildings

Nuclear Engineer/Health Physicist; Various Commercial Nuclear Utility Clients; May 2000 to present. Performing analyses and calculations to support the environmental reports for nuclear power plant license extension to NRC. License extension work includes the analysis of alternatives to the relicensing, electric shock analysis, and meteorology and air quality. Nuclear power plant sites include Susquehanna, Oyster Creek, Robinson, Summer, Brunswick, Pilgrim, Point Beach, Davis-Besse, Millstone, Dresden, Quad Cities, Wolf Creek, Kewaunee, Palo Verde, Three Mile Island, Vogtle, Crystal River, Duane Arnold, Salem, Hope Creek, South Texas Project, and Calloway.

CHRONOLOGICAL WORK HISTORY:

Environmental Engineer; Tetra Tech NUS, Inc.; Aiken, South Carolina; May 2000 to Present.

Intern; Westinghouse Savannah River Company; Aiken, South Carolina; May 1998 to August 1998.
Served as an intern with the Westinghouse Savannah River Company. His duties were to research the possibility for simultaneous determination of alpha, beta, and gamma radiation using a heterogeneous scintillating flow cell detection system that utilizes pulse shape discrimination.

Intern; Carolina Power and Light; North and South Carolina; 1995 to 1996.
Served as an intern with the Carolina Power and Light Company at the Brunswick Plant in Southport, North Carolina. His duties were to support the Health Physics group in creation of databases for hazardous chemicals, and data management and trend tracking. He also supported the programs group in preparation for and during a refueling outage.
Mr. Zimmerly served as an intern with the Carolina Power and Light Company at the Robinson Project in Hartsville, South Carolina. His duties were to support the Health Physics group in areas including dosimetry, respiratory protection, radioactive waste management, shipping, shift work, job coverage, training, and outage activities.

PROFESSIONAL AFFILIATIONS:

Health Physics Society
American Nuclear Society

STP Attachment 2

Adrian Pieniazek, P.E.
1005 Congress, Suite 1000
Austin, TX 78701
adrian.pieniazek@nrgenergy.com

Career Experience

NRG Texas LLC, Austin, TX

Director – Market Policy, April 2002 to present

- Market policy liaison to the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT). Develop and coordinate market policy and regulatory compliance matters pertaining to NRG Texas, with a specific emphasis on wholesale electricity market design and operations.
- Standing member of numerous ERCOT committees and task forces working to design, support and promote competitive electric markets.
- Served two years as President of the Texas Competitive Power Advocates, a trade association representing power generators, wholesale power marketers and retail electric providers conducting business in the Texas electric market.
- Served as NRG Texas' representative on all market participant groups that have redesigned the current wholesale market from its current zonal configuration to a nodal design based on the directives in the Final Order of PUCT Docket # 31540.

Reliant Energy Inc., Houston, Texas

Director – Asset Management, November 2000 to March 2002

- Directed a team of 60 employees responsible for all energy management and fuel procurement functions for Reliant Energy's 14,000 megawatt power generation portfolio in Texas.
- Responsible for the oversight and control of the Asset Management Division's annual budget, power and natural gas trading activities, fuel procurement functions, contract administration, and financial settlement functions for all ERCOT wholesale power and ancillary service transactions.
- Responsible for the direction and implementation of all transition activities resulting from the deregulation of the electric industry in ERCOT. Transition activities included, but were not limited to: 1) modifying all processes, procedures and systems related to scheduling, dispatching, procuring and financially settling energy and fuel supply transactions in the ERCOT wholesale market; 2) negotiating and implementing an amended and restated Joint Operation Agreement with City Public Service of San Antonio; and 3) implementing a new agreement to handle the scheduling and financial settlement of industrial facilities qualifying under the Public Utility Regulatory Policy Act.

CPS Energy, San Antonio, Texas

Director – Generation Planning, January 1996 to October 2000

- Directed all strategic planning functions for the CPS Energy power generation division.
- Responsible for contractual compliance, procedural enhancement and monthly financial settlement of the multi-year, multi-million dollar Joint Operation Agreement between City Public Service and Reliant Energy.
- Developed and implemented the generation division's annual business plan.

Lead Maintenance Engineer, Sommers/Deely Power Plant, September 1993 to December 1995

- Responsible for all maintenance activities at a 1,600 megawatt coal and gas-fired power plant complex.
- Directed 100 maintenance employees and managed all preventive, predictive and outage maintenance activities.

Senior Engineer - Technical Services, September 1991 to August 1993

- Supervised the engineering staff, performance testing group and the environmental and chemical laboratories.

Lead Instrumentation and Control Engineer, August 1989 to August 1991

- Responsible for instrumentation and control maintenance activities at all CPS Energy power plants.

TXU, Inc., Dallas, Texas

Superintendent – Technical Services, Graham Power Plant, January 1988 to August 1989

- Managed the engineering staff, instrumentation/control technicians, and the environmental and chemical laboratories at an 800-megawatt gas-fired steam electric station.

Performance Testing Engineer and Project Engineer, January 1983 to December 1987

- Performed American Society of Mechanical Engineer certified performance tests on all TXU fossil-fired facilities. Formulated work scope and budgetary estimates, developed project schedule and directed the implementation of various plant projects.

Education and Certifications

Masters of Business Administration, 1994, Our Lady of the Lake University, San Antonio, Texas
Bachelor of Science, Mechanical Engineering, 1982, Texas A&M University, College Station, Texas
Registered Professional Engineer, Texas - License 62544

STP Attachment 3

GE Nuclear Energy

December 21, 1994

MFN No. 162-94
Docket No. 52-001

Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: R. W., Borchardt, Director
Standardization Project Directorate

Subject: **NEPA/SAMDA Submittal for the ABWR**

Reference:
1. Letter, J.F. Quirk to R.W. Borchardt, same title, August 26, 1993, MFN No. 137-93
2. Letter, J.F. Quirk to R.W Borchardt, same title, November 18, 1994, MFN No. 148-94

The attached Technical Support Document (TSD) for the ABWR supersedes the TSD transmitted August 26, 1993 (Reference 1) and November 18, 1994 (Reference 2). On December 15, 1994, GE discussed the staff's comments on Reference 2. This updated version of the TSD incorporates staff comments.

The conclusions regarding radiological risk from severe accidents in plants of ABWR design remain unchanged and GE believes that this TSD provides a sufficient basis for the NRC to issue proposed amendments to 10CFR Part 52 which concludes:

1) for the ABWR design, all reasonable steps have been taken to reduce the occurrence of a severe accident involving substantial damage to the core and to mitigate the consequences of such an accident should one occur;

2) no cost-effective SAMDAs to the ABWR design have been identified to prevent or mitigate the consequences of a severe accident involving substantial damage to the core; and,

3) no further evaluation of severe accidents for the ABWR design, including SAMDAs to the design, is required in any environmental report, environmental assessment, environmental impact statement or other environmental analysis prepared in connection with issuance of a combined license for a nuclear power plant referencing a certified ABWR design.

2222 See Attached distribution

If you have any questions on the attached TSD, please call Peter D. Knecht at (408) 925-6215.

Sincerely,

Joseph F. Quirk
Project Manager
ABWR Certification
MC-782 (408) 925-6219

Att.

cc:	S.A. Hucik	(GE)	N.D. Fletcher	(DOE)
	T.H. Boyce	(NRC)	D.J. McGoff	(DOE)
	D.M. Crutchfield	(NRC)	F.A. Ross	(DOE)
	F.J. Miraglia, Jr.	(NRC)		
	A.C. Thadani	(NRC)		

25A5680

TECHNICAL SUPPORT DOCUMENT FOR THE ABWR

General Electric Company
San Jose, California
December 1994

Table 4
Cost Estimates of SAMDAs Evaluated for the ABWR Under NEPA

Potential Improvement	Cost Basis	Estimated Minimum Cost
1a. Severe Accident EPGs/AMGs	Plant specific procedure preparation beyond generic work by Owners' Group.	$ 600,000
1b. Computer Aided Instrumentation	Software modifications and interface hardw re. Credit for averted onsite cost included.	$ 599,600
1c. Improved Maintenance Procedures/Manuals	Procedure preparation. Credit for averted onsite cost included.	$ 299,000
2a. Passive High Pressure System	System hardware and installation ($1,200,000), Building modification ($550,000). Credit for averted onsite cost included.	$ 1,744,000
2b. Improved Depressurization	Logic, pneumatic supplies, piping and qualification. Credit for averted onsite cost included.	$ 598,600
2c. Suppression Pool Jockey Pump	System hardware and electrical connections. Credit for averted onsite cost included.	$ 120,000
2d. Safety Related Condensate Storage Tank	Structural analysis and material. Credit for averted onsite cost included.	$ 1,000,000
3a. Larger Volume Containment (Double Free Volume)	Double current volume at $1200/ft³. Analysis not included.	$ 8,000,000
3b. Increased Containment Pressure Capability (Sufficient pressure to withstand severe accidents)	Similar to Larger Volume Containment, but denser rebar and labor required. Assumed 50% higher cost	$ 12,000,000
3c. Improved Vacuum Breakers (Redundant valves in each line)	Eight lines at $10,000 per line	$ 100,000

Table 4 (Continued)

Potential Improvement	Cost Basis	Estimated Minimum Cost
3d. Improved Bottom Head Penetration Design	205 drives at $1,000/drive and $500,000 of analysis	$ 750,000
4a. Larger Volume Suppression Pool (Double effective liquid volume)	Assumed to be the same as Larger Volume Containment	$ 8,000,000
5a. Low Flow Filtered Vent	Hardware and Testing program	$ 3,000,000
7a. Drywell Head Flooding (Firewater crosstie to drywell head area)	Minor valve and piping modification with instrumentation	$ 100,000
8a. Additional Service Water Pump	System hardware, power supplies and support systems. Credit for averted onsite cost included.	$ 5,999,000
9a. Steam Driven Turbine Generator	System hardware, cabling and structural changes. Credit for averted onsite cost included.	$ 5,994,300
9b. Alternate Pump Power Source	400 kW generator at $300/kW. Credit for averted onsite cost included.	$ 1,194,000
10a. Dedicated DC Power Supply	5000 ft^2 building structure addition at $500/$ft^2$ and cabling	$ 3,000,000
11a. ATWS Sized Vent	Instrumentation and cabling in addition to training	$ 300,000
13a. Reactor Building Sprays (Firewater crosstie for reactor building sprays)	Minor valve and piping modification with instrumentation.	$ 100,000
14a. Flooded Rubble Bed	1250 ft^2 of material at $1000/lb	$ 18,750,000

The offsite costs for other items such as relocation of local residents, elimination of land use and decontamination of contaminated land were not considered. Reductions in the risk of incurring onsite costs including economic losses, replacement power costs and direct accident costs are considered in this evaluation as credits against in the cost of the modification.

Based on the PRA results (Section A.2), 82% of the offsite risk results from very low probability events which have high consequence. The maximum justifiable cost of a modification was determined to be $269. Therefore, based on this methodology, no modifications are justifiable. However, a variety of modifications were reviewed to establish the relative attractiveness of potential changes.

A.1.3 Methodology

The overall approach was to estimate the benefit of modifications in terms of dollar cost per total person-rem averted. Underestimated costs and overestimated benefits were assessed in order to favor modifications. Because of the uncertainties in the methodology and the desire to address severe accidents with sensible modifications, this basis is judged to be acceptable for purposes of this study.

A.1.3.1 Selection of Modifications

Potential modifications were identified from a variety of previous industry and NRC sponsored studies of preventative and mitigative features which address severe accidents. Based on this composite list of modifications considered on previous designs, potential modifications were selected for further review based on being

(1) applicable to the ABWR design, and

(2) not included in the reference PRA.

Additional detail on the selection of modifications is provided in Section A.3.

A.1.3.2 Costs Basis

Rough order of magnitude costs were assigned for each modification based on the costs of systems and system improvements determined by GE. These costs represent the estimated incremental costs that would be incurred in a new plant rather than costs that would apply on a backfit basis. Section A.5 defines the cost estimates for each of the modifications.

Even for a new plant such as the ABWR, relatively large costs (several million dollars) can be expected for some modifications if they involve modifications of the building structures or arrangement. This is because the cost of labor and material is often a function of the building area required. For other modifications which involve minor hardware addition, the cost is often dominated by the need for procedure and training additions which can amount to hundreds of thousands of dollars.

The costs estimates were intentionally biased on the low side, but all known or reasonably expected costs were accounted for in order that a reasonable assessment of the minimum cost would be obtained. Actual plant costs are expected to be higher than indicated in this evaluation. All costs are referenced to 1991 U.S. dollars. For modifications which reduce the core damage frequency, the costs of modifications (Section A.5) were further reduced by an amount proportional to the reduction present worth of the risk of averted onsite costs. Onsite costs include replacement power costs, direct accident costs (including onsite cleanup) and the economic loss of the facility. Evaluation of this credit included the following considerations:

(1) Accidents were assumed to occur at any time during the 60 year life of the plant. All onsite costs associated with the accident were evaluated as to their value at the time of the accident. The economic risk of such onsite costs was evaluated as a function of time based on the onsite costs and the core damage frequency determined by the PRA. The plant core damage frequency was considered to be constant over the life of the plant. The economic risks were then evaluated based on the present worth of the time dependent economic risks.

(2) Replacement power was based on a rate of $.013/kW-h differential as bar cost. The differential rate was assumed to be constant over the remaining life of the plant.

(3) The economic value of the facility at the time of the accident was based on a straight line depreciated value. The initial invested cost was taken at $1.4 Billion based on DOE cost guidelines.

(4) Accident costs for onsite cleanup and facility were evaluated based on escalated costs to the time of the accident. Reference accident costs to the facility were assumed to be $2 Billion.

(5) Th economic evaluations were based on a discount rate of 8% and escalation factor of 3%.

A.1.3.3 Benefit Basis

The cumulative risk of accidents occurring during the life of the plant was used as a basis for estimating the maximum benefit that could be derived from modifications. A particular modification's benefit was based on its effect on the frequency of events or associated offsite dose summarized in Tables A-1 and Table A-2. Dominant contributing failure probabilities were identified based on the PRA. Changes in these probabilities were estimated to evaluate the benefit of modifications. This basis is consistent with the approach taken in previous NRC evaluations. The cumulative offsite risk was evaluated over a 60 year plant life with no escalation in the evaluation criteria of $1,000/person-rem.

Section A.4 summarizes each concept and estimated benefit for each individual potential modification. For each modification the cost per person-rem averted was evaluated to obtain the results of the individual evaluations. These conclusions are provided in Section A.7.

STP Attachment 4

NUREG/BR-0184

United States
Nuclear Regulatory Commission

Regulatory Analysis Technical Evaluation Handbook

Final Report

Office of Nuclear Regulatory Research

January 1997

1 Introduction

The past two decades have seen an increasing recognition that governmental actions need to account for their societal and economic impacts. As early as 1969, the National Environmental Policy Act required an assessment of environmental impacts of major federal actions including descriptions of alternatives and any unavoidable environmental insults. In December 1977, the U.S. Nuclear Regulatory Commission (NRC) established value-impact analysis guidelines (SECY-77-388A) to aid its decision-making. Executive Order 12291 was issued in February 1981 (46 FR 13193) requiring that executive agencies prepare regulatory impact analyses for all major rules and directing that regulatory actions be based on adequate information regarding the need for and consequences of proposed actions. Although the order was not binding on the NRC, the Commission decided to meet its spirit to enhance the effectiveness of NRC regulatory actions. Accordingly, in January 1983, the NRC issued *Regulatory Analysis Guidelines* (NUREG/BR-0058) for performing regulatory analyses for a broad range of NRC regulatory actions (NRC 1983c). These guidelines established a framework for 1) analyzing the need for and consequences of alternative regulatory actions, 2) selecting a proposed alternative, and 3) documenting the analysis in an organized and understandable format. In December 1983, the NRC issued *A Handbook for Value-Impact Assessment* (NUREG/CR-3568 [Heaberlin et al. 1983]) (hereafter called the "1983 Handbook"). Its basic purpose was to set out systematic procedures for performing value-impact assessments. Revision 1 to NUREG/BR-0058 (NRC 1984b) was issued in May 1984 to include appropriate references to the 1983 Handbook.

In 1995, NRC's guidance on preparing regulatory analyses was updated in Revision 2 to NUREG/BR-0058 (NRC 1995a), hereafter referred to as the "NRC Guidelines" or simply the "Guidelines." Revision 2 was issued to reflect the NRC's experience implementing Revision 1 of the Guidelines; changes in NRC regulations since 1984, especially the backfit rule (10 CFR 50.109) and the Commission's 1986 Policy Statement on Safety Goals for the Operation of Nuclear Power Plants (NRC 1986); advances and refinements in regulatory analysis techniques; regulatory guidance in Executive Order 12866 (58 FR 51735; October 4, 1993); and procedural changes designed to enhance the NRC's regulatory effectiveness.

This revision to NUREG/CR-3568 (hereafter called the "Handbook") has been prepared to accomplish several objectives. First, the expanded guidance included in Revision 2 of the NRC Guidelines has been incorporated. Second, the scope of the Handbook has been increased to include the entire regulatory analysis process (not only value-impact analyses) and to address not only power reactor, but also non-reactor applications.[1] Third, NRC experience and improvements in data and methodology since the 1983 Handbook have been incorporated. Fourth, an attempt has been made to make the Handbook more "user friendly." Fifth, the Handbook incorporates guidance included in the document *Economic Analysis of Federal Regulations Under Executive Order 12866* (Regulatory Working Group 1996). This document, which superseded the Office of Management and Budget's (OMB's) "Regulatory Impact Analysis Guidance" (reference 6 in the NRC Guidelines), was prepared by a federal interagency regulatory working group.

This Handbook has been designed to assist the analyst in preparing effective regulatory analyses and to provide for consistency among them. The guidance provided is consistent with NRC policy and, if followed, will result in an acceptable document. It must be recognized, however, that all conceivable possibilities cannot be anticipated. Therefore, the Handbook guidance is intended to allow flexibility in interpretation for special circumstances. It must also be recognized that regulatory analysis methods continue to evolve, along with the applicable data. The NRC and other federal agencies (e.g., OMB, the U.S. Environmental Protection Agency [EPA], and the U.S. Department of Transportation [DOT]) continue to undertake research and development to improve the regulatory decision-making process.

1.1 Purpose

The purpose of this Handbook is to provide guidance to the regulatory analyst to promote preparation of high-quality regulatory decision-making documents and to implement the policies of the NRC Guidelines. In fulfilling this purpose, there are several objectives of the Handbook.

First, the Handbook expands upon policy concepts included in the NRC Guidelines. The steps in preparing regulatory analyses are translated into implementable methodologies for the analyst. An attempt is made to provide the rationale behind current NRC policy to assist the analyst in understanding what the decision-maker will likely need in the regulatory analysis. Second, the Handbook has been expanded to address the entire regulatory analysis process, i.e., all six steps (see Handbook Section 1.2.2) identified in the NRC Guidelines. The 1983 Handbook only addressed value-impact analysis, just one element of a regulatory analysis. Also, unlike the 1983 Handbook, this Handbook addresses not only power reactor but also non-reactor applications.

Third, the Handbook has been updated to incorporate changes in policy and advances in methodology that have occurred since the 1983 Handbook was issued. Considerable research has been conducted by the NRC and other agencies on various aspects of regulatory decision-making. Also, NRC staff experience has resulted in significant modifications to the regulatory analysis process. Advances resulting from the above have been appropriately incorporated in this Handbook.

Fourth, the Handbook has consolidated relevant information regarding regulatory analyses. As mentioned above, many activities have improved the ability to make better decisions. The resulting information has been used in the preparation of this Handbook. Where the information is not presented explicitly, references lead the analyst to the appropriate documents.

Fifth, the Handbook provides standardized methods of preparation and presentation of regulatory analyses, including backfit and Committee to Review Generic Requirements (CRGR) regulatory analyses. Consistent application of the methods provided here will result in more directly comparable analyses, thus aiding decision-makers in evaluating and comparing various regulatory actions.

The Handbook cites numerous references throughout, often extracting information from them directly. Where practical, the bases for extracted information have been summarized from the references. However, this does not imply that the analyst should use the information exclusively without consulting the references themselves. Where supplied data seem to contradict the analyst's "common sense," examination of the references may be crucial.

1.2 Regulatory Analysis Overview

The following sections provide an overview of a regulatory analysis. Section 1.2.1 discusses key terms and concepts in a regulatory analysis. Section 1.2.2 discusses the appropriate steps.

1.2.1 Key Terms and Concepts

Backfitting. Backfitting is defined at 10 CFR 50.109(a)(1) as "the modification of or addition to systems, structures, components, or design of a facility; or the design approval or manufacturing license for a facility; or the procedures or organization required to design, construct or operate a facility; any of which may result from a new or amended provision in the

Based on OMB's guidance in Circular A-94, Section 4.3.3 of the Guidelines requires that a 7% real (i.e., inflation-adjusted) discount rate be used for a best estimate. For sensitivity analysis, the Guidelines recommend a 3% discount rate. However, for certain regulatory actions involving a timeframe exceeding 100 years (e.g., decommissioning and waste disposal issues), Section 4.3.3 of the Guidelines stipulates the following:

> ...[T]he regulatory analysis should display results to the decision-maker in two ways. First, on a present worth basis using a 3 percent real rate, and second, by displaying the values and impacts at the time in which they are incurred with no present worth conversion. In this latter case, no calculation of the resulting net value... should be made.

"Qualitative" attributes do not lend themselves to quantification. To the degree to which the considerations associated with these attributes can be quantified, they should be; the quantification should be documented, preferably under one or more of the quantitative attributes. However, if the consideration does not lend itself to any level of quantification, then its treatment should take the form of a qualitative evaluation in which the analyst describes as clearly and concisely as possible the precise effect of the proposed action.

To estimate values for the accident-related attributes in a regulatory analysis, the analyst ideally can draw from detailed risk/reliability assessments or statistically-based analyses. Numerous sources exist for power reactor applications (e.g., see Section 5.6). To a lesser extent, Sections C.3-C.6 and C.10 provide similar data for non-reactor applications. Most regulatory analyses for power reactor facilities are based on detailed risk/reliability assessments or equivalent statistically based analyses.

However, the analyst will sometimes find limited factual data or information sufficiently applicable only for providing a quantitative perspective, possibly requiring extrapolation. These may often involve non-reactor licensees since detailed risk/reliability assessments and/or statistically-based analyses are less available than for power reactor licensees. Two examples illustrate this type of quantitative evaluation.

In 1992, the NRC performed a regulatory analysis for the adoption of a proposed rule (57 FR 56287; November 27, 1992) concerning air gaps to avert radiation exposure resulting from NRC-licensed users of industrial gauges. The NRC found insufficient data to determine the averted radiation exposure. To estimate the reduction in radiation exposure should the rule be adopted, the NRC proceeded as follows. The NRC assumed a source strength of one curie for a device with a large air gap, which produces 1.3 rem/hr at a distance of 20 inches from a Cs-137 source. Assuming half this dose rate would be produced, on average, in the air gap, and that a worker is within the air gap for four hours annually, the NRC estimated the worker would receive 2.6 rem/yr. The NRC estimated that adopting the proposed air-gap rule would be cost-effective if 347 person-rem/yr were saved. At the estimated average savings of 2.6 person-rem/yr for each gauge licensee, incidents involving at least 133 gauges would have to be eliminated. Given the roughly 3,000 gauges currently used by these licensees, the proposed rule would only have to reduce the incident rate by roughly 4%, a value the NRC believed to be easily achievable. As a result, the NRC staff recommended adoption of the air-gap rule.

In 1992, the NRC responded to a petition from General Electric (GE) and Westinghouse for a rulemaking to allow self-guarantee as an additional means for compliance with decommissioning regulations. An NRC contractor estimated the default risks of various types of financial assurance mechanisms, including the proposed self-guarantee. The contractor had to collect data on failure rates both of firms of different sizes and of banks, savings and loans, and other suppliers of financial assurance mechanisms. The contractor estimated a default risk of 0.13% annually for the GE-Westinghouse proposal, with a maximum default risk of only 0.055% annually for third-party guarantors, specifically a small savings and loan issuing a letter of credit. Based on these findings, the NRC initiated a proposed rulemaking which would allow self-guarantee for certain licensees. The final rule was issued December 29, 1993 (58 FR 68726).

Additional examples of this more limited type of quantitative approach to estimation can be found in Sections C.8 and C.9.

4. Calculate avoided property damage value per facility.

5. Sum avoided property damage over affected facilities.

In the 1983 Handbook, Heaberlin et al. made extensive use of NUREG/CR-2723 (Strip 1982) for offsite property cost estimation. Strip reported the present value of offsite health and property costs, onsite costs, and replacement power costs for accidents in release categories SST1 through SST3 for 91 U.S. power reactor sites. The offsite property costs were based on CRAC2 results, with 1970 population estimates and state-wide land use. The analyst may find the site-specific emphasis in Strip (1982) helpful in a more detailed value-impact analysis.

For a major effort beyond the standard analysis, it is recommended that the estimates be derived from information more site-specific than that used by Strip (1982). For power reactors, the MACCS code with the most recent data available should be used. This degree of effort would be relatively costly to conduct, both in terms of computer costs and data collection and interpretation costs. However, it would provide the highest degree of reliability.

Burke et al. (1984) examined the offsite economic consequences of severe LWR accidents, developing costs models for the following:

- population evacuation and temporary sheltering, including food, lodging, and transportation
- emergency phase relocation, including food, housing, transportation, and income losses
- intermediate phase relocation, beginning immediately after the emergency phase
- long-term protective actions, including decontamination of land and property and land area interdiction
- health effects, including the two basic approaches (human capital and willingness-to-pay).

Tawil et al. (1991) compared three computer models for estimating offsite property damage from power reactor accidents. Two of the models are the CRAC2 and MACCS codes; the third is the computer code DECON (Tawil et al. 1985). Three accident severity categories—SST1-SST3—are considered for the six Pasquill atmospheric stability categories (A-F). Offsite property damage is calculated for each pairing at cleanup levels from 10 through 200 rems. A study is also performed comparing the effect of modeling offsite damage to radii of 50 and 500 miles. It indicates that the choice of radius is significant only for the SST1 accident category, the differences being quite pronounced.

The FORECAST computer code for regulatory effects cost analysis (Lopez and Sciacca 1996) allows input for the offsite property attribute.

5.7.6 Onsite Property

Section 4.3.1 of the NRC Guidelines states that onsite property damage cost savings (i.e., averted onsite costs) need to be included in the value-impact analysis. In the net-value formulation it is a positive attribute.

Estimating the effect of the proposed action on onsite property involves three steps:

1. Estimate reduction in accident frequency (see Section 5.6).

2. Estimate onsite property damage.

3. Calculate reduction in risk to onsite property as

$$V_{OP} = N \Delta F U$$

where V_{OP} = monetary value of avoided onsite property damage ($)
N = number of affected facilities
ΔF = reduction in accident frequency (events/facility-year)
U = present value of property damage occurring with frequency F ($-year).

Reduction in onsite property damage costs (i.e., costs savings) is algebraically positive; increase (i.e., cost accruals) is negative (viewed as negative cost savings).

For the standard analysis, it is convenient to treat onsite property costs under three categories: 1) cleanup and decontamination, 2) long-term replacement power, and 3) repair and refurbishment. Each of these categories is considered below for power reactors with the focus on large-scale core-melt accidents. Additional categories of costs have been considered by Mubayi et al. (1995) and Burke et al. (1984) as outlined in Section 5.7.6.4, but they were either found to be speculative or contributed small fractions to the costs identified below.

5.7.6.1 Cleanup and Decontamination

Cleanup and decontamination of a nuclear facility, especially a power reactor, following a medium or severe accident can be extremely expensive. For example, Mubayi et al. (1995) report that the total cleanup and decontamination of TMI-2 cost roughly $750 million (in 1981 dollars). Murphy and Holter (1982) estimated cleanup costs for a reference PWR and BWR for the following three accident scenarios:

- Scenario 1 - a small LOCA in which ECCS functions as intended. Some fuel cladding ruptures, but no fuel melts. The containment building is moderately contaminated, but there is minimal physical damage.

- Scenario 2 - a small LOCA in which ECCS is delayed. Half of the fuel cladding ruptures, and some fuel melts. The containment building is extensively contaminated, but there is minimal physical damage.

- Scenario 3 - a major LOCA in which ECCS is delayed. All fuel cladding ruptures, and there is significant fuel melting and core damaged. The containment building is extensively contaminated and physically damaged. The auxiliary building undergoes some contamination.

In 1981 dollars, Murphy and Holter estimated the following cleanup costs:

Scenario	PWR	BWR
1	$1.05E+8	$1.28E+8
2	$2.24E+8	$2.28E+8
3	$4.04E+8	$4.21E+8

Mubayi et al. (1995) consider the TMI-2 accident to lie between Scenarios 2 and 3, lying closer to Scenario 3 in terms of the contamination and damage to the core. Murphy and Holter's costs were somewhat less than those actually realized at TMI. Mubayi et al. (1995) attribute the difference to three factors:

1. The start of the TMI cleanup was delayed by 2.5 years due to regulatory and financial requirements. Murphy and Holter assumed no additional delays between the accident and start of the cleanup. Mubayi et al. (1995) consider this somewhat unrealistic.

2. Decontamination at TMI required facilities not included in Murphy and Holter's reference plants (e.g., a hot chemistry laboratory, containment recovery service building, and comment center/temporary personnel access facility).

3. TMI required additional decontamination of the containment building after the reactor was defueled. Murphy and Holter excluded this in their analysis.

When these three factors are considered, the results from Murphy and Holter become reasonably consistent with the actual TMI cleanup costs ($7.50E+8 in 1981 dollars).

Burke et al. (1984) produced a very rough estimate of $1.7 billion (in 1982 dollars) for the cleanup and decontamination costs following a severe power reactor accident. An uncertainty range of approximately 50% was assigned, bringing the lower bound reasonably in line with the actual TMI cleanup cost. A study by Konzek and Smith (1990) updated the cleanup costs associated with Murphy and Holter's Scenario 3. Costs ranging from $1.22E+9 to $1.44E+9 (in undiscounted 1989 dollars) were estimated, based on real escalation rates of 4% to 8% during the cleanup period. A base cost of $1.03E+9 was estimated assuming no real escalation during the cleanup period.

After converting the costs to undiscounted 1993 dollars, the cost reported by Mubayi et al. (1995) for TMI is $1.2E+9, the base estimate from Konzek and Smith (1990) is $1.2E+9, and the estimate from Burke et al. (1984), which doubled the cost of TMI, is $2.5E+9. Based on these references, the total onsite cost estimates given in Section 5.7.6.4 are based on $1.5E+9 (undiscounted) for cleanup and decontamination (C_{CD} in the equations that follow). For sensitivity analysis, lower and upper bounds of $1.0E+9 and $2.0E+9 are recommended for evaluating severe accident effects.

Assuming the $1.5E+9 estimate is spread evenly over a 10-year period for cleanup (i.e., constant annual cost of C_{CD}/m = $1.5E+8 in the equation below, with C_{CD} = $1.5E+9 and m = 10 years), and applying a 7% real discount rate, the cost translates into a net present value of $1.1E+9 for a single event. This quantity is derived from the following equation (see Section B.2.3):

$$PV_{CD} = \left[C_{CD} / mr\right] \left[1 - \exp(-rm)\right]$$

where PV_{CD} = net present value of cleanup and decontamination costs for single event ($)
C_{CD} = total undiscounted cost for single accident in constant year dollars ($)
m = years required to return site to pre-accident state
r = real discount rate (as fraction, not percent).

Before proceeding, this present value must be decreased by the cleanup and decontamination costs associated with normal reactor end-of-life. The Yankee Atomic Electric Co. (NRC 1995c), Sacramento Municipal Utility District (NRC 1994), and Portland General Electric Co. (1995) provided the following estimates to the NRC for decommissioning their Yankee Rowe, Rancho Seco, and Trojan nuclear power plants, respectively: $3.41E+8 (1991 dollars), $2.80E+8 (1991 dollars), and $4.15E+8 (1993 dollars). These suggest a value of approximately $0.4E+9 (1993 dollars) for "normal" cleanup and decommissioning. The analyst can also consult Bierschbach (1995) for estimating PWR decommissioning costs and Bierschbach (1996) for estimating BWR decommissioning costs.

When spread evenly over the same 10-year period at a 7% real discount rate, this translates into a net present value of $0.3E+9. However, since this value would "normally" be applied at reactor end-of-life (i.e., 24 years later, using the estimate from Table B.1), the net present value (at the same 7% real discount rate) is reduced to $0.06E+9. Since this amounts to only 5% of the net present value for cleanup and decontamination following a severe accident ($1.1E+9), it can be generally ignored.

The total onsite cost estimates shown in Section 5.7.6.4 integrate this net present value over the average number of remaining service years (24 years) using the following equation:

$$U_{CD} = \left[PV_{CD} / r\right] \left[1 - \exp(-rt_f)\right]$$

where U_{CD} = net present value of cleanup and decontamination over life of facility ($-year)
t_f = years remaining until end of facility life.

The integrated cost is $1.3E+10 over the life of a power reactor. This cost must be multiplied by the accident frequency (F, expressed in events per facility-year), and the number of reactors, to determine the expected value of cleanup and decontamination costs. To determine averted costs, the reduction in accident frequency ΔF is applied as outlined in Section 5.7.6.

For comparison, these costs can also be estimated for less severe accidents as defined by Murphy and Holter's Scenarios 1 and 2. The estimates shown in the following table were obtained by using $1.1E+9 (1993 dollars) as a base value for Scenario-3 PV_{CD} costs, and applying the same relative fractions as shown in Murphy and Holter's (1982) results for Scenario-1 and 2 costs. The results from Murphy and Holter were not used directly because of the factors cited by Mubayi et al. (1995) in comparisons of those estimates with actual cleanup and decontamination costs at TMI.

Scenario	PV_{CD}	U_{CD}
1	$3.1E+8	$3.7E+9
2	$6.0E+8	$7.1E+9
3	$1.1E+9	$1.3E+10

The issue of license renewal has only moderate implications for the integrated cost estimates (U_{CD}). With longer operating lifetimes, the reactors are at risk for more years, and the costs would be expected to increase accordingly. However, because the additional costs are discounted to present worth terms, the effect is not substantial. For example, an additional life extension of 20 years would only increase the value of U_{CD} for a Scenario-3 accident 15% from $1.3E+10 to $1.5E+10.

5.7.6.2 Long-Term Replacement Power

Replaced power for short-term reactor outages is discussed in Section 5.7.7.1. Following a severe power reactor accident (replacement power need be considered only for electrical generating facilities), replacement power costs must be considered for the remaining reactor lifetime.[12]

Argonne National Laboratory (ANL) has developed estimates for long-term replacement power costs based on simulations of production costs and capacity expansion for representative pools of utility systems (VanKuiken et al. 1992). VanKuiken et al. examined replacement energy and capacity costs, including purchased energy and capacity charges required to provide the same level of system reliability as available prior to the loss of a power reactor (VanKuiken et al. 1993). In the event of a permanent shutdown, it was assumed that a reactor would be replaced by one or more alternative generating units, after an appropriate delay for planning and construction.

Capacity expansion and production cost simulations were performed for six representative power reactors over 40-year study periods. The results were used to estimate replacement power costs for each of 112 reactors which, at the time of the study, were expected to be in operation by 1996. Cost estimates for each reactor reflect the remaining lifetimes, reactor sizes, and ranges in short-term replacement energy costs (as encountered in each utility). Averages were determined by summing the individual reactor costs and dividing by the number of reactors evaluated. Characteristics for the "generic" reactor cited in Section 5.7.6.4 reflect an average unit size of 910-MWe and average life remaining of 24 years for reactors currently operating and planned.

Simulation results were first used to estimate the present value costs of single accidents occurring in each year of remaining facility lifetimes (quantity PV_{RP} used in the discussions that follow). Each of these net present values represents a summation of annual replacement power costs incurred from the year of the assumed accident to the final year of service. For example, the average net present value for an event occurring in 1993 is \$1.1E+9. For 1994, the cost is \$1.0E+9, and for 1995, the cost is \$0.9E+9. The decline in costs with each successive year reflects present value considerations and the fact that there are fewer remaining service years requiring replacement power.

The following equation can be used to approximate the average value of PV_{RP} for alternative discount rates.

$$PV_{RP} = \left[\$1.2E + 8 / r\right] \left[1 - \exp(-rt_f)\right]^2$$

where PV_{RP} = net present value of replacement power for a single event (\$).

The \$1.2E+8 value used in the above equation has no intrinsic meaning. It is treated in the equation similar to an equivalent annual cost, but it is actually a substitute for a string of non-constant replacement power costs that occur over the lifetime of the generic reactor after an event that takes place in 1993. The equation is only presented here for examining the effects of alternate discount rates and remaining reactor lifetimes.

The above equation for PV_{RP} was developed for discount factors in the range of 5%-10%. Unlike the equations for PV_{CD} and U_{CD}, the equation for PV_{RP} diverges from modeled results at lower discount rates. At a discount rate of 3% the recommended value for PV_{RP} is \$1.4E+9, as compared with the equation estimate of \$1.1E+9. For discount rates between 1% and 5% the analyst is urged to make linear interpolations using \$1.6E+9 at 1% and \$1.2E+9 at 5%. At higher discount rates the equation for PV_{RP} provides recommended estimates of \$1.2E+9 at 5% and \$1.0E+9 at 10%.

The results that are applied in Section 5.7.6.4 sum the single-event costs over all years of reactor service. While these summations were calculated directly from simulation results, ANL found that the outcomes could be closely approximated with the equation that follows. The squared term in this equation serves as a proxy for the fact that costs for events in future years decline due to the reduced number of remaining service years for which replacement power is required:

$$U_{RP} = \left[PV_{RP} / r\right] \left[1 - \exp(-rt_f)\right]^2$$

where U_{RP} = net present value of replacement power over life of facility (\$-year).

Replacement power costs for the generic unit are estimated to be approximately \$10 billion over the life of the facility. An uncertainty range for this average is estimated at approximately 20%. However, the range of estimates for specific power reactors varies directly with unit size, remaining life, and replacement energy costs. For example, costs were estimated to be \$7.5 billion for the 1040-MWe Zion-2 reactor, assuming 16 years of remaining operating life. Zion-2 is in a power pool with approximately average replacement energy costs. In contrast, costs for Big Rock Point were \$120 million due to its smaller size (67-MWe), shorter remaining life (8 years assumed), and average replacement energy costs. At the upper limit were costs of $24 billion for the 1090-MWe Nine Mile Point 2 unit, assuming 34 years of service remaining. Nine Mile Point 2 is in a power pool with above average replacement energy costs.

As noted for PV_{RP}, the equation for U_{RP} was developed for discount rates ranging from 5%-10%. For lower discount rates, linear interpolations for U_{RP} are recommended between $1.9E+10 at 1% and $1.2E+10 at 5%. The equation for U_{RP} yields the recommended values of $1.2E+10 at 5% and $0.8E+10 at 10%, based on PV_{RP} values described previously.

As discussed in Section 5.7.6.4, these summed costs must be multiplied by the accident frequency (expressed in events per facility-year) to determine the expected value of replacement power costs for a typical reactor. To determine the value of reductions in the accident frequency due to regulatory actions, the total integrated costs must be multiplied by the reduction in accident frequency ΔF and the number of reactors affected (N).

The issue of license renewal has a much more significant impact on replacement power costs than on cleanup and decontamination costs. Extending the operating life by an additional 20 years would increase the net present value of a single event (PV_{RP}) by about 38%, and would increase the present value of costs integrated over the reactor life (U_{RP}) by about 90% (VanKuiken et al. 1992). Thus, a license renewal period of 20 years would mean the generic reactor would have a remaining life of 44 years, PV_{RP} would be estimated to be $1.5E+9, and U_{RP} would be approximately $1.9E+10 (1993 dollars).

For less severe accidents such as characterized by Scenario-1 events, the analyst is referred to Section 5.7.7.1 which addresses short-term replacement energy costs. Replacement capacity costs, which contribute to severe accident costs, are not incurred for more temporary reactor shutdowns.

5.7.6.3 Repair and Refurbishment

In the event of recoverable accidents (i.e., for Scenario 1, but not Scenarios 2 or 3), the licensee will incur costs to repair/replace damaged components before a facility can be returned to operation (these costs are not included in the total onsite cost estimates for severe accidents as addressed in Section 5.7.6.4). Burke et al. (1984) have estimated typical costs for equipment repair on the order of $1,000/hr of outage duration, based on data from outages of varying durations at reactors. They suggest an upper bound of roughly 20% of the long-term replacement power costs for a single event. Mubayi et al. (1995) observe that the $1,000/hr figure corresponds closely to the repair costs following the Browns Ferry fire and also to the TMI-1 steam generator retubing outage costs.

5.7.6.4 Total Onsite Property Damage Costs

Based on the information included in Sections 5.7.6.1 and 5.7.6.2, ANL has estimated the total cost due to onsite property damage following a severe reactor accident for the Zion-2 reactor and a "generic" 910-MWe reactor assumed to have a remaining life of 24 years. Total costs are assumed to consist of cleanup and decontamination costs and replacement power costs (repair and refurbishment costs are not included for severe accidents). The total costs described below correspond to the "risk-based" costs as defined by Mubayi et al. (1995):

> "...risk-based cost, the discounted net present value of the risk over the remaining life of the plant, which is proportional to the accident frequency [F]..."

The risk-based costs (quantities U, U_{CD}, and U_{RP} in the equations that follow) must be interpreted carefully to avoid misunderstandings. They do not represent the expected onsite property damage due to a single accident. Rather, they are the present value of a stream of potential losses extending over the remaining lifetime of the facility. Thus, they reflect the expected loss due to a single accident (given by quantities PV_{CD} and PV_{RP}); the possibility that such an accident could occur, with some small probability, at any time over the remaining facility life; and the effects of discounting those potential future losses to the present value. When the quantity U is multiplied by the annual accident frequency, the result is the expected loss over the facility life, discounted to the present value.

The estimates for total risk-based costs attributed to regulatory actions that occur in 1993, expressed in 1993 dollars assuming a 7% real annual discount rate, are as follows:

Variable	Cost Component	Zion-2	"Generic" Reactor
U_{RP}	Replacement Power	\$0.7E+10 x F	\$1.0E+10 x F
U_{CD}	Cleanup & Decontamination	\$1.0E+10 x F	\$1.3E+10 x F
U	Total	\$1.7E+10 x F	\$2.3E+10 x F

Alternate values of U may be approximated for different discount rates, years of operation remaining, and estimates for C_{CD} and PV_{RP}. However, for changes in discount rate or final year of operation, the analyst is cautioned to revise the estimates for PV_{RP} using the equation described in Section 5.7.6.2 prior to re-estimating U from the equation that follows. Also, for discount rates lower than 5%, PV_{RP} and U_{RP} should be estimated from interpolation guidelines presented in Section 5.7.6.2 rather than from the equations. The relationship that defines total lifetime costs is

$$
\begin{aligned}
U &= U_{CD} + U_{RP} \\
&= \left[C_{CD} / mr^2\right] \left[1 - \exp(-rt_f)\right] \left[1 - \exp(-rm)\right] + \left[PV_{RP} / r\right] \left[1 - \exp(-rt_f)\right]^2
\end{aligned}
$$

where U = total net present value of onsite property damage (\$-year).

The procedure outlined in Section 5.7.6 may be used to evaluate averted onsite property damage using these estimates. For illustration, assume that the reduction in severe accident frequency (ΔF) is 1.0E-6 and the number of reactors affected (N) is 111. The total averted onsite damage costs would be

$$V_{OP} = N\Delta FU = (111)(1.0E-6)(\$2.3E+10) = \$2.6E+6$$

The value of this reduction in accident frequency is \$2.6 million (net present value in 1993 dollars).

The \$2.3E+10 value used above is an appropriate generic estimate for regulatory requirements that become effective in 1993 and that affect severe accident probabilities in that year. For regulatory actions that affect accident frequencies in future years, the cost estimates must be adjusted to recognize that the number of reactor-years at risk and the number of service years requiring replacement power are reduced. Table 5.7 shows how these factors affect cost estimates for the 10-year period of 1993-2002. The results are expressed as net present values discounted to the year that the rulemaking is assumed to take effect.

To illustrate the use of these estimates, assume a reduction in accident frequency of 1.0E-6 begins in 1998 and affects all 111 of the remaining reactors. The revised estimate for U would be \$1.9E+10 and the total averted onsite damage costs for this reduction in frequency would be

$$V_{OP} = (111)(1.0E-6)(\$1.9E+10) = \$2.1E+6 \text{ (1993 dollars)}$$

Table 5.7 Onsite property damage cost estimates (U) for future years (1993 dollars discounted to year of implementation)

	Cleanup and Decontamination (U_{CD})	Replacement Power (U_{RP})	Total (U)
1993	\$1.3E+10	\$1.0E+10	\$2.3E+10
1994	\$1.2E+10	\$9.6E+9	\$2.2E+10
1995	\$1.2E+10	\$9.1E+9	\$2.1E+10
1996	\$1.2E+10	\$8.6E+9	\$2.1E+10
1997	\$1.1E+10	\$8.1E+9	\$1.9E+10
1998	\$1.1E+10	\$7.6E+9	\$1.9E+10
1999	\$1.1E+10	\$7.1E+9	\$1.8E+10
2000	\$1.1E+10	\$6.6E+9	\$1.8E+10
2001	\$1.0E+10	\$6.2E+9	\$1.6E+10
2002	\$1.0E+10	\$5.7E+9	\$1.6E+10

This would indicate that the reduction in accident frequency valued at \$2.6 million beginning in 1993 would be valued at \$2.1 million if introduced in 1998 (1993 dollars adjusted to 1998).

The following linear equation provides approximate cost estimates for implementation later than 10 years in the future. The result represents net present value (1993 dollars) discounted to the year of implementation. The analyst must adjust the 1993 dollars for general inflation if costs are to be expressed in alternate reference-year dollars. (See Section 5.8 for information on adjusting dollar years.)

$$U = \$2.3E + 10 - (\$6.7E + 8)\left(t_i - 1993\right)$$

where t_i = year of reduction in accident frequency.

Thus, for regulatory actions that would affect accident probabilities for 86 reactors remaining in service in 2010, the revised estimate for U would be

$$\begin{aligned} U &= \$2.3E + 10 - (\$6.7E + 8)(2010 - 1993) \\ &= \$1.2E + 10 \text{ (1993 dollars adjusted to 2010)} \end{aligned}$$

The total averted onsite damages costs for a reduction in accident frequency of 1.0E-6 would be

$$\begin{aligned} V_{OP} &= (86)(1.0E - 6)(\$1.2E + 10) \\ &= \$1.0E + 6 \text{ (1993 dollars adjusted to 2010)} \end{aligned}$$

This example also illustrates that the number of reactors at risk and the average remaining years of reactor service change in the evaluation of future regulatory initiatives. Because of the distribution of license expiration dates, the average remaining reactor life does not decrease on a one-to-one basis with each successive year in the future.

For 20-year license renewal considerations, the estimates for U discussed above should be increased by approximately 50%. In 1993, U_{CD} would be estimated at \$1.5E+10 (versus \$1.3E+10 for 40-year license), and U_{RP} would be estimated to be \$1.9E+10 (versus \$1.0E+10 for 40-year license). This yields a total of \$3.4E+10 (1993 dollars) as compared with \$2.3E+10 for the 40-year license assumption.

Costs for onsite property damage from non-reactor accidents have been assembled in Section C.2.5. However, most are given as combined offsite and onsite damage costs.

For a major effort beyond the standard analysis, there are two general ways to achieve a greater level of detail: 1) the analysis can be conducted for individual facilities or groups of similar facilities, using site-specific information; 2) the analysis can provide cost information in much greater detail. With regard to the first approach, the most relevant site-specific information includes the cost of long-term replacement power and the value of the facility and equipment at risk, taking into account the remaining useful life of the facility. The analyst is referred to VanKuiken et al. (1992) for further detail on average shutdown costs for different categories of reactors (e.g., by region, reactor supplier, architect engineer, etc.), and guidance for scaling costs for different unit sizes and remaining lifetimes.

With regard to providing greater detail on the cost information, the major cost elements (in addition to replacement power) are likely to include decontamination and other cleanup costs and repair or replacement of plant and equipment that is physically damaged. Other costs relate to transporting and disposing of contaminated materials and equipment, and startup costs. Costs for monitoring the site for radiation and fixing contamination at the site will likely be insignificant relative to the other costs. The analyst is referred to Murphy and Holter (1982), and the follow-up study by Konzek and Smith (1990), for detailed cost estimates to decontaminate a nuclear power reactor following a postulated accident.

Burke et al. (1984) examined the onsite economic consequences of severe LWR accidents, developing cost models for the following:

- replacement power, drawing information mainly from Buehring and Peerenboom (1982) (which has been updated by VanKuiken et al. [1992])
- plant decontamination, including both medium and large consequence events
- plant repair, spanning small to large consequence events
- early decommissioning for medium and large consequence events
- worker health effects and medical care, primarily for medium and large consequence events
- electric utility "business" (i.e., costs resulting from changed risk perceptions in financial markets and the need to replace the income once produced by the operating plant after a power plant is permanently shutdown)
- nuclear power "industry" (i.e., costs resulting from elimination or slowed growth in the U.S. nuclear power industry due to altered policy decisions and risk perceptions following a severe accident)
- onsite litigation (i.e., "legal fees for the time and effort of those individuals involved in the litigation process").

The first three categories of costs have been covered in Sections 5.7.6.1-5.7.6.3. The other categories are covered elsewhere in this Handbook or are considered to be either speculative or small in magnitude relative to replacement power, cleanup and decontamination, and repair costs.

The FORECAST computer code for regulatory effects cost analysis (Lopez and Sciacca 1996) allows input for the onsite property attribute.

5.7.7 Industry Implementation

This section provides procedures for computing estimates of the industry's incremental costs to implement the proposed action. Estimating incremental costs during the operational phase that follows the implementation phase is discussed in Section 5.7.8. Incremental implementation costs measure the additional costs to industry imposed by the regulation; they are costs that would not have been incurred in the absence of that regulation. Reduction in the net cost (i.e., cost savings) is algebraically positive; increase (i.e., cost accrual) is negative (viewed as negative cost savings). Both NRC and Agreement State licensees should be addressed, as appropriate.

In general, there are three steps that the analyst should follow in order to estimate industry implementation costs:

Step 1 - Estimate the amount and types of plant equipment, materials, and/or labor that will be affected by the proposed action.

Step 2 - Estimate the costs associated with implementation.

Step 3 - If appropriate, discount the implementation costs, then sum (see Section B.2).

In preparing an estimate of industry implementation costs, the analyst should also carefully consider all cost categories that may be affected as a result of implementing the action. Example categories include

- land and land-use rights
- structures
- hydraulic, pneumatic, and electrical equipment
- radioactive waste disposal
- health physics
- monitoring equipment
- personnel construction facilities, equipment, and services
- engineering services
- recordkeeping
- procedural changes

- license modifications
- staff training/retraining
- administration
- facility shutdown and restart
- replacement power (power reactors only)
- reactor fuel and fuel services (power reactors only)
- items for averting illness or injury (e.g., bottled water or job safety equipment).

Note that transfer payments (see Section 4.3) should not be included.

For the standard analysis, the analyst should use consolidated information to estimate the cost to industry for implementing the action. Sciacca (1992) is a prime source of such information, providing not only cost estimates, but also labor hours, cost rates, and adjustment factors, mainly for reactor facilities. Appropriate references are cited by Sciacca. The FORECAST computer code for regulatory effects cost analysis (Lopez and Sciacca 1996) incorporates much of the information assembled by Sciacca (1992) into a computer database for the analyst's use in estimating industry implementation as well as other costs.

Step 1 - Estimate the amounts and types of plant equipment, materials, and/or labor that will be affected by the proposed action, including not only physical equipment and craft labor, but professional staff labor for design, engineering, quality assurance, and licensing associated with the action. If the action requires work in a radiation zone, the analyst should account for the extra labor required by radiation exposure limits and low worker efficiency due to awkward radiation protection gear and tight quarters (see discussion of labor productivity in Section 5.7.4.1).

When performing a sensitivity analysis, but not for the best estimate, the analyst should include contingencies, such as the most recent greenfield construction project contingency allowances supplied by Robert Snow Means Co., Inc. (1995). They suggest adding contingency allowances of 15% at the conceptual stage, 10% at the schematic stage, and 2% at the preliminary working drawing stage. The FORECAST computer code (Lopez and Sciacca 1996) contains an option to include an allowance for uncertainty and cost variations at the summary cost level. The Electric Power Research Institute (EPRI 1986) offers guidelines for use in estimating the costs for "new and existing power generating technologies." EPRI suggests applying two separate contingency factors, one for "projects" to cover costs resulting from more detailed design, and one for "process" to cover costs associated with uncertainties of implementing a commercial-scale new technology.

Step 2 - Estimate the costs associated with implementation, both direct and indirect. Direct costs include materials, equipment, and labor used for the construction and initial operation of the facility during the implementation phase. Indirect costs include required services. The analyst should identify any significant secondary costs that may arise. One-time component replacement costs and associated labor costs should be accounted for here. For additional information on cost categories, especially for reactor facilities, see Schulte et al. (1978) and United Engineers and Constructors, Inc. (1979; 1988a, b).

Step 3 - If appropriate, discount the costs, then sum. If costs occur at some future time, they should be discounted to yield present values (see Section B.2). If all costs occur in the first year or if present value costs can be directly estimated, discounting is not required. Generally, implementation costs would occur shortly after adoption of the proposed action.

When performing value-impact analyses for non-reactor facilities, the analyst will encounter difficulty in finding consolidated information on industry implementation costs comparable to that for power reactors. Comprehensive data sources such as Sciacca (1992) and the references from which he drew his information are generally unavailable for non-reactor facilities. Some specific information for selected non-reactor facilities is in Sections C.7-C.10. The types of non-reactor facilities (see Section C.1) are quite diverse. Furthermore, within each type, the facility layouts typically lack the limited standardization of the reactor facilities. These combine to leave the analyst pretty much "on his own" in developing industry implementation costs for non-reactor facilities. The analyst should follow the general guidelines given in this Handbook section. Specific data may be best obtained through direct contact with knowledgeable sources for the facility concerned, possibly even the facility personnel themselves.

For a major effort beyond the standard analysis, the analyst should obtain very detailed information, in terms of the cost categories and the costs themselves. The analyst should seek guidance from NRC contractors or industry sources experienced in this area (AE firms, etc.). The incremental costs of the action should be defined at a finer level of detail. The analyst, should refer to the code of accounts in the Energy Economic Data Base (EEDB [United Engineers and Constructors, Inc. 1988b]) or Schulte et al. (1978) to prepare a detailed account of implementation costs.

5.7.7.1 Short-Term Replacement Power

For power reactors, the possibility that implementation of the proposed action may result in the need for short-term replacement power must be addressed. Section 4.3.2 of the Guidelines indicates that replacement power costs are to be incorporated into a regulatory analysis when appropriate. Unlike the long-term costs associated with severe power reactor accidents discussed in Section 5.7.6.2, the replacement power costs associated with industry implementation of a regulatory action would be short-term.

For a "typical" 910-MWe reactor operating at an average capacity factor of 60%-65%, VanKuiken et al. (1992) suggests $310,000/day (1993 dollars) as an average cost for short-term replacement power. The 60%-65% range in capacity factor is representative of annual averages, accounting for unplanned outage periods and planned outage periods for maintenance and refueling. However, if the timing of a short-term shutdown coincides with a time when a power reactor is expected to be fully operational, then a higher average cost per day is more appropriate. At a capacity factor of 100%, the average cost for the typical reactor is estimated to be $480,000/day (1993 dollars).

At a more detailed level, VanKuiken et al. (1992) project the seasonal replacement power costs for potential short-term shutdowns of 112 nuclear power plants over the five-year period from 1992 through 1996. These costs are estimated from probabilistic production-cost simulations of pooled utility-system operations. Average daily replacement power costs are presented by season for each of the 112 plants. The 20 U.S. power pools containing these plants are identified along with their following characteristics: total system capacity, annual peak load, annual energy demand, annual load factor, prices for fuels, and mix of generation by fuel type.

The sensitivity of replacement power costs to changes in oil and gas prices is quantified for each power pool. The effects of multiple plant shutdowns are addressed, with the replacement power costs quantified for each pool assuming all plants within the pool are shutdown.

The replacement power cost information compiled in an analogous but earlier study by VanKuiken et al. (1987) has subsequently been incorporated into two cost analysis computer codes. The Replacement Energy Cost Analysis Package (RECAP [VanKuiken et al. 1994]) determines the replacement energy costs associated with short-term shutdowns of nuclear power plants, and can be applied to determine average costs for general categories based on location, unit type (e.g., BWR), constructor, utility, and other differentiating criteria. Plant-specific costs are also available, and can be evaluated for user-specified outage durations and alternative capacity factor assumptions. FORECAST (Lopez and Sciacca 1996), a computer code for regulatory effects cost analysis, provides the user with the capability to estimate replacement power costs in current year dollars. Sciacca (1992) also provides a discussion and data for use in estimating replacement power costs based on this earlier study by VanKuiken et al. (1987).

Imposition of a new regulation often requires that a nuclear power plant be shutdown while the modification takes place. If the requirement is needed to meet adequate protection, the analyst can assume that the required downtime is independent of any scheduled downtime, thereby realizing full replacement power costs. However, the modification often is not needed to meet adequate protection, enabling it to be completed during already scheduled downtime. Only if the time needed to perform the modification exceeds that allotted for the scheduled downtime should any replacement power costs accrue, these being solely due to the excess time.

The most likely scenario permits the modification to be accommodated completely within already scheduled downtime, and this has frequently been the policy adopted by the NRC. As a result, no replacement power costs accrue. While this assumption holds for a modification performed in the absence of others required by new regulations, it tends to underestimate the cost of multiple modifications resulting from the cumulative effect of new NRC requirements. When multiple modifications are performed, as they often are, the originally scheduled downtime may be insufficient to accommodate all of them. Usually, this results from the limited number of available maintenance personnel and space restrictions for nearby component repair or service.

Historic data indicate roughly 15 days per year, or 17% and 25% of the annually scheduled downtime for PWRs and BWRs, respectively, can be attributed to the cumulative impact of new regulatory requirements. Assuming the contribution of each regulatory requirement to the incremental downtime equals the overall percentage increase, one can assign a prorated share to that requirement (i.e., 17% for PWRs, 25% for BWRs, or roughly 20% for LWRs in general). For example, if a regulatory requirement requires one-week of reactor shutdown time, 1.2 days (PWRs), 1.8 days (BWRs), or 1.4 days (LWRs) of additional downtime and, thus, replacement power costs would accrue.

5.7.7.2 Premature Facility Closing

Several nuclear power plants have been voluntarily shut down prior to the expiration of their operating licenses. Normally, a decommissioning cost of approximately \$0.3E+9 (1993 dollars) would be associated with an end-of-life shutdown (see Section 5.7.6.1). However, if a proposed regulatory requirement is expected to result in a premature shutdown, this cost is shifted to an earlier time with an associated net increase in its present value. For example, if a plant with an estimated t years of remaining life is prematurely closed, the net increase in present value, for a real discount rate of r, becomes (\$0.3E+9) $[1 - 1/(1+r)^t]$.

Thus, a plant closed 20 years early will incur an additional cost of \$0.2E+8 for a 7% real discount rate.

5.7.8 Industry Operation

This section provides procedures for estimating industry's incremental costs during the operating phase (i.e., after implementation) of the proposed action. The incremental costs measure the additional costs to industry imposed by the proposed action; they are costs that would not have been incurred in the absence of the action. Reduction in the net cost

STP Attachment 5

U.S. NUCLEAR REGULATORY COMMISSION

ENVIRONMENTAL STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

7.3 SEVERE ACCIDENT MITIGATION ALTERNATIVES

REVIEW RESPONSIBILITIES

Primary—Appendix B

Secondary—Appendix B

I. AREAS OF REVIEW

This environmental standard review plan (ESRP) directs the staff's evaluation of the severe accident mitigation alternatives (SAMAs), referred to as severe accident mitigation design alternatives (SAMDAs) in some references. The scope includes the identification and evaluation of design alternatives and procedural modifications that reduce the radiological risk from a severe accident by preventing substantial core damage (i.e., preventing a severe accident) or by limiting releases from containment in the event that substantial core damage occurs (i.e., mitigating the impacts of a severe accident). The intent is to identify additional cases that might warrant either additional features or other actions that would prevent or mitigate the consequences of serious accidents.

Review Interfaces

The reviewer for this ESRP should provide input to or obtain input from the reviewers for the following ESRP sources, as indicated:

- ESRP 7.2. Obtain information that characterizes the risk profile of the plant. This includes a list showing leading contributors to (1) core damage frequency (e.g., from dominant severe accident sequences or initiating events), (2) large release frequency (e.g., from containment failure mode or accident-progression bin), and (3) dose consequences with and without interdiction (e.g., from each release class and associated source term).

- 10 CFR 50.34(f)(1)(I). Obtain input from the responsible 10 CFR 50.34(f)(1)(I) reviewer to ensure consistency of the SAMA and the 10 CFR 50.34(f)(l)(I) reviews.

- Internal Plant Examination (IPE). Obtain input from the responsible reviewer for the IPE to ensure consistency of the SAMA analysis with the findings of the IPE.

- Internal Plant Examination of External Events (IPEEE). Obtain input from the responsible reviewer of the IPEEE to ensure consistency of the SAMA analysis with the results of the IPEEE.

- Safety Analysis Report (SAR), Chapter 19 Review. Obtain input from the responsible reviewer of Chapter 19 of the SAR to assure consistency of the SAMA analysis with the results of the SAR Chapter 19 review.

Data and Information Needs

The type of data and information needed will be affected by site- and station-station-specific factors, and the degree of detail should be modified according to the anticipated magnitude of the potential impacts. The following data or information should be obtained:

- a list of leading contributors to (1) core damage frequency (e.g., from dominant severe accident sequences or initiating events), (2) large release frequency (e.g., from containment failure mode or accident progression bin), and (3) dose consequences with and without interdiction (e.g., from each release class and associated source term) (from ESRP 7.1)

- the methodology, process, and rationale used by the applicant to identify, screen, and select design alternatives and procedural modifications (from the environmental report [ER])

- the estimated cost, risk reduction, and value impact ratios for the selected SAMAs and the assumptions used to make these estimates (from the ER)

- a description and list of any alternatives that have been or will be implemented to prevent or mitigate severe accidents or reduce the risk of a severe accident (from the ER).

II. ACCEPTANCE CRITERIA

Acceptance criteria for the analysis and evaluation of severe accident mitigation alternatives are based on the relevant requirements of the following:

- the U.S. Court of Appeals decision in Limerick Ecology Action v. NRC 869 F.2d 719 (3rd Cir. 1989) with respect to the requirement that the NRC include consideration of certain SAMAs in environmental impact reviews performed under Section 102(2)(c) of NEPA as part of operating-license applications

- 10 CFR 50.34(f)(1)(I) with respect to requirements for the applicant to perform a plant/site-specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems that are significant and practical and do not impact excessively on the plant

- 10 CFR 52.17 with respect to requirements in 10 CFR 50.34(f) for the applicant to perform a plant/site-specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems that are significant and practical and do not impact excessively on the plant

- 10 CFR 52.79 with respect to requirements to contain the technically relevant information required of applicants for an operating license in 10 CFR 50.34

Regulatory positions and specific criteria necessary to meet the regulations identified above are provided in the following:

- Interim Policy Statement, "Power Plants—Nuclear Power Plant Accident Considerations under NEPA" (1980) with respect to the early consideration of either additional features or other actions that would prevent or mitigate the consequences of serious accidents

- SECY-91-229 (NRC 1991a), which presents alternative courses of action and the staff's recommendations concerning the treatment of the SAMA issues to be considered under NEPA as they relate to the certification of standard plant designs, including evolutionary, passive, and advanced reactors

- NUREG/BR-0058, Rev. 2 (NRC 1997a), which states the policy for the preparation and the contents of regulatory analyses, including estimation of values and impacts for design alternatives and the "dollars per person-rem" conversion factors

- NUREG/BR-0184 (NRC 1997b) with respect to the value impact methodology

- NUREG/CR-6349 (Mubayi et al. 1995) with respect to dollars per person-rem conversion factor for offsite damage costs

- Generic Letter 88-20 (NRC 1988) with respect to the performance of an IPE at operating plants for severe-accident vulnerabilities

- Generic Letter 88-20, Supplement 3 (NRC 1990), with respect to accident prevention and mitigation features identified in the Containment Performance Improvement Program that may be valid for consideration in the review of SAMA

- Generic Letter 88-20, Supplement 4 (NRC 1991b), with respect to conducting an individual plant examination for externally initiated events.

In addition, the following acceptance criterion is used:

- Completeness and reasonableness, also with respect to the following: (1) the identification of SAMAs applicable to the plant or design under consideration, (2) the estimation of core damage frequency reduction and averted person-rem for each SAMA, (3) the estimation of cost for each SAMA, (4) the ranking of value-impact screening criteria to identify SAMAs for further consideration, and (5) the final disposition of promising SAMAs.

Technical Rationale

The technical rationale for evaluation of the applicant's severe accident mitigation alternatives is discussed in the following paragraphs:

An evaluation of SAMAs is required to be performed as part of the certification of new designs for nuclear power plants (as well as licensing custom plants) and for site approval applications. The purpose of SAMAs is to review and evaluate plant-design alternatives that could significantly reduce the radiological risk from a severe accident by preventing substantial core damage (i.e., preventing a severe accident) or by limiting releases from containment in the event that substantial core damage occurs (i.e., mitigating the impacts of a severe accident).

In 1980, the NRC published an interim policy statement (Interim Policy Statement, "Nuclear Power Plant Accident Considerations Under the National Environmental Policy Act of 1969" [NRC 1980]) that stated that it was the intent of the Commission for the staff to take steps to identify additional cases that might warrant early consideration of either additional features or other actions that would prevent or mitigate the consequences of serious accidents.

In 1985, the NRC published a policy statement ("Policy Statement on Severe Reactor Accidents Regarding Future Designs and Existing Plants," August 9, 1985 [NRC 1985a]). It concluded that existing plants posed no undue risk to public health and safety and no present basis for immediate action on a generic rulemaking or other regulatory changes for these plants because of severe accident risk. However, the policy statement indicated that "the Commission plans to formulate an approach for a systematic safety examination of existing plants to determine whether particular accident vulnerabilities are present and what cost-effective changes are desirable to ensure that there is no undue risk to public health and safety."

A 1989 court decision (*Limerick Ecology Action vs. NRC*, 869 F.2d 719 [3rd Cir. 1989] stated that the "Action of NRC in addressing severe accident mitigation design alternatives through policy statement, not rule making, did not satisfy NEPA, where policy statement did not represent requisite careful consideration of environmental consequences, excluded consideration of design alternatives without making any conclusions about effectiveness of any particular alternative, and issues were not generic in that impact of severe accident mitigation design alternatives on environment would differ with particular plant's design, construction and locations."

Currently, NRC considers the evaluation of SAMAs in the environmental impact review that is now performed as part of every application for a construction permit, an early site permit, an operating license, and a combined license. In addition, the Commission has endorsed staff consideration of SAMAs in conjunction with the design certification application. The purpose of this consideration is to ensure that plant design changes with the potential for improving severe accident performance are identified and evaluated.

III. REVIEW PROCEDURES

This procedure applies to the review of applications for construction permits, operating licenses, combined licenses, standard design certifications, and early site permits.

When evaluating SAMAs, the reviewer should do the following:

(1) Be familiar with analyses previously performed and with the potential process and design alternatives, if any, in previous studies, including the following:

- Limerick (NRC 1989)
- Watts Bar (NRC 1995)
- 10 CFR 50.34(f)(l)(I) reviews of the System 80+ (NRC 1997c)
- the Advanced Boiling Water Reactor (ABWR) (NRC 1997d)
- the GESSAR II (NRC 1985b)
- the Containment Improvement Program
- Generic Environmental Impact Statement for License Renewal (NRC 1996).

(2) Evaluate the applicant's methods for identifying the potential mitigation alternatives. If the applicant used an alternative methodology to a probabilistic risk assessment approach to assess potential SAMAs (e.g., a margins-based approach to evaluate external events initiated by fires or seismic activity), the staff evaluation should be appropriately modified. For example, the synergistic effects of mitigation alternatives that reduce risks for internally initiated events that also provide a benefit for mitigation of externally initiated events should be considered. Alternative benefit-cost approaches are appropriate when a margins method has been used to screen external events.

   (a) Determine if this set of potential design alternatives and procedural modifications represents a reasonable range of preventive and mitigative alternatives.

(b) Verify that the applicant's list of potential SAMAs includes a reasonable range of applicable SAMAs derived from consideration of previous analyses and based on insights from the Level 1 and Level 2 portions of the applicant's probabilistic risk assessment (PRA) or IPE/IPEEE.

(3) Evaluate the applicant's basis for estimating the degree to which various alternatives would reduce risk (expressed as a reduction in core damage frequency or in terms of person-rem averted). In performing its independent assessment, the staff may make bounding assumptions to determine the magnitude of the potential risk reduction for each SAMA.

(4) Evaluate whether the applicant's cost estimates for each SAMA are reasonable and compare the cost estimates with estimates developed elsewhere (e.g., using previous SAMA evaluations or using accepted cost-estimation tools).

(5) Evaluate the benefit-cost comparison to determine if it is consistent with the benefit-cost balance criteria and methodology given in NUREG/BR-0058, Rev. 2 (NRC 1997a), and further analyze any SAMAs that are within a decade of the NUREG/BR-0058, Rev. 2, or NUREG/CR-6349 (Mubayi et al. 1995) benefit-cost criteria to ensure that a sufficient margin is present to account for uncertainties in assumptions used to determine the cost and benefit estimates. The benefit-cost criterion in NUREG/BR-0058 is $200,000 per person-sievert averted ($2000 per person-rem averted) for health effects. In addition, a criterion of $300,000 per person-sievert averted ($3000 per person-rem averted) is given in NUREG/CR-6349 (Mubayi et al. 1995) for offsite damage and other related costs for severe accidents.

(6) Subject any SAMAs that remain following the screening given above to further probabilistic and deterministic considerations, including a qualitative assessment of the following:

- the impact of additional benefits that could accrue for the SAMA if it would be effective in reducing risk from certain external events, as well as internal events
- the effects of improvements already made at the plant
- any operational disadvantage associated with the potential SAMA.

IV. EVALUATION FINDINGS

The input to the environmental impact statement (EIS) should describe the applicant's analysis and detail the staff's review process. Any design mitigation or procedural modification should be described along with the estimated benefit-cost ratio. The risk reduction for the facility should be provided.

A concluding statement similar to the following should be made in the EIS:

> The staff concludes that the applicant completed a comprehensive, systematic effort to identify and evaluate the potential plant enhancements to mitigate the consequences of severe accidents. The

staff considered the robustness of this conclusion relative to critical assumptions in the analysis—specifically the impact of uncertainties in the risk and cost estimates and the use of alternative benefit-cost screening criteria. The staff concludes that the findings of the analysis would be unchanged even considering these factors. Therefore the staff concludes that the mitigation alternatives committed to by the applicant are appropriate and no further mitigation measures are warranted.

V. IMPLEMENTATION

The method described herein will be used by the staff in evaluating conformance with the Commission's regulations, except in those cases in which the applicant proposes an acceptable alternative for complying with specified portions of the regulations.

VI. REFERENCES

10 CFR 50.34, "Contents of application; technical information."

10 CFR 51.53, "Postconstruction environmental reports."

10 CFR 52.17, "Contents of application."

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U.S. Nuclear Regulatory Commission (NRC). 1991b. Generic Letter 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10 CFR 50.54(f)." June 28, 1991, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). April 1995. *Final Environmental Statement Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2*. NUREG-0498, Suppl. 1, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997a. *Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission. Final Report*. NUREG/BR-0058, Rev. 2, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997b. *Regulatory Analysis Technical Evaluation Handbook*. NUREG/BR-0184, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997c. *Final Environmental Assessment by the Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Relating to the Certification of the System 80+ Standard Nuclear Plant Design*. NUREG-1462, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997d. *Final Environmental Assessment by the Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Relating to the Certification of the U.S. Advanced Boiling Water Reactor Design*. NUREG-1503, Washington, D.C.

STP Attachment 6

2009 STATE OF THE MARKET REPORT
FOR THE
ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

July 2010

Executive Summary

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2009, and is submitted to the Public Utility Commission of Texas ("PUCT") and the Electric Reliability Council of Texas ("ERCOT") pursuant to the requirement in Section 39.1515(h) of the Public Utility Regulatory Act. It includes assessments of the incentives provided by the current market rules and procedures, and analyses of the conduct of market participants. This report also assesses the effectiveness of the scarcity pricing mechanism pursuant to the provisions of PUCT Substantive Rule 25.505(g). Key findings in the report include the following:

- ★ The average wholesale electricity price was $34.03 per MWh in 2009, which is 56 percent lower than the 2008 average price of $77.19 per MWh. This is the lowest annual average price experienced in the ERCOT wholesale market since 2002.

- ★ All-in wholesale electricity prices for the ERCOT market in 2009 were lower than in the organized wholesale electricity markets in California, New England, the New York ISO, and the PJM Interconnection.

- ★ Lower wholesale electricity prices provide benefits to consumers in the short-term. However, pricing outcomes in 2009 continued to inadequately reflect market conditions during times of operating reserve scarcity. During such shortage conditions when demand for energy and operating reserves cannot be met with available resources, prices should rise sharply to reflect the value of diminished reliability as reserves are used to meet energy needs. Although these shortage conditions occur in only a handful of hours each year, efficient shortage pricing is critical to the long-term success of the ERCOT energy-only market.

- ★ As a result of inadequate shortage pricing and the fact that the number of shortage intervals in 2009 were roughly one-half of that experienced in 2008, estimated net revenues in 2009 were substantially below the levels required to support market entry for natural gas combined-cycle and combustion turbine resources at all locations in the ERCOT region. Estimated net revenues for nuclear and coal resources were also insufficient to support new entry in 2009, although these results were more affected by the reduction in natural gas prices and associated reduction in wholesale energy prices than by pricing outcomes during shortage conditions.

★ Ancillary service costs generally track wholesale energy price movements, and therefore were significantly lower in 2009 than in recent years.

★ Load participation in the responsive reserve market declined in late 2008 and in 2009 relative to prior years, likely as a result of general economic conditions.

★ Interzonal price disparities were larger in 2008 and 2009 than in prior years, primarily as a result of increased wind capacity in the West Zone and inefficiencies that are inherent to the zonal market design.

★ The number of hours in which coal was the marginal (*i.e.*, price-setting) fuel in the ERCOT region was much higher in 2009 than in prior years. This increase can be attributed to (1) increased wind resource production; (2) a slight reduction in demand in 2009 due to the economic downturn; and (3) periods when natural gas prices were very low thereby making coal and natural gas combined-cycle resources competitive from an economic dispatch standpoint.

★ The ERCOT wholesale market performed competitively in 2009, with the competitive performance measures showing a trend of increasing competitiveness over the period 2005 through 2009.

In addition to these key findings, the report generally confirms prior findings that the current market rules and procedures are resulting in systemic inefficiencies. Our previous reports regarding ERCOT electricity markets have included a number of recommendations designed to improve the performance of the current ERCOT markets.[1] Some of these recommendations have

[1] "ERCOT State of the Market Report 2003", Potomac Economics, August 2004 ("2003 SOM Report"); "2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets", Potomac Economics, November 2004; "ERCOT State of the Market Report 2004", Potomac Economics, July 2005 ("2004 SOM Report"); "ERCOT

been implemented. Given the approaching implementation of the nodal market design in December 2010, no additional recommendations for the current market design are offered at this time. In particular, implementation of the nodal market will provide the following improvements:

- ★ The nodal market design will fundamentally improve ERCOT's ability to efficiently manage transmission congestion, which is one of the most important functions in electricity markets.
- ★ The wholesale market should function more efficiently under the nodal market design by providing better incentives to market participants, facilitating more efficient commitment and dispatch of generation, and improving ERCOT's operational control of the system. The congestion on all transmission paths and facilities will be managed through market-based mechanisms in the nodal market. In contrast, under the current zonal market design, transmission congestion is most frequently resolved through non-transparent, non-market-based procedures.
- ★ Under the nodal market, unit-specific dispatch will allow ERCOT to more fully utilize generating resources than the current market, which frequently exhibits price spikes even when generating capacity is not fully utilized.
- ★ The nodal market will allow ERCOT to increase the economic and reliable utilization of scarce transmission resources well beyond that attainable in the zonal market.
- ★ The nodal market will significantly improve the ability to efficiently and reliably integrate the ever-growing quantities of intermittent resources, such as wind and solar generating facilities.
- ★ The nodal market will produce price signals that better indicate where new generation is most needed (and where it is not) for managing congestion and maintaining reliability.

State of the Market Report 2005", Potomac Economics, July 2006 ("2005 SOM Report"); "ERCOT State of the Market Report 2006", Potomac Economics, August 2007 ("2006 SOM Report"), "ERCOT State of the Market Report 2007", Potomac Economics, August 2008 ("2007 SOM Report"); and "ERCOT State of the Market Report 2008", Potomac Economics, August 2009 ("2008 SOM Report").

In the long-term, these enhancements to overall market efficiency should translate into substantial savings for consumers.

B. Review of Market Outcomes

1. Balancing Energy Prices

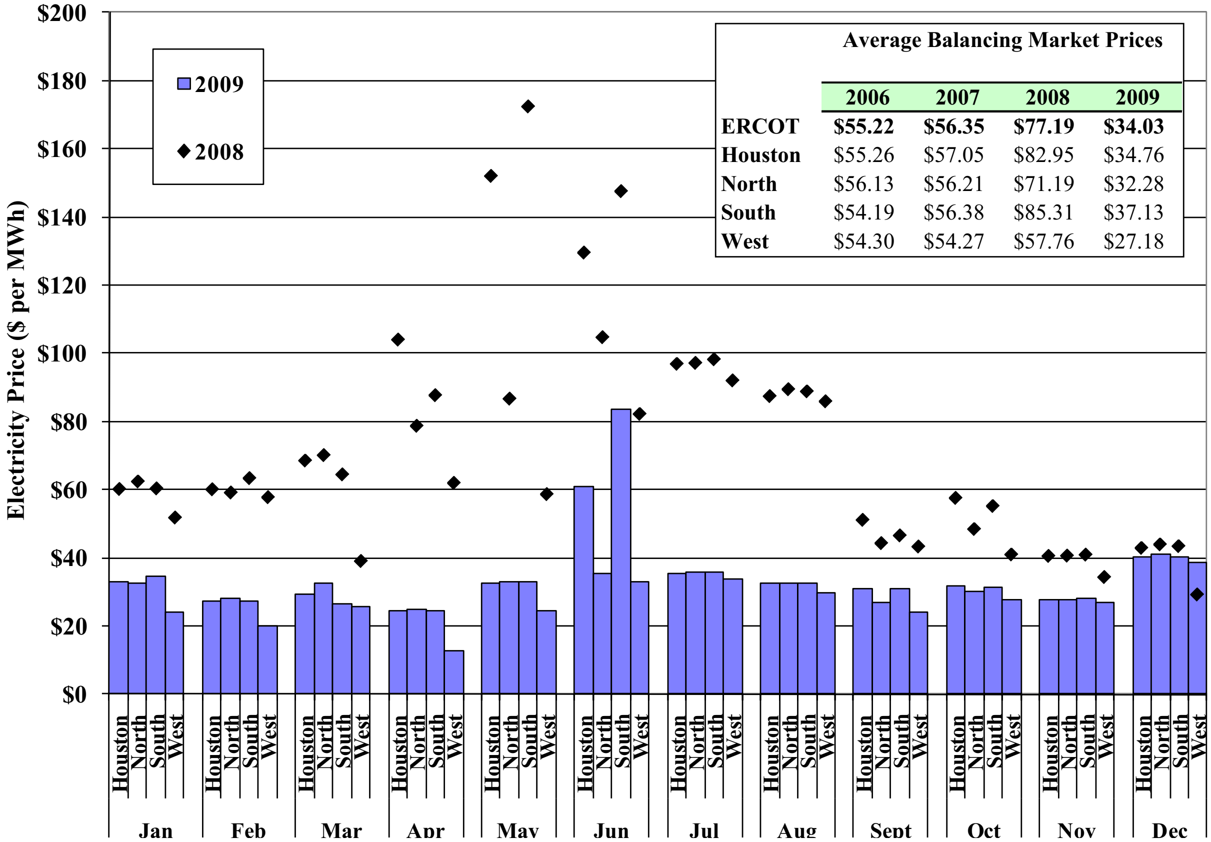
The balancing energy market allows participants to make real-time purchases and sales of energy to supplement their forward bilateral contracts. While on average only a relatively small portion of the electricity produced in ERCOT is cleared through the balancing energy market, its role is critical in the overall wholesale market. The balancing energy market governs real-time dispatch of generation by altering where energy is produced to: a) balance supply and demand; b) manage interzonal congestion, and c) displace higher-cost energy with lower-cost energy given the energy offers of the Qualify Scheduling Entities ("QSEs").

In addition, the balancing energy prices also provide a vital signal of the value of power for market participants entering into forward contracts. Although most power is purchased through forward contracts of varying duration, the spot prices emerging from the balancing energy market should directly affect forward contract prices.

As shown in the following figure, ERCOT average balancing energy market prices were 56 percent lower in 2009 than in 2008, with an ERCOT-wide load weighted average price of $34.03 per MWh in 2009 compared to $77.19 per MWh in 2008. April through August experienced the highest balancing energy market price reductions in 2009, averaging 66 percent lower than the prices in the same months in 2008. With the exception of the West Zone in December, the balancing energy prices in 2009 were lower in every month in all zones than in 2008.

The average natural gas price fell 56 percent in 2009, averaging $3.74 per MMBtu in 2009 compared to $8.50 per MMBtu in 2008. Natural gas prices reached a maximum monthly average of $12.37 per MMBtu in July 2008, and reached a minimum monthly average of $2.93 per MMBtu in September 2009. Hence, the changes in energy prices from 2008 to 2009 were largely a result of natural gas price movements.

Average Balancing Energy Market Prices



	2006	2007	2008	2009
ERCOT	**$55.22**	**$56.35**	**$77.19**	**$34.03**
Houston	$55.26	$57.05	$82.95	$34.76
North	$56.13	$56.21	$71.19	$32.28
South	$54.19	$56.38	$85.31	$37.13
West	$54.30	$54.27	$57.76	$27.18

The following figure shows the price duration curves for the ERCOT balancing energy market each year from 2006 to 2009. A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). The prices in this figure are hourly load-weighted average prices for the ERCOT balancing energy market.

Figure 5: Zonal Price Duration Curves

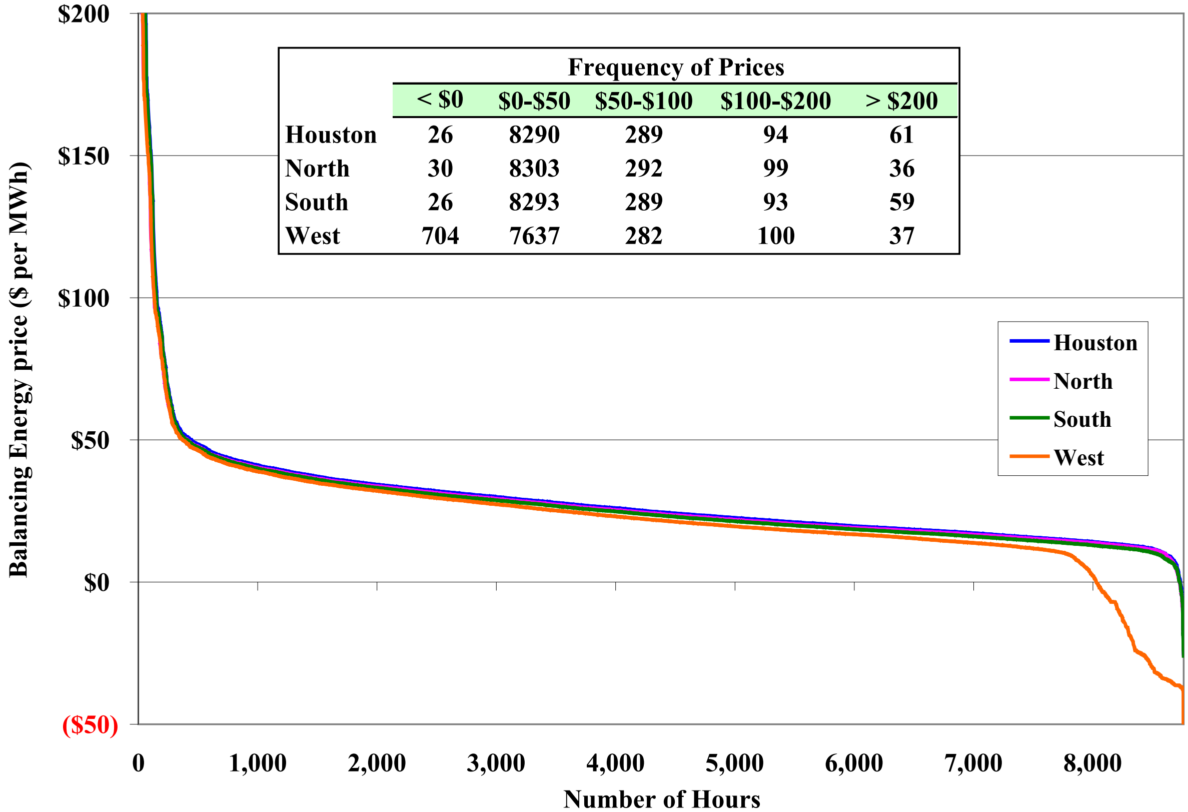
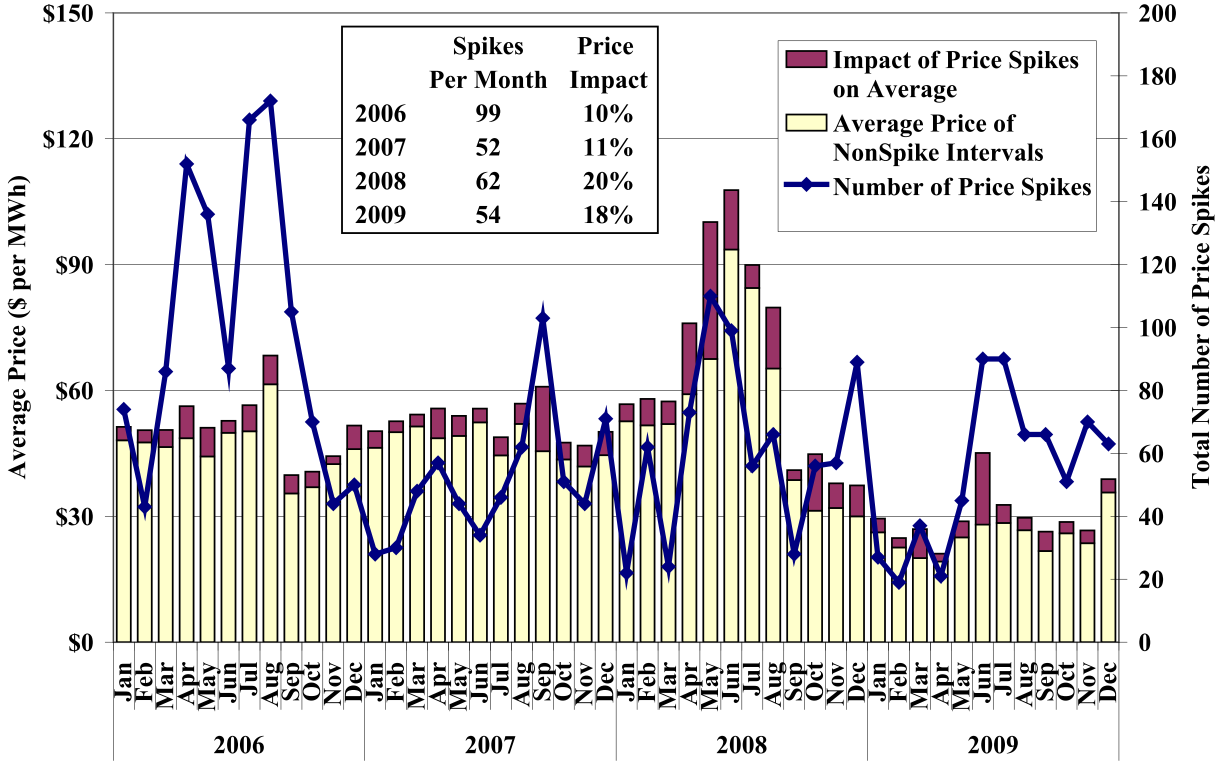


Figure 5 shows the hourly average price duration curve for each of the four ERCOT zones in 2009 and that the Houston, North and South Zones had similar prices over the majority of hours in 2009. The price duration curve for the West Zone is generally lower than all other zones, with over 700 hours when the average hourly price was less than zero. These zonal price differences are caused by zonal transmission congestion, as discussed in more detail in Section III.

Other market factors that affect balancing energy prices occur in a subset of intervals, such as the extreme demand conditions that occur during the summer or when there is significant transmission congestion. Figure 4 shows that there were differences in balancing energy market prices between 2006 and 2009 at the highest price levels. For example, 2008 experienced considerably more occasions when prices spiked to greater than $300 per MWh than previous years. To better observe the effect of the highest-priced hours, the following analysis focuses on the frequency of price spikes in the balancing energy market from 2006 to 2009. Figure 6 shows average prices and the number of price spikes in each month of 2006 to 2009. In this case, price spikes are defined as intervals where the load-weighted average Market Clearing Price of Energy ("MCPE") in ERCOT is greater than 18 MMbtu per MWh times the prevailing natural gas price (a level that should exceed the marginal costs of virtually all of the on-line generators in ERCOT).

Figure 6: Average Balancing Energy Prices and Number of Price Spikes



The number of price spike intervals was 62 per month during 2008. The number decreased in 2009 to 54 per month. The highest frequency of price spikes occurred in June and July during 2008, caused by significant transmission congestion that ERCOT was inefficiently attempting to resolve by using zonal congestion management techniques.[11] The high number of price spikes during June 2009 was also the result of zonal congestion management actions, although for reasons different than in 2008, as discussed in Section III. Other months with a higher frequency of price spikes in 2009 – particularly in the months after May 2009 – can be attributed to the more frequent deployment of off-line, quick start gas turbines in the balancing energy market as a result of the implementation of PRR 776 in May 2009, as discussed in Section II. Off-line, quick start gas turbines typically have a marginal cost that is greater than the 18 MMBtu per MWh threshold used in Figure 6.

[11] *See* 2008 ERCOT SOM Report, at 81-87.

To measure the impact of these price spikes on average price levels, the figure also shows the average prices with and without the price spike intervals. The top portions of the stacked bars show the impact of price spikes on monthly average price levels. The impact grows with the frequency of the price spikes, averaging $4.68, $5.30, $10.71 and $4.67 per MWh during 2006, 2007, 2008 and 2009, respectively. Even though price spikes account for a small portion of the total intervals, they have a significant impact on overall price levels.

Although fuel price fluctuations are the dominant factor driving electricity prices in the ERCOT wholesale market, fuel prices alone do not explain all of the price outcomes. Several other factors provided a meaningful contribution to price outcomes in 2009. These factors include (1) changes in peak demand and average energy consumption levels, as discussed in Section II; (2) changes in the frequency and magnitude of transmission congestion, as discussed in Section III; (3) the increased penetration of wind resources, as discussed in Sections II and III; (4) the effectiveness of the scarcity pricing mechanism, as discussed in Section II; and (5) the competitive performance of the wholesale market, as discussed in Section IV. Analyses in the next subsection adjust for natural gas price fluctuations to better highlight variations in electricity prices not related to fuel costs.

2. Balancing Energy Prices Adjusted for Fuel Price Changes

The pricing patterns shown in the prior subsection are driven to a large extent by changes in fuel prices, natural gas prices in particular. However, prices are influenced by a number of other factors as well. To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 7 and Figure 8 show balancing energy prices adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the balancing energy price is replaced by the marginal heat rate that would be implied if natural gas were always on the margin. The *Implied Marginal Heat Rate* equals the *Balancing Energy Price* divided by the *Natural Gas Price*.[12] The second chart shows the same duration curves for the five percent of hours in each year with the highest implied heat rate. Both figures show duration curves for the implied marginal heat rate for 2006 to 2009.

12 This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

STP Attachment 7

2008 STATE OF THE MARKET REPORT
FOR THE
ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

August 2009

EXECUTIVE SUMMARY

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2008. It includes assessments of the incentives provided by the current market rules and procedures, and analyses of the conduct of market participants. This report also assesses the effectiveness of the scarcity pricing mechanism pursuant to the provisions of Public Utility Commission of Texas ("PUCT") Substantive Rule 25.505(g).

Our analysis indicates that the market performed competitively in 2008. However, the report generally confirms prior findings that the current market rules and procedures are resulting in systemic inefficiencies. Many of these findings can be found in six previous reports we have issued regarding the ERCOT electricity markets.[1] These reports included a number of recommendations designed to improve the performance of the current ERCOT markets. Many of these recommendations were considered by ERCOT working groups and some were embodied in protocol revision requests ("PRRs"). Most of the remaining recommendations will be addressed by the introduction of the nodal market design in late 2010.

One of the most important functions of any electricity market is to manage the flows of power over the transmission network, limiting additional power flows over transmission facilities when they reach their operating limits. As discussed in previous reports, this is also one of the most significant shortcomings of the current ERCOT zonal market design. The zonal market structure is an inherently inefficient model for managing transmission congestion. The zonal market model also suffers from the need to predict and define ahead of time those constraints that can be reasonably managed by using zonal congestion management techniques. Given the dynamic nature of supply, demand and the topology of the transmission system, such predictions can often be incorrect. This was the case in 2008, resulting in significant price excursions in the South and

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1 "ERCOT State of the Market Report 2003", Potomac Economics, August 2004 ("2003 SOM Report"); "2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets", Potomac Economics, November 2004; "ERCOT State of the Market Report 2004", Potomac Economics, July 2005 ("2004 SOM Report"); "ERCOT State of the Market Report 2005", Potomac Economics, July 2006 ("2005 SOM Report"); "ERCOT State of the Market Report 2006", Potomac Economics, August 2007 ("2006 SOM Report"); and "ERCOT State of the Market Report 2007", Potomac Economics, August 2008 ("2007 SOM Report").

Houston Zones during the months of April, May and early June until an expedited PRR that modified ERCOT congestion management procedures was implemented.

The wholesale market should function more efficiently under the nodal market design by providing better incentives to market participants, facilitating more efficient commitment and dispatch of generation, and improving ERCOT's operational control of the system. The congestion on all transmission paths and facilities will be managed through market-based mechanisms in the nodal market. In contrast, under the current zonal market design, transmission congestion is most frequently resolved through non-transparent, non-market-based procedures.

Under the nodal market, unit-specific dispatch will allow ERCOT to more fully utilize generating resources than the current market, which frequently exhibits price spikes even when generating capacity is not fully utilized. The nodal market will also allow ERCOT to increase the economic and reliable utilization of scarce transmission resources well beyond that attainable in the zonal market. Finally, the nodal market will produce price signals that better indicate where new generation is most needed for managing congestion and maintaining reliability. In the long-term, these enhancements to overall market efficiency should translate into substantial savings for consumers.

A. Review of Market Outcomes

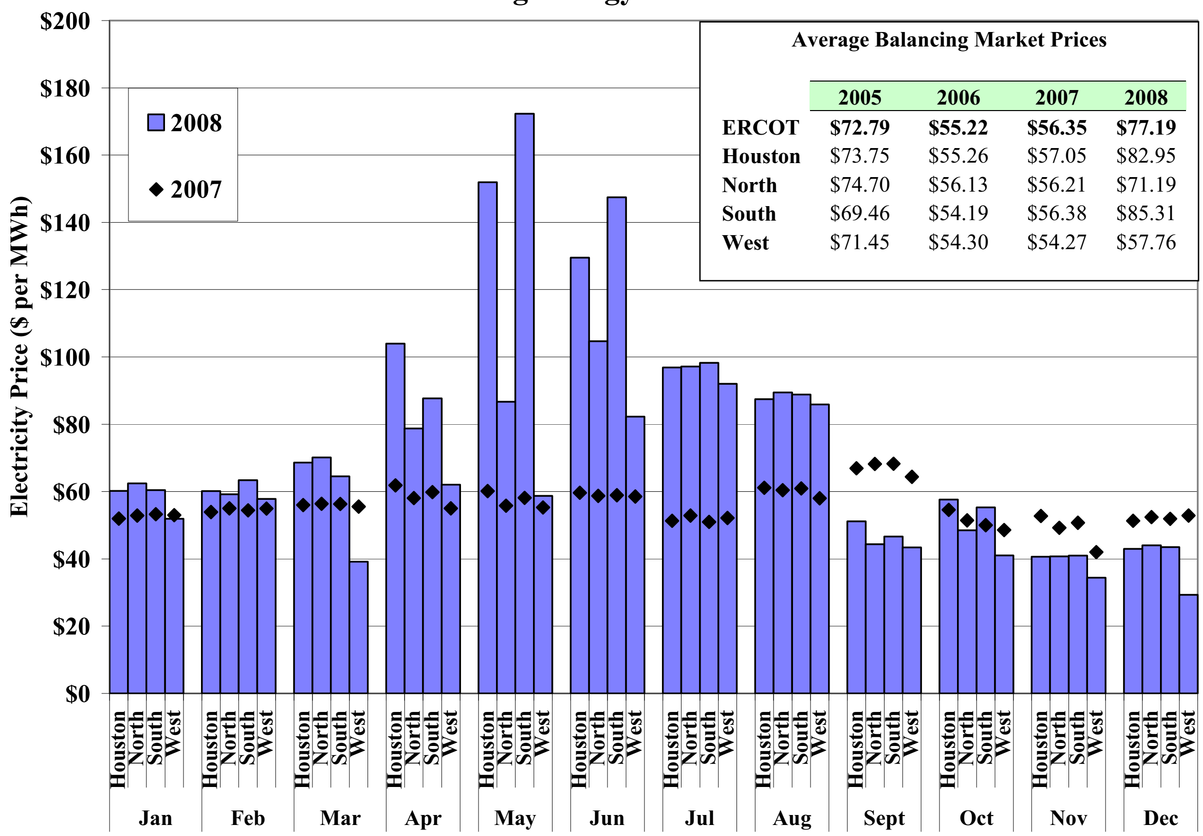
1. Balancing Energy Prices

The balancing energy market allows participants to make real-time purchases and sales of energy to supplement their forward bilateral contracts. While on average only a relatively small portion of the electricity produced in ERCOT is cleared through the balancing energy market, its role is critical in the overall wholesale market. The balancing energy market governs real-time dispatch of generation by altering where energy is produced to: a) balance supply and demand; b) manage interzonal congestion, and c) displace higher-cost energy with lower-cost energy given the energy offers of the Qualify Scheduling Entities ("QSEs").

In addition, the balancing energy prices also provide a vital signal of the value of power for market participants entering into forward contracts. Although most power is purchased through forward contracts of varying duration, the spot prices emerging from the balancing energy market should directly affect forward contract prices.

As shown in the following figure, balancing energy market prices were 37 percent higher in 2008 than in 2007, with May and June 2008 showing the largest increases from the same months in 2007. The average natural gas price in 2008 increased 28 percent over 2007 levels, with monthly changes ranging from a 87 percent increase in July ($5.91 per MMBtu in July 2007 and $11.05 per MMBtu in July 2008) to an 20 percent decrease in December ($6.63 per MMBtu in December 2007 and $5.29 per MMBtu in December 2008). Natural gas is typically the marginal fuel in the ERCOT market. Hence, the movements in wholesale energy prices from 2007 to 2008 were largely a function of natural gas price levels.

Balancing Energy Market Prices



	2005	2006	2007	2008
ERCOT	**$72.79**	**$55.22**	**$56.35**	**$77.19**
Houston	$73.75	$55.26	$57.05	$82.95
North	$74.70	$56.13	$56.21	$71.19
South	$69.46	$54.19	$56.38	$85.31
West	$71.45	$54.30	$54.27	$57.76

Although fuel price fluctuations are the dominant factor driving electricity prices in the ERCOT wholesale market, fuel prices alone do not explain all of the price outcomes. At least five other factors provided a meaningful contribution to price outcomes in 2008.

STP Attachment 8

REPORT ON THE CAPACITY, DEMAND, AND RESERVES IN THE ERCOT REGION

May 2010

ERCOT
2705 West Lake Drive
Taylor, Texas 76574

2010 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary

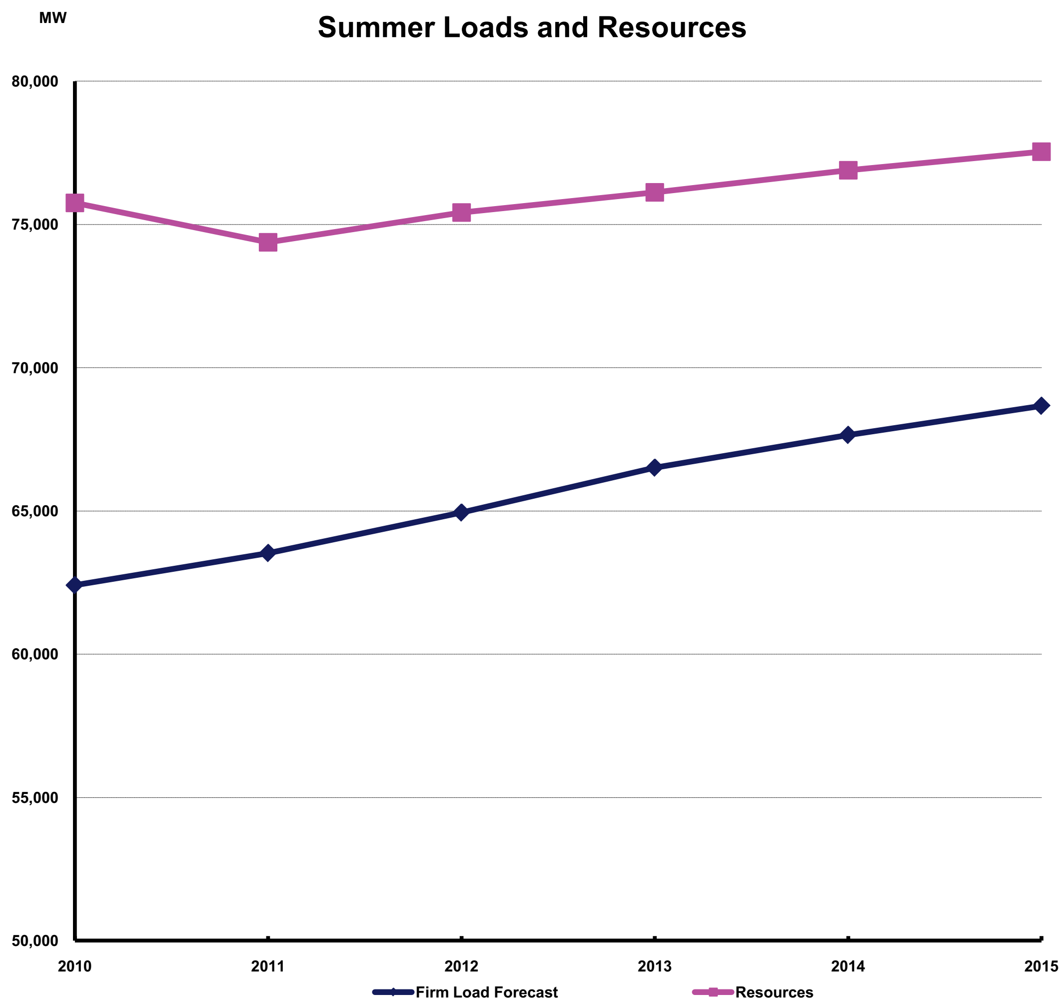
Load Forecast:	2010	2011	2012	2013	2014	2015
Total Summer Peak Demand, MW	64,052	65,206	66,658	68,265	69,451	70,517
less LAARs Serving as Responsive Reserve, MW	1,062	1,062	1,062	1,062	1,062	1,062
less LAARs Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0
less Emergency Interruptible Load Service	336	370	407	447	492	541
less BULs, MW	0	0	0	0	0	0
less Energy Efficiency Programs (per HB3693)	242	242	242	242	242	242
Firm Load Forecast, MW	**62,412**	**63,532**	**64,947**	**66,514**	**67,655**	**68,672**

Resources:	2010	2011	2012	2013	2014	2015
Installed Capacity, MW	66,228	64,372	64,372	64,372	64,372	64,372
Capacity from Private Networks, MW	4,803	4,803	4,803	4,803	4,803	4,803
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	793	793	793	793	793	793
RMR Units to be under Contract, MW	688	0	0	0	0	0
Operational Generation, MW	**72,512**	**69,968**	**69,968**	**69,968**	**69,968**	**69,968**
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Switchable Units, MW	2,848	2,848	2,848	2,848	2,848	2,848
Available Mothballed Generation , MW	0	0	0	0	0	0
Planned Units (not wind) with Signed IA and Air Permit, MW	0	978	2,003	2,653	3,409	4,059
ELCC of Planned Wind Units with Signed IA, MW	0	30	43	95	115	115
Total Resources, MW	**75,913**	**74,377**	**75,415**	**76,117**	**76,893**	**77,543**
less Switchable Units Unavailable to ERCOT, MW	158	0	0	0	0	0
less Retiring Units, MW	0	0	0	0	0	0
Resources, MW	**75,755**	**74,377**	**75,415**	**76,117**	**76,893**	**77,543**
Reserve Margin	**21.4%**	**17.1%**	**16.1%**	**14.4%**	**13.7%**	**12.9%**
(Resources - Firm Load Forecast)/Firm Load Forecast						

Other Potential Resources:	**553**	**13,691**	**21,252**	**23,402**	**25,813**	**31,757**
Mothballed Capacity , MW	0	5,022	5,022	5,022	5,022	5,022
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Planned Units in Full Interconnection Study Phase, MW	0	8,116	15,677	17,827	20,238	26,182

2010 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary



Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
A von Rosenberg 1-CT1	BRAUNIG_AVR1_CT1	Bexar	Gas	South	2000	145.0	145.0	145.0	145.0	145.0	145.0
A von Rosenberg 1-CT2	BRAUNIG_AVR1_CT2	Bexar	Gas	South	2000	145.0	145.0	145.0	145.0	145.0	145.0
A von Rosenberg 1-ST1	BRAUNIG_AVR1_ST	Bexar	Gas	South	2000	160.0	160.0	160.0	160.0	160.0	160.0
AEDOMG 1	DG_SUMMI_1UNIT	Travis	Gas	South	2004	5.0	5.0	5.0	5.0	5.0	5.0
AES Deepwater	APD_APD_G1	Harris	Other	Houston	1986	138.0	138.0	138.0	138.0	138.0	138.0
Amistad Hydro 1	AMISTAD_AMISTAG1	Val Verde	Hydro	South	1983	38.0	38.0	38.0	38.0	38.0	38.0
Amistad Hydro 2	AMISTAD_AMISTAG2	Val Verde	Hydro	South	1983	38.0	38.0	38.0	38.0	38.0	38.0
Atascocita 1	_HB_DG1	Harris	Biomass	Houston	2003	10.1	10.1	10.1	10.1	10.1	10.1
Atkins 7	ATKINS_ATKINSG7	Brazos	Gas	North	1973	20.0	20.0	20.0	20.0	20.0	20.0
Austin 1	AUSTPL_AUSTING1	Travis	Hydro	South	1940	8.0	8.0	8.0	8.0	8.0	8.0
Austin 2	AUSTPL_AUSTING2	Travis	Hydro	South	1940	9.0	9.0	9.0	9.0	9.0	9.0
Austin Landfill Gas	DG_SPRIN_4UNITS	Travis	Other	South	1988	6.4	6.4	6.4	6.4	6.4	6.4
B M Davis 1	B_DAVIS_B_DAVIG1	Nueces	Gas	South	1974	335.0	335.0	335.0	335.0	335.0	335.0
B M Davis 2	B_DAVIS_B_DAVIG2	Nueces	Gas	South	1976	344.0	344.0	344.0	344.0	344.0	344.0
B M Davis 3	B_DAVIS_B_DAVIG3	Nueces	Gas	South	2009	190.0	190.0	190.0	190.0	190.0	190.0
B M Davis 4	B_DAVIS_B_DAVIG4	Nueces	Gas	South	2009	190.0	190.0	190.0	190.0	190.0	190.0
Bastrop Energy Center 1	BASTEN_GTG1100	Bastrop	Gas	South	2002	152.0	152.0	152.0	152.0	152.0	152.0
Bastrop Energy Center 2	BASTEN_GTG2100	Bastrop	Gas	South	2002	150.0	150.0	150.0	150.0	150.0	150.0
Bastrop Energy Center 3	BASTEN_ST0100	Bastrop	Gas	South	2002	233.0	233.0	233.0	233.0	233.0	233.0
Baytown 1	TRN_DG1	Chambers	Biomass	Houston	2003	3.9	3.9	3.9	3.9	3.9	3.9
Big Brown 1	BBSES_UNIT1	Freestone	Coal	North	1971	617.0	617.0	617.0	617.0	617.0	617.0
Big Brown 2	BBSES_UNIT2	Freestone	Coal	North	1972	615.0	615.0	615.0	615.0	615.0	615.0
Bio Energy Partners	DG_BIOE_2UNITS	Denton	Gas	North	1988	5.6	5.6	5.6	5.6	5.6	5.6
Bluebonnet 1	_LB_DG1	Harris	Biomass	Houston	2003	3.9	3.9	3.9	3.9	3.9	3.9
Bosque County Peaking 1	BOSQUESW_BSQSU_1	Bosque	Gas	North	2000	153.0	153.0	153.0	153.0	153.0	153.0
Bosque County Peaking 2	BOSQUESW_BSQSU_2	Bosque	Gas	North	2000	153.0	153.0	153.0	153.0	153.0	153.0
Bosque County Peaking 3	BOSQUESW_BSQSU_3	Bosque	Gas	North	2001	154.0	154.0	154.0	154.0	154.0	154.0
Bosque County Peaking 4	BOSQUESW_BSQSU_4	Bosque	Gas	North	2001	83.0	83.0	83.0	83.0	83.0	83.0
Bosque County Unit 5	BOSQUESW_BSQSU_5	Bosque	Gas	North	2009	240.0	240.0	240.0	240.0	240.0	240.0
Brazos Valley 1	BVE_Unit1	Ft Bend	Gas	Houston	2003	163.0	163.0	163.0	163.0	163.0	163.0
Brazos Valley 2	BVE_Unit2	Ft Bend	Gas	Houston	2003	163.0	163.0	163.0	163.0	163.0	163.0
Brazos Valley 3	BVE_Unit3	Ft Bend	Gas	Houston	2003	253.0	253.0	253.0	253.0	253.0	253.0
Buchanan 1	BUCHAN_BUCHANG1	Llano	Hydro	South	1938	18.0	18.0	18.0	18.0	18.0	18.0
Buchanan 2	BUCHAN_BUCHANG2	Llano	Hydro	South	1938	18.0	18.0	18.0	18.0	18.0	18.0
Buchanan 3	BUCHAN_BUCHANG3	Llano	Hydro	South	1950	18.0	18.0	18.0	18.0	18.0	18.0
Calenergy (Falcon Seaboard) 1	FLCNS_UNIT1	Howard	Gas	West	1987	75.0	75.0	75.0	75.0	75.0	75.0
Calenergy (Falcon Seaboard) 2	FLCNS_UNIT2	Howard	Gas	West	1987	75.0	75.0	75.0	75.0	75.0	75.0
Calenergy (Falcon Seaboard) 3	FLCNS_UNIT3	Howard	Gas	West	1988	70.0	70.0	70.0	70.0	70.0	70.0
Canyon 1	CANYHY_CANYHYG1	Comal	Hydro	South	1989	3.0	3.0	3.0	3.0	3.0	3.0
Canyon 2	CANYHY_CANYHYG2	Comal	Hydro	South	1989	3.0	3.0	3.0	3.0	3.0	3.0
Cedar Bayou 1	CBY_CBY_G1	Chambers	Gas	Houston	1970	745.0	745.0	745.0	745.0	745.0	745.0
Cedar Bayou 2	CBY_CBY_G2	Chambers	Gas	Houston	1972	749.0	749.0	749.0	749.0	749.0	749.0
Cedar Bayou 4	CBY4_CT41	Chambers	Gas	Houston	2009	169.0	169.0	169.0	169.0	169.0	169.0
Cedar Bayou 5	CBY4_CT42	Chambers	Gas	Houston	2009	169.0	169.0	169.0	169.0	169.0	169.0
Cedar Bayou 6	CBY4_ST04	Chambers	Gas	Houston	2009	180.0	180.0	180.0	180.0	180.0	180.0
Channel Energy Deepwater	CHEDPW_GT2	Harris	Gas	Houston	2002	182.0	182.0	182.0	182.0	182.0	182.0
Coastal Plains RDF	_AV_DG1	Galveston	Biomass	Houston	2003	6.7	6.7	6.7	6.7	6.7	6.7
Coleto Creek	COLETO_COLETOG1	Goliad	Coal	South	1980	632.0	632.0	632.0	632.0	632.0	632.0
Colorado Bend Energy Center	CBEC_GT1	Wharton	Gas	Houston	2007	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_GT2	Wharton	Gas	Houston	2007	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_GT3	Wharton	Gas	Houston	2008	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_GT4	Wharton	Gas	Houston	2008	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_STG1	Wharton	Gas	Houston	2007	105.0	105.0	105.0	105.0	105.0	105.0
Colorado Bend Energy Center	CBEC_STG2	Wharton	Gas	Houston	2008	105.0	105.0	105.0	105.0	105.0	105.0
Comanche Peak 1	CPSES_UNIT1	Somervell	Nuclear	North	1990	1209.0	1209.0	1209.0	1209.0	1209.0	1209.0
Comanche Peak 2	CPSES_UNIT2	Somervell	Nuclear	North	1993	1158.0	1158.0	1158.0	1158.0	1158.0	1158.0
Corrugated Medium Mill	DG_FORSW_1UNIT	Kaufman	Gas	North	2008	4.8	4.8	4.8	4.8	4.8	4.8
Covel Gardens LG Power Station	DG_MEDIN_1UNIT	Bexar	Other	South	2005	10.0	10.0	10.0	10.0	10.0	10.0
CVC Channelview 1	CVC_CVC_G1	Harris	Gas	Houston	2008	156.0	156.0	156.0	156.0	156.0	156.0
CVC Channelview 2	CVC_CVC_G2	Harris	Gas	Houston	2008	158.0	158.0	158.0	158.0	158.0	158.0
CVC Channelview 3	CVC_CVC_G3	Harris	Gas	Houston	2008	160.0	160.0	160.0	160.0	160.0	160.0
CVC Channelview 5	CVC_CVC_G5	Harris	Gas	Houston	2008	122.0	122.0	122.0	122.0	122.0	122.0
Dansby 1	DANSBY_DANSBYG1	Brazos	Gas	North	1978	110.0	110.0	110.0	110.0	110.0	110.0
Dansby 2	DANSBY_DANSBYG2	Brazos	Gas	North	2004	48.0	48.0	48.0	48.0	48.0	48.0
Dansby 3	DANSBY_DANSBYG3	Brazos	Gas	North	2009	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek 1	DECKER_DPG1	Travis	Gas	South	1970	315.0	315.0	315.0	315.0	315.0	315.0
Decker Creek 2	DECKER_DPG2	Travis	Gas	South	1977	420.0	420.0	420.0	420.0	420.0	420.0
Decker Creek G1	DECKER_DPGT_1	Travis	Gas	South	1988	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G2	DECKER_DPGT_2	Travis	Gas	South	1988	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G3	DECKER_DPGT_3	Travis	Gas	South	1988	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G4	DECKER_DPGT_4	Travis	Gas	South	1988	48.0	48.0	48.0	48.0	48.0	48.0
DeCordova A	DCSES_CT10	Hood	Gas	North	1990	66.0	66.0	66.0	66.0	66.0	66.0
DeCordova B	DCSES_CT20	Hood	Gas	North	1990	66.0	66.0	66.0	66.0	66.0	66.0
DeCordova C	DCSES_CT30	Hood	Gas	North	1990	66.0	66.0	66.0	66.0	66.0	66.0
DeCordova D	DCSES_CT40	Hood	Gas	North	1990	66.0	66.0	66.0	66.0	66.0	66.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
Deer Park Energy Center 1	DDPEC_GT1	Harris	Gas	Houston	2002	163.0	163.0	163.0	163.0	163.0	163.0
Deer Park Energy Center 2	DDPEC_GT2	Harris	Gas	Houston	2002	157.0	157.0	157.0	157.0	157.0	157.0
Deer Park Energy Center 3	DDPEC_GT3	Harris	Gas	Houston	2002	158.0	158.0	158.0	158.0	158.0	158.0
Deer Park Energy Center 4	DDPEC_GT4	Harris	Gas	Houston	2002	157.0	157.0	157.0	157.0	157.0	157.0
Deer Park Energy Center S	DDPEC_ST1	Harris	Gas	Houston	2002	238.0	238.0	238.0	238.0	238.0	238.0
Denison Dam 1	DNDAM_DENISOG1	Grayson	Hydro	North	1944	40.0	40.0	40.0	40.0	40.0	40.0
Denison Dam 2	DNDAM_DENISOG2	Grayson	Hydro	North	1944	40.0	40.0	40.0	40.0	40.0	40.0
DFW Gas Recovery	DG_BIO2_4UNITS	Denton	Biomass	North	1980	6.4	6.4	6.4	6.4	6.4	6.4
Dunlop (Schumansville) 1	DG_SCHUM_2UNITS	Guadalupe	Hydro	South	1927	3.6	3.6	3.6	3.6	3.6	3.6
Eagle Pass 1	EAGLE_HY_EAGLE_HY1	Maverick	Hydro	South	1954	2.0	2.0	2.0	2.0	2.0	2.0
Eagle Pass 2	EAGLE_HY_EAGLE_HY2	Maverick	Hydro	South	1954	2.0	2.0	2.0	2.0	2.0	2.0
Eagle Pass 3	EAGLE_HY_EAGLE_HY3	Maverick	Hydro	South	1954	2.0	2.0	2.0	2.0	2.0	2.0
Ennis Power Station 1	ETCCS_UNIT1	Ellis	Gas	North	2002	116.0	116.0	116.0	116.0	116.0	116.0
Ennis Power Station 2	ETCCS_CT1	Ellis	Gas	North	2002	196.0	196.0	196.0	196.0	196.0	196.0
ExTex La Porte Power Station (AirPro	_AZ__AZ_G1	Harris	Gas	Houston	2001	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Power Station (AirPro	_AZ__AZ_G2	Harris	Gas	Houston	2001	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Power Station (AirPro	_AZ__AZ_G3	Harris	Gas	Houston	2001	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Power Station (AirPro	_AZ__AZ_G4	Harris	Gas	Houston	2001	38.0	38.0	38.0	38.0	38.0	38.0
Falcon Hydro 1	FALCON_FALCONG1	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 2	FALCON_FALCONG2	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 3	FALCON_FALCONG3	Starr	Hydro	South	1954	12.0	12.0	12.0	12.0	12.0	12.0
Fayette Power Project 1	FPPYD1_FPP_G1	Fayette	Coal	South	1979	608.0	608.0	608.0	608.0	608.0	608.0
Fayette Power Project 2	FPPYD1_FPP_G2	Fayette	Coal	South	1980	608.0	608.0	608.0	608.0	608.0	608.0
Fayette Power Project 3	FPPYD2_FPP_G3	Fayette	Coal	South	1988	445.0	445.0	445.0	445.0	445.0	445.0
Forney Energy Center GT11	FRNYPP_GT11	Kaufman	Gas	North	2003	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT12	FRNYPP_GT12	Kaufman	Gas	North	2003	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT13	FRNYPP_GT13	Kaufman	Gas	North	2003	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT21	FRNYPP_GT21	Kaufman	Gas	North	2003	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT22	FRNYPP_GT22	Kaufman	Gas	North	2003	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT23	FRNYPP_GT23	Kaufman	Gas	North	2003	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center STG10	FRNYPP_ST10	Kaufman	Gas	North	2003	415.0	415.0	415.0	415.0	415.0	415.0
Forney Energy Center STG20	FRNYPP_ST20	Kaufman	Gas	North	2003	415.0	415.0	415.0	415.0	415.0	415.0
Freestone Energy Center 1	FREC_GT1	Freestone	Gas	North	2002	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 2	FREC_GT2	Freestone	Gas	North	2002	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 3	FREC_ST3	Freestone	Gas	North	2002	175.0	175.0	175.0	175.0	175.0	175.0
Freestone Energy Center 4	FREC_GT4	Freestone	Gas	North	2002	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 5	FREC_GT5	Freestone	Gas	North	2002	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 6	FREC_ST6	Freestone	Gas	North	2002	175.0	175.0	175.0	175.0	175.0	175.0
Fresno Energy	DG__SO_1UNIT	Fort Bend	Other	Houston	2010	1.6	1.6	1.6	1.6	1.6	1.6
Frontera 1	FRONTERA_FRONTEG1	Hidalgo	Gas	South	1999	146.0	146.0	146.0	146.0	146.0	146.0
Frontera 2	FRONTERA_FRONTEG2	Hidalgo	Gas	South	1999	148.0	148.0	148.0	148.0	148.0	148.0
Frontera 3	FRONTERA_FRONTEG3	Hidalgo	Gas	South	2000	173.0	173.0	173.0	173.0	173.0	173.0
FW Regional LFG Generation Facility	DG_RDLML_1UNIT	Tarrant	Other	North	1988	1.5	1.5	1.5	1.5	1.5	1.5
GBRA 4 & 5	DG_LKWDT_2UNITS	Gonzales	Other	South	1931	4.8	4.8	4.8	4.8	4.8	4.8
Gibbons Creek 1	GIBCRK_GIB_CRG1	Grimes	Coal	North	1982	470.0	470.0	470.0	470.0	470.0	470.0
Graham 1	GRSES_UNIT1	Young	Gas	North	1960	230.0	230.0	230.0	230.0	230.0	230.0
Graham 2	GRSES_UNIT2	Young	Gas	North	1969	390.0	390.0	390.0	390.0	390.0	390.0
Granite Shoals 1	WIRTZ_WIRTZ_G1	Burnet	Hydro	South	1951	30.0	30.0	30.0	30.0	30.0	30.0
Granite Shoals 2	WIRTZ_WIRTZ_G2	Burnet	Hydro	South	1951	30.0	30.0	30.0	30.0	30.0	30.0
Greens Bayou 5	GBY_GBY_5	Harris	Gas	Houston	1973	406.0	406.0	406.0	406.0	406.0	406.0
Greens Bayou 73	GBY_GBYGT73	Harris	Gas	Houston	1976	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 74	GBY_GBYGT74	Harris	Gas	Houston	1976	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 81	GBY_GBYGT81	Harris	Gas	Houston	1976	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 82	GBY_GBYGT82	Harris	Gas	Houston	1976	56.0	56.0	56.0	56.0	56.0	56.0
Greens Bayou 83	GBY_GBYGT83	Harris	Gas	Houston	1976	56.0	56.0	56.0	56.0	56.0	56.0
Greens Bayou 84	GBY_GBYGT84	Harris	Gas	Houston	1976	56.0	56.0	56.0	56.0	56.0	56.0
Guadalupe Generating Station 1	GUADG_GAS1	Guadalupe	Gas	South	2000	151.0	151.0	151.0	151.0	151.0	151.0
Guadalupe Generating Station 2	GUADG_GAS2	Guadalupe	Gas	South	2000	151.0	151.0	151.0	151.0	151.0	151.0
Guadalupe Generating Station 3	GUADG_GAS3	Guadalupe	Gas	South	2000	149.0	149.0	149.0	149.0	149.0	149.0
Guadalupe Generating Station 4	GUADG_GAS4	Guadalupe	Gas	South	2001	152.0	152.0	152.0	152.0	152.0	152.0
Guadalupe Generating Station 5	GUADG_STM5	Guadalupe	Gas	South	2001	170.0	170.0	170.0	170.0	170.0	170.0
Guadalupe Generating Station 6	GUADG_STM6	Guadalupe	Gas	South	2001	169.0	169.0	169.0	169.0	169.0	169.0
Handley 3	HLSES_UNIT3	Tarrant	Gas	North	1963	395.0	395.0	395.0	395.0	395.0	395.0
Handley 4	HLSES_UNIT4	Tarrant	Gas	North	1976	435.0	435.0	435.0	435.0	435.0	435.0
Handley 5	HLSES_UNIT5	Tarrant	Gas	North	1977	435.0	435.0	435.0	435.0	435.0	435.0
Hays Energy Facility 1	HAYSEN_HAYSENG1	Hays	Gas	South	2002	216.0	216.0	216.0	216.0	216.0	216.0
Hays Energy Facility 2	HAYSEN_HAYSENG2	Hays	Gas	South	2002	216.0	216.0	216.0	216.0	216.0	216.0
Hays Energy Facility 3	HAYSEN_HAYSENG3	Hays	Gas	South	2002	225.0	225.0	225.0	225.0	225.0	225.0
Hays Energy Facility 4	HAYSEN_HAYSENG4	Hays	Gas	South	2002	225.0	225.0	225.0	225.0	225.0	225.0
Hidalgo 1	DUKE_DUKE_GT1	Hidalgo	Gas	South	2000	141.0	141.0	141.0	141.0	141.0	141.0
Hidalgo 2	DUKE_DUKE_GT2	Hidalgo	Gas	South	2000	141.0	141.0	141.0	141.0	141.0	141.0
Hidalgo 3	DUKE_DUKE_ST1	Hidalgo	Gas	South	2000	168.0	168.0	168.0	168.0	168.0	168.0
Inks 1	INKSDA_INKS_G1	Llano	Hydro	South	1938	14.0	14.0	14.0	14.0	14.0	14.0
J K Spruce 1	CALAVERS_JKS1	Bexar	Coal	South	1992	555.0	555.0	555.0	555.0	555.0	555.0
J K Spruce 2	CALAVERS_JKS2	Bexar	Coal	South	2009	772.0	772.0	772.0	772.0	772.0	772.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
J T Deely 1	CALAVERS_JTD1	Bexar	Coal	South	1977	440.0	440.0	440.0	440.0	440.0	440.0
J T Deely 2	CALAVERS_JTD2	Bexar	Coal	South	1978	440.0	440.0	440.0	440.0	440.0	440.0
Jack County Generation Facility 1	JACKCNTY_CT1	Jack	Gas	North	2005	142.0	142.0	142.0	142.0	142.0	142.0
Jack County Generation Facility 2	JACKCNTY_CT2	Jack	Gas	North	2005	142.0	142.0	142.0	142.0	142.0	142.0
Jack County Generation Facility 3	JACKCNTY_STG	Jack	Gas	North	2005	281.0	281.0	281.0	281.0	281.0	281.0
Johnson County Generation Facility 1	TEN_CT1	Johnson	Gas	North	1992	150.0	150.0	150.0	150.0	150.0	150.0
Johnson County Generation Facility 2	TEN_STG	Johnson	Gas	North	1992	106.0	106.0	106.0	106.0	106.0	106.0
Lake Hubbard 1	LHSES_UNIT1	Dallas	Gas	North	1970	392.0	392.0	392.0	392.0	392.0	392.0
Lake Hubbard 2	LH2SES_UNIT2	Dallas	Gas	North	1970	524.0	524.0	524.0	524.0	524.0	524.0
Lamar Power Project CT11	LPCCS_CT11	Lamar	Gas	North	2000	156.0	156.0	156.0	156.0	156.0	156.0
Lamar Power Project CT12	LPCCS_CT12	Lamar	Gas	North	2000	157.0	157.0	157.0	157.0	157.0	157.0
Lamar Power Project CT21	LPCCS_CT21	Lamar	Gas	North	2000	156.0	156.0	156.0	156.0	156.0	156.0
Lamar Power Project CT22	LPCCS_CT22	Lamar	Gas	North	2000	157.0	157.0	157.0	157.0	157.0	157.0
Lamar Power Project STG1	LPCCS_UNIT1	Lamar	Gas	North	2001	198.0	198.0	198.0	198.0	198.0	198.0
Lamar Power Project STG2	LPCCS_UNIT2	Lamar	Gas	North	2001	198.0	198.0	198.0	198.0	198.0	198.0
Laredo Peaking 4	LARDVFTN_G4	Webb	Gas	South	2008	94.0	94.0	94.0	94.0	94.0	94.0
Laredo Peaking 5	LARDVFTN_G5	Webb	Gas	South	2008	94.0	94.0	94.0	94.0	94.0	94.0
Leon Creek 3	LEON_CRK_LCP3G3	Bexar	Gas	South	1953	56.0	56.0	56.0	56.0	56.0	56.0
Leon Creek 4	LEON_CRK_LCP4G4	Bexar	Gas	South	1959	88.0	88.0	88.0	88.0	88.0	88.0
Leon Creek Peaking 1	LEON_CRK_LCPCT1	Bexar	Gas	South	2004	45.0	45.0	45.0	45.0	45.0	45.0
Leon Creek Peaking 2	LEON_CRK_LCPCT2	Bexar	Gas	South	2004	45.0	45.0	45.0	45.0	45.0	45.0
Leon Creek Peaking 3	LEON_CRK_LCPCT3	Bexar	Gas	South	2004	45.0	45.0	45.0	45.0	45.0	45.0
Leon Creek Peaking 4	LEON_CRK_LCPCT4	Bexar	Gas	South	2004	45.0	45.0	45.0	45.0	45.0	45.0
Lewisville 1	DG_LWSVL_1UNIT	Denton	Hydro	North	1992	2.8	2.8	2.8	2.8	2.8	2.8
Limestone 1	LEG_LEG_G1	Limestone	Coal	North	1985	831.0	831.0	831.0	831.0	831.0	831.0
Limestone 2	LEG_LEG_G2	Limestone	Coal	North	1986	858.0	858.0	858.0	858.0	858.0	858.0
Lost Pines 1	LOSTPI_LOSTPGT1	Bastrop	Gas	South	2001	167.0	167.0	167.0	167.0	167.0	167.0
Lost Pines 2	LOSTPI_LOSTPGT2	Bastrop	Gas	South	2001	164.0	164.0	164.0	164.0	164.0	164.0
Lost Pines 3	LOSTPI_LOSTPST1	Bastrop	Gas	South	2001	184.0	184.0	184.0	184.0	184.0	184.0
Magic Valley 1	NEDIN_NEDIN_G1	Hidalgo	Gas	South	2001	166.0	166.0	166.0	166.0	166.0	166.0
Magic Valley 2	NEDIN_NEDIN_G2	Hidalgo	Gas	South	2001	166.0	166.0	166.0	166.0	166.0	166.0
Magic Valley 3	NEDIN_NEDIN_G3	Hidalgo	Gas	South	2001	204.0	204.0	204.0	204.0	204.0	204.0
Marble Falls 1	MARBFA_MARBFAG1	Burnet	Hydro	South	1951	21.0	21.0	21.0	21.0	21.0	21.0
Marble Falls 2	MARBFA_MARBFAG2	Burnet	Hydro	South	1951	21.0	21.0	21.0	21.0	21.0	21.0
Marshall Ford 1	MARSFO_MARSFOG1	Travis	Hydro	South	1941	36.0	36.0	36.0	36.0	36.0	36.0
Marshall Ford 2	MARSFO_MARSFOG2	Travis	Hydro	South	1941	35.0	35.0	35.0	35.0	35.0	35.0
Marshall Ford 3	MARSFO_MARSFOG3	Travis	Hydro	South	1941	36.0	36.0	36.0	36.0	36.0	36.0
Martin Lake 1	MLSES_UNIT1	Rusk	Coal	North	1977	800.0	800.0	800.0	800.0	800.0	800.0
Martin Lake 2	MLSES_UNIT2	Rusk	Coal	North	1978	800.0	800.0	800.0	800.0	800.0	800.0
Martin Lake 3	MLSES_UNIT3	Rusk	Coal	North	1979	818.0	818.0	818.0	818.0	818.0	818.0
McQueeney (Abbott)	DG_MCQUE_5UNITS	Guadalupe	Hydro	South	1927	8.0	8.0	8.0	8.0	8.0	8.0
Midlothian 1	MDANP_CT1	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 2	MDANP_CT2	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 3	MDANP_CT3	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 4	MDANP_CT4	Ellis	Gas	North	2001	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 5	MDANP_CT5	Ellis	Gas	North	2002	225.0	225.0	225.0	225.0	225.0	225.0
Midlothian 6	MDANP_CT6	Ellis	Gas	North	2002	225.0	225.0	225.0	225.0	225.0	225.0
Monticello 1	MNSES_UNIT1	Titus	Coal	North	1974	583.0	583.0	583.0	583.0	583.0	583.0
Monticello 2	MNSES_UNIT2	Titus	Coal	North	1975	583.0	583.0	583.0	583.0	583.0	583.0
Monticello 3	MNSES_UNIT3	Titus	Coal	North	1978	765.0	765.0	765.0	765.0	765.0	765.0
Morgan Creek A	MGSES_CT1	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek B	MGSES_CT2	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek C	MGSES_CT3	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek D	MGSES_CT4	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek E	MGSES_CT5	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek F	MGSES_CT6	Mitchell	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Morris Sheppard	MSP_MSP_1	Palo Pinto	Hydro	North	1942	12.0	12.0	12.0	12.0	12.0	12.0
Morris Sheppard	MSP_MSP_2	Palo Pinto	Hydro	North	1942	12.0	12.0	12.0	12.0	12.0	12.0
Mountain Creek 6	MCSES_UNIT6	Dallas	Gas	North	1956	120.0	120.0	120.0	120.0	120.0	120.0
Mountain Creek 7	MCSES_UNIT7	Dallas	Gas	North	1958	115.0	115.0	115.0	115.0	115.0	115.0
Mountain Creek 8	MCSES_UNIT8	Dallas	Gas	North	1967	565.0	565.0	565.0	565.0	565.0	565.0
Nelson Gardens Landfill 1	DG_PEARS_2UNITS	Bexar	Other	South	1990	3.6	3.6	3.6	3.6	3.6	3.6
Nueces Bay 7	NUECES_B_NUECESG7	Nueces	Gas	South	1972	351.0	351.0	351.0	351.0	351.0	351.0
Nueces Bay 8	NUECES_B_NUECESG8	Nueces	Gas	South	2010	175.0	175.0	175.0	175.0	175.0	175.0
Nueces Bay 9	NUECES_B_NUECESG9	Nueces	Gas	South	2010	175.0	175.0	175.0	175.0	175.0	175.0
O W Sommers 1	CALAVERS_OWS1	Bexar	Gas	South	1972	400.0	400.0	400.0	400.0	400.0	400.0
O W Sommers 2	CALAVERS_OWS2	Bexar	Gas	South	1974	395.0	395.0	395.0	395.0	395.0	395.0
Oak Grove SES Unit 1	OGSES_UNIT1	Robertson	Coal	North	2009	785.0	785.0	785.0	785.0	785.0	785.0
Oak Grove SES Unit 2	OGSES_UNIT2	Robertson	Coal	North	2009	796.0	796.0	796.0	796.0	796.0	796.0
Oak Ridge North 1-3	DG__RA_3UNITS	Montgomery	Other	Houston	1993	4.8	4.8	4.8	4.8	4.8	4.8
Odessa-Ector Generating Station C11	OECCS_CT11	Ector	Gas	West	2001	146.0	146.0	146.0	146.0	146.0	146.0
Odessa-Ector Generating Station C12	OECCS_CT12	Ector	Gas	West	2001	139.0	139.0	139.0	139.0	139.0	139.0
Odessa-Ector Generating Station C21	OECCS_CT21	Ector	Gas	West	2001	135.0	135.0	135.0	135.0	135.0	135.0
Odessa-Ector Generating Station C22	OECCS_CT22	Ector	Gas	West	2001	153.0	153.0	153.0	153.0	153.0	153.0
Odessa-Ector Generating Station ST1	OECCS_UNIT1	Ector	Gas	West	2001	210.0	210.0	210.0	210.0	210.0	210.0

Unit Capacities - Summer

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Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
Odessa-Ector Generating Station ST2	OECCS_UNIT2	Ector	Gas	West	2001	210.0	210.0	210.0	210.0	210.0	210.0
Oklaunion 1	OKLA_OKLA_G1	Wilbarger	Coal	West	1986	650.0	650.0	650.0	650.0	650.0	650.0
Paris Energy Center 1	TNSKA_GT1	Lamar	Gas	North	1989	77.0	77.0	77.0	77.0	77.0	77.0
Paris Energy Center 2	TNSKA_GT2	Lamar	Gas	North	1989	80.0	80.0	80.0	80.0	80.0	80.0
Paris Energy Center 3	TNSKA_STG	Lamar	Gas	North	1990	88.0	88.0	88.0	88.0	88.0	88.0
PasGen	PSG_GT2	Harris	Gas	Houston	1980	161.0	161.0	161.0	161.0	161.0	161.0
PasGen	PSG_GT3	Harris	Gas	Houston	1980	161.0	161.0	161.0	161.0	161.0	161.0
PasGen	PSG_ST2	Harris	Gas	Houston	1980	177.0	177.0	177.0	177.0	177.0	177.0
Pearsall 1	PEARSALL_PEARS_1	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 2	PEARSALL_PEARS_2	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 3	PEARSALL_PEARS_3	Frio	Gas	South	1961	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall Engine Plant	PEARSAL2_ENG1	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG2	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG3	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG4	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG5	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG6	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG7	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG8	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG9	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG10	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG11	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG12	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG13	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG14	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG15	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG16	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG17	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG18	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG19	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG20	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG21	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG22	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG23	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG24	Frio	Gas	South	2010	8.4	8.4	8.4	8.4	8.4	8.4
Permian Basin A	PB2SES_CT1	Ward	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Permian Basin B	PB2SES_CT2	Ward	Gas	West	1988	65.0	65.0	65.0	65.0	65.0	65.0
Permian Basin C	PB2SES_CT3	Ward	Gas	West	1988	68.0	68.0	68.0	68.0	68.0	68.0
Permian Basin D	PB2SES_CT4	Ward	Gas	West	1990	69.0	69.0	69.0	69.0	69.0	69.0
Permian Basin E	PB2SES_CT5	Ward	Gas	West	1990	70.0	70.0	70.0	70.0	70.0	70.0
Powerlane Plant 1	STEAM_STEAM_1	Hunt	Gas	North	1966	20.0	20.0	20.0	20.0	20.0	20.0
Powerlane Plant 2	STEAM_STEAM_2	Hunt	Gas	North	1967	1.0	1.0	1.0	1.0	1.0	1.0
Powerlane Plant 3	STEAM_STEAM_3	Hunt	Gas	North	1978	41.0	41.0	41.0	41.0	41.0	41.0
Quail Run Energy GT1	QALSW_GT2	Ector	Gas	West	2007	70.0	70.0	70.0	70.0	70.0	70.0
Quail Run Energy GT2	QALSW_GT3	Ector	Gas	West	2008	70.0	70.0	70.0	70.0	70.0	70.0
Quail Run Energy GT3	QALSW_STG1	Ector	Gas	West	2007	90.0	90.0	90.0	90.0	90.0	90.0
Quail Run Energy GT4	QALSW_STG2	Ector	Gas	West	2008	90.0	90.0	90.0	90.0	90.0	90.0
Quail Run Energy STG1	QALSW_GT1	Ector	Gas	West	2007	70.0	70.0	70.0	70.0	70.0	70.0
Quail Run Energy STG2	QALSW_GT4	Ector	Gas	West	2008	70.0	70.0	70.0	70.0	70.0	70.0
R W Miller 1	MIL_MILLERG1	Palo Pinto	Gas	North	1968	75.0	75.0	75.0	75.0	75.0	75.0
R W Miller 2	MIL_MILLERG2	Palo Pinto	Gas	North	1972	120.0	120.0	120.0	120.0	120.0	120.0
R W Miller 3	MIL_MILLERG3	Palo Pinto	Gas	North	1975	208.0	208.0	208.0	208.0	208.0	208.0
R W Miller 4	MIL_MILLERG4	Palo Pinto	Gas	North	1994	104.0	104.0	104.0	104.0	104.0	104.0
R W Miller 5	MIL_MILLERG5	Palo Pinto	Gas	North	1994	104.0	104.0	104.0	104.0	104.0	104.0
Ray Olinger 1	OLINGR_OLING_1	Collin	Gas	North	1967	78.0	78.0	78.0	78.0	78.0	78.0
Ray Olinger 2	OLINGR_OLING_2	Collin	Gas	North	1971	107.0	107.0	107.0	107.0	107.0	107.0
Ray Olinger 3	OLINGR_OLING_3	Collin	Gas	North	1975	146.0	146.0	146.0	146.0	146.0	146.0
Ray Olinger 4	OLINGR_OLING_4	Collin	Gas	North	2001	75.0	75.0	75.0	75.0	75.0	75.0
Rayburn 1	RAYBURN_RAYBURG1	Victoria	Gas	South	1963	11.0	11.0	11.0	11.0	11.0	11.0
Rayburn 10	RAYBURN_RAYBURG10	Victoria	Gas	South	2003	40.0	40.0	40.0	40.0	40.0	40.0
Rayburn 2	RAYBURN_RAYBURG2	Victoria	Gas	South	1963	11.0	11.0	11.0	11.0	11.0	11.0
Rayburn 3	RAYBURN_RAYBURG3	Victoria	Gas	South	1965	24.0	24.0	24.0	24.0	24.0	24.0
Rayburn 7	RAYBURN_RAYBURG7	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 8	RAYBURN_RAYBURG8	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 9	RAYBURN_RAYBURG9	Victoria	Gas	South	2003	50.0	50.0	50.0	50.0	50.0	50.0
RGV Sugar Mill	DG_S_SNR_UNIT1	Hidalgo	Biomass	South	1973	4.5	4.5	4.5	4.5	4.5	4.5
Rhodia Houston Plant	DG__HG_2UNITS	Harris	Other	Houston	1970	7.5	7.5	7.5	7.5	7.5	7.5
Rio Nogales 1	RIONOG_CT1	Guadalupe	Gas	South	2002	142.0	142.0	142.0	142.0	142.0	142.0
Rio Nogales 2	RIONOG_CT2	Guadalupe	Gas	South	2002	142.0	142.0	142.0	142.0	142.0	142.0
Rio Nogales 3	RIONOG_CT3	Guadalupe	Gas	South	2002	142.0	142.0	142.0	142.0	142.0	142.0
Rio Nogales 4	RIONOG_ST1	Guadalupe	Gas	South	2002	323.0	323.0	323.0	323.0	323.0	323.0
Sam Bertron 1	SRB_SRB_G1	Harris	Gas	Houston	1956	174.0	174.0	174.0	174.0	174.0	174.0
Sam Bertron 2	SRB_SRB_G2	Harris	Gas	Houston	1956	174.0	174.0	174.0	174.0	174.0	174.0
Sam Bertron 3	SRB_SRB_G3	Harris	Gas	Houston	1959	230.0	230.0	230.0	230.0	230.0	230.0
Sam Bertron 4	SRB_SRB_G4	Harris	Gas	Houston	1960	230.0	230.0	230.0	230.0	230.0	230.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
Sam Bertron T2	SRB_SRBGT_2	Harris	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0
San Jacinto SES 1	SJS_SJS_G1	Harris	Gas	Houston	1995	81.0	81.0	81.0	81.0	81.0	81.0
San Jacinto SES 2	SJS_SJS_G2	Harris	Gas	Houston	1995	81.0	81.0	81.0	81.0	81.0	81.0
San Miguel 1	SANMIGL_SANMIGG1	Atascosa	Coal	South	1982	391.0	391.0	391.0	391.0	391.0	391.0
Sandhill Energy Center 1	SANDHSYD_SH1	Travis	Gas	South	2001	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 2	SANDHSYD_SH2	Travis	Gas	South	2001	46.0	46.0	46.0	46.0	46.0	46.0
Sandhill Energy Center 3	SANDHSYD_SH3	Travis	Gas	South	2001	46.0	46.0	46.0	46.0	46.0	46.0
Sandhill Energy Center 4	SANDHSYD_SH4	Travis	Gas	South	2001	47.0	47.0	47.0	47.0	47.0	47.0
Sandhill Energy Center 5A	SANDHSYD_SH_5A	Travis	Gas	South	2004	155.0	155.0	155.0	155.0	155.0	155.0
Sandhill Energy Center 5C	SANDHSYD_SH_5C	Travis	Gas	South	2004	145.0	145.0	145.0	145.0	145.0	145.0
Sandhill Energy Center 6	SANDHSYD_SH6	Travis	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 7	SANDHSYD_SH7	Travis	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0
Sandow 5	SD5SES_UNIT5	Milam	Coal	South	2009	560.0	560.0	560.0	560.0	560.0	560.0
Silas Ray 10	SILASRAY_SILAS_10	Cameron	Gas	South	2004	48.0	48.0	48.0	48.0	48.0	48.0
Silas Ray 5	SILASRAY_SILAS_5	Cameron	Gas	South	1951	10.0	10.0	10.0	10.0	10.0	10.0
Silas Ray 6	SILASRAY_SILAS_6	Cameron	Gas	South	1950	20.0	20.0	20.0	20.0	20.0	20.0
Silas Ray 9	SILASRAY_SILAS_9	Cameron	Gas	South	1950	38.0	38.0	38.0	38.0	38.0	38.0
Sim Gideon 1	GIDEON_GIDEONG1	Bastrop	Gas	South	1965	137.0	137.0	137.0	137.0	137.0	137.0
Sim Gideon 2	GIDEON_GIDEONG2	Bastrop	Gas	South	1968	139.0	139.0	139.0	139.0	139.0	139.0
Sim Gideon 3	GIDEON_GIDEONG3	Bastrop	Gas	South	1972	335.0	335.0	335.0	335.0	335.0	335.0
Skyline Landfill Gas	DG_FERIS_4UNITS	Dallas	Other	North	2007	6.4	6.4	6.4	6.4	6.4	6.4
Small Hydro of Texas 1	CUECPL_UNIT1	Dewitt	Hydro	South	1992	1.0	1.0	1.0	1.0	1.0	1.0
South Texas 1	STP_STP_G1	Matagorda	Nuclear	Houston	1988	1362.0	1362.0	1362.0	1362.0	1362.0	1362.0
South Texas 2	STP_STP_G2	Matagorda	Nuclear	Houston	1989	1362.0	1362.0	1362.0	1362.0	1362.0	1362.0
Stryker Creek 1	SC2SES_UNIT1	Cherokee	Gas	North	1958	174.0	174.0	174.0	174.0	174.0	174.0
Stryker Creek 2	SCSES_UNIT2	Cherokee	Gas	North	1965	502.0	502.0	502.0	502.0	502.0	502.0
T H Wharton 3	THW_THWST_3	Harris	Gas	Houston	1974	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 31	THW_THWGT31	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 32	THW_THWGT32	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 33	THW_THWGT33	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 34	THW_THWGT34	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 4	THW_THWST_4	Harris	Gas	Houston	1974	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 41	THW_THWGT41	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 42	THW_THWGT42	Harris	Gas	Houston	1972	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 43	THW_THWGT43	Harris	Gas	Houston	1974	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 44	THW_THWGT44	Harris	Gas	Houston	1974	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 51	THW_THWGT51	Harris	Gas	Houston	1975	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 52	THW_THWGT52	Harris	Gas	Houston	1975	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 53	THW_THWGT53	Harris	Gas	Houston	1975	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 54	THW_THWGT54	Harris	Gas	Houston	1975	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 55	THW_THWGT55	Harris	Gas	Houston	1975	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 56	THW_THWGT56	Harris	Gas	Houston	1975	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton G1	THW_THWGT_1	Harris	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0
Tessman Road 1	DG_WALZE_4UNITS	Bexar	Biomass	South	2003	10.0	10.0	10.0	10.0	10.0	10.0
Texas City 1	TXCTY_CTA	Galveston	Gas	Houston	1987	100.0	100.0	100.0	100.0	100.0	100.0
Texas City 2	TXCTY_CTB	Galveston	Gas	Houston	1987	93.0	93.0	93.0	93.0	93.0	93.0
Texas City 3	TXCTY_CTC	Galveston	Gas	Houston	1987	93.0	93.0	93.0	93.0	93.0	93.0
Texas City 4	TXCTY_ST	Galveston	Gas	Houston	1987	128.0	128.0	128.0	128.0	128.0	128.0
Texas Gulf Sulphur	TGF_TGFGT_1	Wharton	Gas	Houston	1985	70.0	70.0	70.0	70.0	70.0	70.0
Thomas C Ferguson 1	FERGUS_FERGUSG1	Llano	Gas	South	1974	424.0	424.0	424.0	424.0	424.0	424.0
Tradinghouse 2	THSES_UNIT2	Mclennan	Gas	North	1972	787.0	0.0	0.0	0.0	0.0	0.0
Trinidad 6	TRSES_UNIT6	Henderson	Gas	North	1965	230.0	230.0	230.0	230.0	230.0	230.0
Trinity Oaks LFG	DG_KLBRG_1UNIT	Dallas	Biomass	North	2009	3.2	3.2	3.2	3.2	3.2	3.2
Twin Oaks 1	TNP_ONE_TNP_O_1	Robertson	Coal	North	1990	156.0	156.0	156.0	156.0	156.0	156.0
Twin Oaks 2	TNP_ONE_TNP_O_2	Robertson	Coal	North	1991	156.0	156.0	156.0	156.0	156.0	156.0
V H Braunig 1	BRAUNIG_VHB1	Bexar	Gas	South	1966	215.0	215.0	215.0	215.0	215.0	215.0
V H Braunig 2	BRAUNIG_VHB2	Bexar	Gas	South	1968	220.0	220.0	220.0	220.0	220.0	220.0
V H Braunig 3	BRAUNIG_VHB3	Bexar	Gas	South	1970	397.0	397.0	397.0	397.0	397.0	397.0
V H Braunig 5	BRAUNIG_VHB6CT5	Bexar	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0
V H Braunig 6	BRAUNIG_VHB6CT6	Bexar	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0
V H Braunig 7	BRAUNIG_VHB6CT7	Bexar	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0
V H Braunig 8	BRAUNIG_VHB6CT8	Bexar	Gas	South	2010	45.0	45.0	45.0	45.0	45.0	45.0
Valley 1	VLSES_UNIT1	Fannin	Gas	North	1962	174.0	0.0	0.0	0.0	0.0	0.0
Valley 2	VLSES_UNIT2	Fannin	Gas	North	1967	520.0	0.0	0.0	0.0	0.0	0.0
Valley 3	VLSES_UNIT3	Fannin	Gas	North	1971	375.0	0.0	0.0	0.0	0.0	0.0
Victoria Power Station 5	VICTORIA_VICTORG5	Victoria	Gas	South	2008	133.0	133.0	133.0	133.0	133.0	133.0
Victoria Power Station 6	VICTORIA_VICTORG6	Victoria	Gas	South	2008	164.0	164.0	164.0	164.0	164.0	164.0
W A Parish 1	WAP_WAP_G1	Ft. Bend	Gas	Houston	1958	174.0	174.0	174.0	174.0	174.0	174.0
W A Parish 2	WAP_WAP_G2	Ft. Bend	Gas	Houston	1958	174.0	174.0	174.0	174.0	174.0	174.0
W A Parish 3	WAP_WAP_G3	Ft. Bend	Gas	Houston	1961	278.0	278.0	278.0	278.0	278.0	278.0
W A Parish 4	WAP_WAP_G4	Ft. Bend	Gas	Houston	1968	552.0	552.0	552.0	552.0	552.0	552.0
W A Parish 5	WAP_WAP_G5	Ft. Bend	Coal	Houston	1977	645.0	645.0	645.0	645.0	645.0	645.0
W A Parish 6	WAP_WAP_G6	Ft. Bend	Coal	Houston	1978	650.0	650.0	650.0	650.0	650.0	650.0
W A Parish 7	WAP_WAP_G7	Ft. Bend	Coal	Houston	1980	565.0	565.0	565.0	565.0	565.0	565.0
W A Parish 8	WAP_WAP_G8	Ft. Bend	Coal	Houston	1982	600.0	600.0	600.0	600.0	600.0	600.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
W A Parish T1	WAP_WAPGT_1	Ft. Bend	Gas	Houston	1967	13.0	13.0	13.0	13.0	13.0	13.0
Whitney 1	WND_WHITNEY1	Bosque	Hydro	North	1953	15.0	15.0	15.0	15.0	15.0	15.0
Whitney 2	WND_WHITNEY2	Bosque	Hydro	North	1953	15.0	15.0	15.0	15.0	15.0	15.0
Wichita Falls 1	WFCOGEN_UNIT1	Wichita	Gas	West	1987	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 2	WFCOGEN_UNIT2	Wichita	Gas	West	1987	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 3	WFCOGEN_UNIT3	Wichita	Gas	West	1987	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 4	WFCOGEN_UNIT4	Wichita	Gas	West	1987	17.0	17.0	17.0	17.0	17.0	17.0
Winchester Power Park 1	WIPOPA_WPP_G1	Fayette	Gas	South	2009	45.0	45.0	45.0	45.0	45.0	45.0
Winchester Power Park 2	WIPOPA_WPP_G2	Fayette	Gas	South	2009	45.0	45.0	45.0	45.0	45.0	45.0
Winchester Power Park 3	WIPOPA_WPP_G3	Fayette	Gas	South	2009	45.0	45.0	45.0	45.0	45.0	45.0
Winchester Power Park 4	WIPOPA_WPP_G4	Fayette	Gas	South	2009	45.0	45.0	45.0	45.0	45.0	45.0
Wise-Tractebel Power Proj. 1	WCPP_CT1	Wise	Gas	North	2004	212.0	212.0	212.0	212.0	212.0	212.0
Wise-Tractebel Power Proj. 2	WCPP_CT2	Wise	Gas	North	2004	212.0	212.0	212.0	212.0	212.0	212.0
Wise-Tractebel Power Proj. 3	WCPP_ST1	Wise	Gas	North	2004	241.0	241.0	241.0	241.0	241.0	241.0
Wolf Hollow Power Proj. 1	WHCCS_CT1	Hood	Gas	North	2002	212.0	212.0	212.0	212.0	212.0	212.0
Wolf Hollow Power Proj. 2	WHCCS_CT2	Hood	Gas	North	2002	212.0	212.0	212.0	212.0	212.0	212.0
Wolf Hollow Power Proj. 3	WHCCS_STG	Hood	Gas	North	2002	280.0	280.0	280.0	280.0	280.0	280.0
Operational						**66,228**	**64,372**	**64,372**	**64,372**	**64,372**	**64,372**
						35.0	35.0	35.0	35.0	35.0	35.0
						0.0	0.0	0.0	0.0	0.0	0.0
						578.0	578.0	578.0	578.0	578.0	578.0
						74.0	74.0	74.0	74.0	74.0	74.0
						590.0	590.0	590.0	590.0	590.0	590.0
						300.0	300.0	300.0	300.0	300.0	300.0
						176.0	176.0	176.0	176.0	176.0	176.0
						18.0	18.0	18.0	18.0	18.0	18.0
						350.0	350.0	350.0	350.0	350.0	350.0
						10.0	10.0	10.0	10.0	10.0	10.0
						269.0	269.0	269.0	269.0	269.0	269.0
						0.0	0.0	0.0	0.0	0.0	0.0
						280.0	280.0	280.0	280.0	280.0	280.0
						6.0	6.0	6.0	6.0	6.0	6.0
						0.0	0.0	0.0	0.0	0.0	0.0
						0.0	0.0	0.0	0.0	0.0	0.0
						80.0	80.0	80.0	80.0	80.0	80.0
						56.0	56.0	56.0	56.0	56.0	56.0
						400.0	400.0	400.0	400.0	400.0	400.0
						0.0	0.0	0.0	0.0	0.0	0.0
						110.0	110.0	110.0	110.0	110.0	110.0
						35.0	35.0	35.0	35.0	35.0	35.0
						6.0	6.0	6.0	6.0	6.0	6.0
						485.0	485.0	485.0	485.0	485.0	485.0
						325.0	325.0	325.0	325.0	325.0	325.0
						573.0	573.0	573.0	573.0	573.0	573.0
						3.0	3.0	3.0	3.0	3.0	3.0
						28.0	28.0	28.0	28.0	28.0	28.0
						15.0	15.0	15.0	15.0	15.0	15.0
						1.0	1.0	1.0	1.0	1.0	1.0
Generation from Private Use Networks						**4,803.0**	**4,803.0**	**4,803.0**	**4,803.0**	**4,803.0**	**4,803.0**
Spencer 5	SPNCER_SPNCE_5	Denton	Gas	North	1973	61.0	0.0	0.0	0.0	0.0	0.0
Permian Basin 5	PB5SES_UNIT5	Ward	Gas	West	1959	112.0	0.0	0.0	0.0	0.0	0.0
Permian Basin 6	PBSES_UNIT6	Ward	Gas	West	1973	515.0	0.0	0.0	0.0	0.0	0.0
RMR						**688.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Eagle Pass	DC Tie	Maverick	Other	South		36.0	36.0	36.0	36.0	36.0	36.0
East	DC Tie	Fannin	Other	North		600.0	600.0	600.0	600.0	600.0	600.0
Laredo VFT	DC Tie	Webb	Other	South		100.0	100.0	100.0	100.0	100.0	100.0
North	DC Tie	Wilbarger	Other	West		220.0	220.0	220.0	220.0	220.0	220.0
Sharyland	DC Tie	Hidalgo	Other	South		150.0	150.0	150.0	150.0	150.0	150.0
DC-Ties						**1,106.0**	**1,106.0**	**1,106.0**	**1,106.0**	**1,106.0**	**1,106.0**
Kiamichi Energy Facility 1CT101	KMCHI_1CT101	Pittsburg	Gas	North	2003	142.0	142.0	142.0	142.0	142.0	142.0
Kiamichi Energy Facility 1CT201	KMCHI_1CT201	Pittsburg	Gas	North	2003	144.0	144.0	144.0	144.0	144.0	144.0
Kiamichi Energy Facility 1ST	KMCHI_1ST	Pittsburg	Gas	North	2003	310.0	310.0	310.0	310.0	310.0	310.0
Kiamichi Energy Facility 2CT101	KMCHI_2CT101	Pittsburg	Gas	North	2003	136.0	136.0	136.0	136.0	136.0	136.0
Kiamichi Energy Facility 2CT201	KMCHI_2CT201	Pittsburg	Gas	North	2003	138.0	138.0	138.0	138.0	138.0	138.0
Kiamichi Energy Facility 2ST	KMCHI_2ST	Pittsburg	Gas	North	2003	303.0	303.0	303.0	303.0	303.0	303.0
Tenaska-Frontier 1	FTR_FTR_G1	Grimes	Gas	North	2000	156.0	156.0	156.0	156.0	156.0	156.0
Tenaska-Frontier 2	FTR_FTR_G2	Grimes	Gas	North	2000	159.0	159.0	159.0	159.0	159.0	159.0
Tenaska-Frontier 3	FTR_FTR_G3	Grimes	Gas	North	2000	158.0	158.0	158.0	158.0	158.0	158.0
Tenaska-Frontier 4	FTR_FTR_G4	Grimes	Gas	North	2000	380.0	380.0	380.0	380.0	380.0	380.0
Tenaska-Gateway 1	TGCCS_CT1	Rusk	Gas	North	2001	149.0	149.0	149.0	149.0	149.0	149.0
Tenaska-Gateway 2	TGCCS_CT2	Rusk	Gas	North	2001	128.0	128.0	128.0	128.0	128.0	128.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
Tenaska-Gateway 3	TGCCS_CT3	Rusk	Gas	North	2001	146.0	146.0	146.0	146.0	146.0	146.0
Tenaska-Gateway 4	TGCCS_UNIT4	Rusk	Gas	North	2001	399.0	399.0	399.0	399.0	399.0	399.0
Switchable Resources						**2,848.0**	**2,848.0**	**2,848.0**	**2,848.0**	**2,848.0**	**2,848.0**
Barton Chapel Wind	BRTSW_BCW1	Jack	Wind	North	2007	120.0	120.0	120.0	120.0	120.0	120.0
Buffalo Gap Wind Farm 1	BUFF_GAP_UNIT1	Taylor	Wind	West	2006	120.0	120.0	120.0	120.0	120.0	120.0
Buffalo Gap Wind Farm 2	BUFF_GAP_UNIT2	Taylor	Wind	West	2006	233.0	233.0	233.0	233.0	233.0	233.0
Buffalo Gap Wind Farm 3	BUFF_GAP_UNIT3	Taylor	Wind	West	2007	150.0	150.0	150.0	150.0	150.0	150.0
Bull Creek Wind Plant	BULLCRK_WND1	Borden	Wind	West	2008	91.0	91.0	91.0	91.0	91.0	91.0
Bull Creek Wind Plant	BULLCRK_WND2	Borden	Wind	West	2008	89.0	89.0	89.0	89.0	89.0	89.0
Callahan Wind	CALLAHAN_WND1	Callahan	Wind	West	2004	114.0	114.0	114.0	114.0	114.0	114.0
Camp Springs 1	CSEC_CSECG1	Scurry	Wind	West	2004	130.0	130.0	130.0	130.0	130.0	130.0
Camp Springs 2	CSEC_CSECG2	Scurry	Wind	West	2007	120.0	120.0	120.0	120.0	120.0	120.0
Capricorn Ridge Wind 1	CAPRIDGE_CR1	Sterling	Wind	West	2007	200.0	200.0	200.0	200.0	200.0	200.0
Capricorn Ridge Wind 2	CAPRIDGE_CR3	Sterling	Wind	West	2007	186.0	186.0	186.0	186.0	186.0	186.0
Capricorn Ridge Wind 3	CAPRIDGE_CR2	Sterling	Wind	West	2008	140.0	140.0	140.0	140.0	140.0	140.0
Capricorn Ridge Wind 4	CAPRIDG4_CR4	Sterling	Wind	West	2007	115.0	115.0	115.0	115.0	115.0	115.0
Champion Wind Farm	TKWSW_CHAMPION	Nolan	Wind	West	2008	120.0	120.0	120.0	120.0	120.0	120.0
Delaware Mountain Wind Farm	DELAWARE_WIND_NWP	Culberson	Wind	West	2001	30.0	30.0	30.0	30.0	30.0	30.0
Desert Sky Wind Farm 1	INDNENR_INDNENR	Pecos	Wind	West	2001	25.0	25.0	25.0	25.0	25.0	25.0
Desert Sky Wind Farm 2	INDNENR_INDNENR_2	Pecos	Wind	West	2002	135.0	135.0	135.0	135.0	135.0	135.0
Elbow Creek Wind Project	ELB_ELBCREEK	Howard	Wind	West	2008	117.0	117.0	117.0	117.0	117.0	117.0
Forest Creek Wind Farm	MCDLD_FCW1	Glasscock	Wind	West	2008	124.0	124.0	124.0	124.0	124.0	124.0
Goat Wind	GOAT_GOATWIND	Sterling	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0
Green Mountain Energy 1	BRAZ_WND_WND1	Scurry	Wind	West	2008	99.0	99.0	99.0	99.0	99.0	99.0
Green Mountain Energy 2	BRAZ_WND_WND2	Scurry	Wind	West	2003	61.0	61.0	61.0	61.0	61.0	61.0
Gulf Wind I	TGW_T1	Kenedy	Wind	South	2003	143.0	143.0	143.0	143.0	143.0	143.0
Gulf Wind II	TGW_T2	Kenedy	Wind	South	2008	140.0	140.0	140.0	140.0	140.0	140.0
Hackberry Wind Farm	HWF_HWFG1	Shackelford	Wind	West	2008	165.0	165.0	165.0	165.0	165.0	165.0
Horse Hollow Wind 1	H_HOLLOW_WND1	Taylor	Wind	West	2008	210.0	210.0	210.0	210.0	210.0	210.0
Horse Hollow Wind 2	HHOLLOW4_WND1	Taylor	Wind	West	2005	115.0	115.0	115.0	115.0	115.0	115.0
Horse Hollow Wind 3	HHOLLOW3_WND_1	Taylor	Wind	West	2006	220.0	220.0	220.0	220.0	220.0	220.0
Horse Hollow Wind 4	HHOLLOW2_WIND1	Taylor	Wind	West	2006	180.0	180.0	180.0	180.0	180.0	180.0
Inadale Wind	INDL_INADALE1	Nolan	Wind	West	2006	197.0	197.0	197.0	197.0	197.0	197.0
Indian Mesa Wind Farm	INDNNWP_INDNNWP	Pecos	Wind	West	2008	80.0	80.0	80.0	80.0	80.0	80.0
King Mountain NE	KING_NE_KINGNE	Upton	Wind	West	2001	80.0	80.0	80.0	80.0	80.0	80.0
King Mountain NW	KING_NW_KINGNW	Upton	Wind	West	2001	80.0	80.0	80.0	80.0	80.0	80.0
King Mountain SE	KING_SE_KINGSE	Upton	Wind	West	2001	43.0	43.0	43.0	43.0	43.0	43.0
King Mountain SW	KING_SW_KINGSW	Upton	Wind	West	2001	80.0	80.0	80.0	80.0	80.0	80.0
Kunitz Wind	KUNITZ_WIND_LGE	Culberson	Wind	West	2001	35.0	35.0	35.0	35.0	35.0	35.0
Langford Wind Power	LGD_LANGFORD	Tom Green	Wind	West	2010	150.0	150.0	150.0	150.0	150.0	150.0
Loraine Windpark I	LONEWOLF_G1	Mitchell	Wind	West	2009	126.0	126.0	126.0	126.0	126.0	126.0
Loraine Windpark II	LONEWOLF_G2	Mitchell	Wind	West	2009	125.0	125.0	125.0	125.0	125.0	125.0
McAdoo Wind Farm	MWEC_G1	Dickens	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0
Mesquite Wind	LNCRK_G83	Shackelford	Wind	West	2006	200.0	200.0	200.0	200.0	200.0	200.0
Notrees-1	NWF_NWF1	Winkler	Wind	West	2008	153.0	153.0	153.0	153.0	153.0	153.0
Ocotillo Wind Farm	OWF_OWF	Howard	Wind	West	2008	59.0	59.0	59.0	59.0	59.0	59.0
Panther Creek 1	PC_NORTH_PANTHER1	Howard	Wind	West	2008	143.0	143.0	143.0	143.0	143.0	143.0
Panther Creek 2	PC_SOUTH_PANTHER2	Howard	Wind	West	2008	115.0	115.0	115.0	115.0	115.0	115.0
Panther Creek 3	PC_SOUTH_PANTHER3	Howard	Wind	West	2009	200.0	200.0	200.0	200.0	200.0	200.0
Papalote Creek Wind Farm	PAP1_PAP1	San Patricio	Wind	South	2010	180.0	180.0	180.0	180.0	180.0	180.0
Pecos Wind (Woodward 1)	WOODWRD1_WOODWRD1	Pecos	Wind	West	2008	80.0	80.0	80.0	80.0	80.0	80.0
Pecos Wind (Woodward 2)	WOODWRD2_WOODWRD2	Pecos	Wind	West	2001	80.0	80.0	80.0	80.0	80.0	80.0
Penascal Wind	PENA_UNIT1	Kenedy	Wind	South	2001	101.0	101.0	101.0	101.0	101.0	101.0
Penascal Wind	PENA_UNIT2	Kenedy	Wind	South	2008	101.0	101.0	101.0	101.0	101.0	101.0
Penascal Wind	PENA_UNIT3	Kenedy	Wind	South	2010	200.0	200.0	200.0	200.0	200.0	200.0
Post Oak Wind 1	LNCRK2_G871	Shackelford	Wind	West	2008	100.0	100.0	100.0	100.0	100.0	100.0
Post Oak Wind 2	LNCRK2_G872	Shackelford	Wind	West	2007	100.0	100.0	100.0	100.0	100.0	100.0
Pyron Wind Farm	PYR_PYRON1	Scurry	Wind	West	2007	249.0	249.0	249.0	249.0	249.0	249.0
Red Canyon	RDCANYON_RDCNY1	Borden	Wind	West	2008	84.0	84.0	84.0	84.0	84.0	84.0
Roscoe Wind Farm	TKWSW1_ROSCOE	Nolan	Wind	West	2006	200.0	200.0	200.0	200.0	200.0	200.0
Sand Bluff Wind Farm	MCDLD_SBW1	Glasscock	Wind	West	2008	90.0	90.0	90.0	90.0	90.0	90.0
Sherbino I	KEO_KEO_SM1	Pecos	Wind	West	2008	150.0	150.0	150.0	150.0	150.0	150.0
Silver Star	FLTCK_SSI	Eastland	Wind	North	2008	60.0	60.0	60.0	60.0	60.0	60.0
Snyder Wind Farm	ENAS_ENA1	Scurry	Wind	West	2007	63.0	63.0	63.0	63.0	63.0	63.0
South Trent Wind Farm	STWF_T1	Nolan	Wind	West	2007	98.0	98.0	98.0	98.0	98.0	98.0
Stanton Wind Energy	SWEC_G1	Martin	Wind	West	2008	120.0	120.0	120.0	120.0	120.0	120.0
Sweetwater Wind 1	SWEETWND_WND1	Nolan	Wind	West	2008	37.0	37.0	37.0	37.0	37.0	37.0
Sweetwater Wind 2	SWEETWN2_WND24	Nolan	Wind	West	2003	16.0	16.0	16.0	16.0	16.0	16.0
Sweetwater Wind 3	SWEETWN2_WND2	Nolan	Wind	West	2006	100.0	100.0	100.0	100.0	100.0	100.0
Sweetwater Wind 4	SWEETWN3_WND3	Nolan	Wind	West	2004	130.0	130.0	130.0	130.0	130.0	130.0
Sweetwater Wind 5	SWEETWN4_WND5	Nolan	Wind	West	2005	80.0	80.0	80.0	80.0	80.0	80.0
Sweetwater Wind 6	SWEETWN4_WND4B	Nolan	Wind	West	2007	105.0	105.0	105.0	105.0	105.0	105.0
Sweetwater Wind 7	SWEETWN4_WND4A	Nolan	Wind	West	2007	119.0	119.0	119.0	119.0	119.0	119.0
Texas Big Spring	SGMTN_SIGNALMT	Howard	Wind	West	1999	40.0	40.0	40.0	40.0	40.0	40.0

Unit Capacities - Summer

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Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
Trent Wind Farm	TRENT_TRENT	Nolan	Wind	West	1999	150.0	150.0	150.0	150.0	150.0	150.0
TSTC West Texas Wind	DG_ROSC2_1UNIT	Nolan	Wind	West	2008	2.0	2.0	2.0	2.0	2.0	2.0
Turkey Track Wind Energy Center	TTWEC_G1	Nolan	Wind	West	2008	170.0	170.0	170.0	170.0	170.0	170.0
West Texas Wind Energy	SW_MESA_SW_MESA	Upton	Wind	West	1999	70.0	70.0	70.0	70.0	70.0	70.0
Whirlwind Energy	WEC_WECG1	Floyd	Wind	West	1999	60.0	60.0	60.0	60.0	60.0	60.0
Wolfe Flats	DG_TURL_UNIT1	Hall	Wind	West	2007	10.0	10.0	10.0	10.0	10.0	10.0
Wolfe Ridge	WHTTAIL_WR1	Cooke	Wind	North	2008	113.0	113.0	113.0	113.0	113.0	113.0
WIND						**9,116**	**9,116**	**9,116**	**9,116**	**9,116**	**9,116**
Cedro Hill Wind	09INR0082	Webb	Wind	South		0.0	150.0	150.0	150.0	150.0	150.0
Papalote Creek Phase 2	08INR0012b	San Patricio	Wind	South		0.0	198.0	198.0	198.0	198.0	198.0
Senate Wind Project	08INR0011	Jack	Wind	North		0.0	0.0	150.0	150.0	150.0	150.0
Sherbino Mesa Wind Farm 2	06INR0012b	Pecos	Wind	West		0.0	0.0	0.0	150.0	150.0	150.0
Gunsight Mountain	08INR0018	Howard	Wind	West		0.0	0.0	0.0	120.0	120.0	120.0
Penascal Wind Farm	06INR0022c	Kenedy	Wind	South		0.0	0.0	0.0	202.0	202.0	202.0
Wild Horse Mountain	06INR0026	Howard	Wind	West		0.0	0.0	0.0	120.0	120.0	120.0
Cottonwood Wind	04INR0011c	Shackelford	Wind	West		0.0	0.0	0.0	0.0	100.0	100.0
Cedar Elm	04INR0011b	Shackelford	Wind	West		0.0	0.0	0.0	0.0	136.0	136.0
New Wind Generation						**0.0**	**348.0**	**498.0**	**1,090.0**	**1,326.0**	**1,326.0**
Lufkin	08INR0033	Angelina	Biomass	North		0.0	45.0	45.0	45.0	45.0	45.0
Nacogdoches Project	09INR0007	Nacogdoches	Biomass	North		0.0	0.0	100.0	100.0	100.0	100.0
CFB Power Plant Units 11&12	09INR0029	Calhoun	Coal	South		0.0	263.0	263.0	263.0	263.0	263.0
Sandy Creek 1	09INR0001	McLennan	Coal	North		0.0	0.0	925.0	925.0	925.0	925.0
TECO Central Plant	11INR0014	Harris	Gas	Houston		0.0	50.0	50.0	50.0	50.0	50.0
Panda Temple Power Ph 1	10INR0020	Bell	Gas-CC	North		0.0	0.0	0.0	650.0	650.0	650.0
Panda Temple Power Ph 2	10INR0021	Bell	Gas-CC	North		0.0	0.0	0.0	0.0	0.0	650.0
Coleto Creek Unit 2	14INR0002	Goliad	Coal	South		0.0	0.0	0.0	0.0	756.0	756.0
Jack County 2	10INR0010	Jack	Gas	North		0.0	620.0	620.0	620.0	620.0	620.0
New Units with Signed IA and Air Permit						**0.0**	**978.0**	**2,003.0**	**2,653.0**	**3,409.0**	**4,059.0**
Atkins 3	ATKINS_ATKINSG3	Brazos	Gas	North	1954	12.0	12.0	12.0	12.0	12.0	12.0
Atkins 4	ATKINS_ATKINSG4	Brazos	Gas	North	1958	22.0	22.0	22.0	22.0	22.0	22.0
Atkins 5	ATKINS_ATKINSG5	Brazos	Gas	North	1965	25.0	25.0	25.0	25.0	25.0	25.0
Atkins 6	ATKINS_ATKINSG6	Brazos	Gas	North	1969	50.0	50.0	50.0	50.0	50.0	50.0
C E Newman 5	NEWMAN_NEWMA_5	Dallas	Gas	North	1963	37.0	37.0	37.0	37.0	37.0	37.0
Spencer 4	SPNCER_SPNCE_4	Denton	Gas	North	1966	61.0	61.0	61.0	61.0	61.0	61.0
Collin 1	CNSES_UNIT1	Collin	Gas	North	1955	147.0	147.0	147.0	147.0	147.0	147.0
W B Tuttle 1	TUTTLE_WBT1G1	Bexar	Gas	South	1954	61.0	61.0	61.0	61.0	61.0	61.0
W B Tuttle 3	TUTTLE_WBT3G3	Bexar	Gas	South	1956	90.0	90.0	90.0	90.0	90.0	90.0
W B Tuttle 4	TUTTLE_WBT4G4	Bexar	Gas	South	1961	154.0	154.0	154.0	154.0	154.0	154.0
DeCordova 1	DC3SES_UNIT1	Hood	Gas	North	1975	816.0	816.0	816.0	816.0	816.0	816.0
Eagle Mountain 1	EMSES_UNIT1	Tarrant	Gas	North	1954	118.0	118.0	118.0	118.0	118.0	118.0
Eagle Mountain 2	EMSES_UNIT2	Tarrant	Gas	North	1956	100.0	100.0	100.0	100.0	100.0	100.0
Eagle Mountain 3	EMSES_UNIT3	Tarrant	Gas	North	1971	390.0	390.0	390.0	390.0	390.0	390.0
Valley 1	VLSES_UNIT1	Fannin	Gas	North	1962	0.0	174.0	174.0	174.0	174.0	174.0
Valley 2	VLSES_UNIT2	Fannin	Gas	North	1967	0.0	520.0	520.0	520.0	520.0	520.0
Valley 3	VLSES_UNIT3	Fannin	Gas	North	1971	0.0	375.0	375.0	375.0	375.0	375.0
Lake Creek 1	LCSES_UNIT1	Mclennan	Gas	North	1953	81.0	81.0	81.0	81.0	81.0	81.0
Lake Creek 2	LCSES_UNIT2	Mclennan	Gas	North	1959	239.0	239.0	239.0	239.0	239.0	239.0
Tradinghouse 2	THSES_UNIT2	Mclennan	Gas	North	1972	0.0	787.0	787.0	787.0	787.0	787.0
North Texas 1	NTX_NTX_1	Parker	Gas	North	1958	18.0	18.0	18.0	18.0	18.0	18.0
North Texas 2	NTX_NTX_2	Parker	Gas	North	1958	18.0	18.0	18.0	18.0	18.0	18.0
North Texas 3	NTX_NTX_3	Parker	Gas	North	1963	39.0	39.0	39.0	39.0	39.0	39.0
Spencer 5	SPNCER_SPNCE_5	Denton	Gas	North	1973	0.0	61.0	61.0	61.0	61.0	61.0
Permian Basin 5	PB5SES_UNIT5	Ward	Gas	West	1959	0.0	112.0	112.0	112.0	112.0	112.0
Permian Basin 6	PBSES_UNIT6	Ward	Gas	West	1973	0.0	515.0	515.0	515.0	515.0	515.0
Mothballed Resources						**2,478.0**	**5,022.0**	**5,022.0**	**5,022.0**	**5,022.0**	**5,022.0**
Pampa Energy Center	07INR0004	Gray	Steam-Coal			0.0	0.0	165.0	165.0	165.0	165.0
Comanche Peak 3 and 4	15INR0002	Somervel	Nuclear			0.0	0.0	0.0	0.0	0.0	3200.0
STP 3 and 4	15INR0008	Matagorda	Nuclear			0.0	0.0	0.0	0.0	0.0	2700.0
Potential Public Non-Wind Resources						**0.0**	**0.0**	**165.0**	**165.0**	**165.0**	**6065.0**
M Bar Wind	08INR0038	Andrews	Wind			0.0	0.0	194.0	194.0	194.0	194.0
Gulf Wind 3	05INR0015c	Kenedy	Wind			0.0	400.0	400.0	400.0	400.0	400.0
Gulf Wind 2	05INR0015b	Kenedy	Wind			0.0	400.0	400.0	400.0	400.0	400.0
Throckmorton Wind Farm	12INR0003	Throckmorton	Wind			0.0	400.0	400.0	400.0	400.0	400.0
Buffalo Gap 4 and 5	08INR0065	Nolan	Wind			0.0	465.0	465.0	465.0	465.0	465.0
Gatesville Wind Farm	09INR0034	Coryell	Wind			0.0	0.0	200.0	200.0	200.0	200.0
B&B Panhandle Wind	09INR0024	Carson	Wind			0.0	0.0	1001.0	1001.0	1001.0	1001.0
Scurry County Wind III	09INR0037	Scurry	Wind			0.0	0.0	350.0	350.0	350.0	350.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
Fort Concho Wind Farm	12INR0004	Tom Green	Wind			0.0	0.0	0.0	400.0	400.0	400.0
McAdoo Energy Center II	09INR0036	Dickens	Wind			0.0	0.0	0.0	500.0	500.0	500.0
Pistol Hill Energy Center	08INR0025	Ector	Wind			0.0	0.0	300.0	300.0	300.0	300.0
Potential Public Wind Resources						**-**	**1,665.0**	**3,710.0**	**4,610.0**	**4,610.0**	**4,610.0**
	10INR0011	Johnson	Gas			275.0	275.0	275.0	275.0	275.0	275.0
	10INR0069	Rusk	Coal			13.0	13.0	13.0	13.0	13.0	13.0
	09INR0081	Rusk	Coal			18.0	18.0	18.0	18.0	18.0	18.0
	10INR0029	Hood	Gas			810.0	810.0	810.0	810.0	810.0	810.0
	10INR0035	Harris	Gas			416.0	416.0	416.0	416.0	416.0	416.0
	10INR0012	Nacogdoches	Gas			300.0	300.0	300.0	300.0	300.0	300.0
	10INR0070	Hunt	Gas			0.0	50.0	50.0	50.0	50.0	50.0
	09INR0031	Ector	Gas			0.0	275.0	275.0	275.0	275.0	275.0
	10INR0032	Navarro	Gas			0.0	775.0	775.0	775.0	775.0	775.0
	10INR0080	Presidio	Solar			0.0	144.0	144.0	144.0	144.0	144.0
	11INR0037	Smith	Biomass			0.0	50.0	50.0	50.0	50.0	50.0
	11INR0028	Grimes	Gas			0.0	1280.0	1280.0	1280.0	1280.0	1280.0
	11INR0046	Brazoria	Gas			0.0	300.0	300.0	300.0	300.0	300.0
	11INR0048	Harris	Gas			0.0	300.0	300.0	300.0	300.0	300.0
	11INR0058	Pecos	Solar			0.0	135.0	135.0	135.0	135.0	135.0
	11INR0060	Tom Green	Solar			0.0	90.0	90.0	90.0	90.0	90.0
	11INR0061	Presidio	Solar			0.0	90.0	90.0	90.0	90.0	90.0
	09INR0050	Fannin	Gas			0.0	1200.0	1200.0	1200.0	1200.0	1200.0
	11INR0006	Lamar	Gas			0.0	579.0	579.0	579.0	579.0	579.0
	11INR0040	freestone	Gas			0.0	0.0	640.0	640.0	640.0	640.0
	10INR0021	Grayson	Gas			0.0	0.0	646.0	646.0	646.0	646.0
	10INR0018	Madison	Gas			0.0	0.0	550.0	550.0	550.0	550.0
	11INR0049	Wharton	Gas			0.0	0.0	275.0	275.0	275.0	275.0
	12INR0007	Lamar	Gas			0.0	0.0	296.0	296.0	296.0	296.0
	12INR0006	Limestone	Coal			0.0	0.0	875.0	875.0	875.0	875.0
	10INR0022	Harris	Gas			0.0	0.0	3500.0	3500.0	3500.0	3500.0
	12INR0016	Nueces	Other			0.0	0.0	0.0	1200.0	1200.0	1200.0
	14INR0003	Nolan	Coal			0.0	0.0	0.0	0.0	850.0	850.0
	14INR0005	Matagorda	Coal			0.0	0.0	0.0	0.0	1200.0	1200.0
Potential Confidential Non-Wind Resources						**1,832.0**	**7,100.0**	**13,882.0**	**15,082.0**	**17,132.0**	**17,132.0**
	10INR0048	Hardeman	Wind			1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
	09INR0069	Reagan	Wind			36.0	36.0	36.0	36.0	36.0	36.0
	09INR0070	Reagan	Wind			42.0	42.0	42.0	42.0	42.0	42.0
	10INR0016	Childress	Wind			150.0	150.0	150.0	150.0	150.0	150.0
	10INR0054	Palo Pinto	Wind			36.0	36.0	36.0	36.0	36.0	36.0
	10INR0062a	Pecos	Wind			49.5	49.5	49.5	49.5	49.5	49.5
	10INR0079	Nolan	Wind			60.0	60.0	60.0	60.0	60.0	60.0
	10INR0013	Upton	Wind			0.0	400.0	400.0	400.0	400.0	400.0
	10INR0052a	Knox	Wind			0.0	21.0	21.0	21.0	21.0	21.0
	10INR0057	Taylor	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	09INR0074	Motley	Wind			0.0	70.0	70.0	70.0	70.0	70.0
	10INR0015	Mitchell	Wind			0.0	350.0	350.0	350.0	350.0	350.0
	10INR0041	Floyd	Wind			0.0	135.0	135.0	135.0	135.0	135.0
	10INR0081a	Clay	Wind			0.0	30.4	30.4	30.4	30.4	30.4
	11INR0029	Throckmorton	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	09INR0054	Stonewall	Wind			0.0	148.5	148.5	148.5	148.5	148.5
	09INR0061	Kent	Wind			0.0	258.0	258.0	258.0	258.0	258.0
	07INR0013	Coke	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	07INR0015	Foard	Wind			0.0	180.0	180.0	180.0	180.0	180.0
	07INR0035	Tom Green	Wind			0.0	270.0	270.0	270.0	270.0	270.0
	08INR0061	Hardeman	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	08INR0062	Archer	Wind			0.0	249.0	249.0	249.0	249.0	249.0
	09INR0076	Jackson	Wind			0.0	300.0	300.0	300.0	300.0	300.0
	10INR0008	Pecos	Wind			0.0	500.0	500.0	500.0	500.0	500.0
	10INR0019	Deaf Smith	Wind			0.0	609.0	609.0	609.0	609.0	609.0
	10INR0033	Armstrong	Wind			0.0	399.0	399.0	399.0	399.0	399.0
	10INR0042	Mason	Wind			0.0	170.0	170.0	170.0	170.0	170.0
	10INR0051	Brazoria	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	10INR0056	Borden	Wind			0.0	249.0	249.0	249.0	249.0	249.0
	10INR0077	Callahan	Wind			0.0	101.0	101.0	101.0	101.0	101.0
	11INR0012	Duval	Wind			0.0	400.0	400.0	400.0	400.0	400.0
	10INR0060	Willacy	Wind			0.0	400.5	400.5	400.5	400.5	400.5
	11INR0050	Crosby	Wind			0.0	149.0	149.0	149.0	149.0	149.0
	10INR0009	Castro	Wind			0.0	300.0	300.0	300.0	300.0	300.0
	10INR0062b	Pecos	Wind			0.0	49.5	49.5	49.5	49.5	49.5
	11INR0062	Nueces	Wind			0.0	149.0	149.0	149.0	149.0	149.0
	11INR0033b	Cameron	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	11INR0033a	Cameron	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	08INR0020	Eastland	Wind			0.0	200.0	200.0	200.0	200.0	200.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	Year In-Service	2010	2011	2012	2013	2014	2015
	10INR0023	Haskell	Wind			0.0	386.0	386.0	386.0	386.0	386.0
	11INR0019	Upton	Wind			0.0	200.0	200.0	200.0	200.0	200.0
	11INR0054	San Patricio	Wind			0.0	161.0	161.0	161.0	161.0	161.0
	11INR0057	Cameron	Wind			0.0	165.0	165.0	165.0	165.0	165.0
	11INR0065	Nueces	Wind			0.0	240.0	240.0	240.0	240.0	240.0
	11INR0008a	Roberts	Wind			0.0	0.0	1000.0	1000.0	1000.0	1000.0
	11INR0047	Deaf Smith	Wind			0.0	0.0	600.0	600.0	600.0	600.0
	11INR0039	Starr	Wind			0.0	0.0	201.0	201.0	201.0	201.0
	07INR0014a	Wilbarger	Wind			0.0	0.0	140.0	140.0	140.0	140.0
	07INR0014b	Wilbarger	Wind			0.0	0.0	70.0	70.0	70.0	70.0
	10INR0081b	Clay	Wind			0.0	0.0	19.2	19.2	19.2	19.2
	06INR0022d	Kenedy	Wind			0.0	0.0	200.0	200.0	200.0	200.0
	09INR0075	Kinney	Wind			0.0	0.0	248.0	248.0	248.0	248.0
	11INR0005	Upton	Wind			0.0	0.0	500.0	500.0	500.0	500.0
	11INR0013	Mills	Wind			0.0	0.0	150.0	150.0	150.0	150.0
	11INR0025	Crockett	Wind			0.0	0.0	400.0	400.0	400.0	400.0
	11INR0043	Coke	Wind			0.0	0.0	300.0	300.0	300.0	300.0
	11INR0067	Cameron	Wind			0.0	0.0	78.0	78.0	78.0	78.0
	12INR0034	Borden	Wind			0.0	0.0	342.0	342.0	342.0	342.0
	09INR0048	Jack	Wind			0.0	0.0	150.0	150.0	150.0	150.0
	12INR0021	Edwards	Wind			0.0	0.0	165.0	165.0	165.0	165.0
	12INR0033	Motley	Wind			0.0	0.0	150.0	150.0	150.0	150.0
	10INR0062c	Pecos	Wind			0.0	0.0	201.0	201.0	201.0	201.0
	08INR0031	Childress	Wind			0.0	0.0	100.0	100.0	100.0	100.0
	12INR0002	Briscoe	Wind			0.0	0.0	0.0	750.0	750.0	750.0
	08INR0041	Coke	Wind			0.0	0.0	0.0	200.0	200.0	200.0
	12INR0026	Randall	Wind			0.0	0.0	0.0	400.0	400.0	400.0
	12INR0027	Gray	Wind			0.0	0.0	0.0	200.0	200.0	200.0
	08INR0019a	Gray	Wind			0.0	0.0	0.0	250.0	250.0	250.0
	08INR0019b	Gray	Wind			0.0	0.0	0.0	250.0	250.0	250.0
	08INR0019c	Gray	Wind			0.0	0.0	0.0	250.0	250.0	250.0
	08INR0044	Concho	Wind			0.0	0.0	0.0	200.0	200.0	200.0
	12INR0035	Nueces	Wind			0.0	0.0	0.0	249.0	249.0	249.0
	06INR0022f	Kenedy	Wind			0.0	0.0	0.0	200.0	200.0	200.0
	08INR0042	Coke	Wind			0.0	0.0	0.0	200.0	200.0	200.0
	08INR0054	Comanche	Wind			0.0	0.0	0.0	401.0	401.0	401.0
	08INR0056	Nolan	Wind			0.0	0.0	0.0	149.0	149.0	149.0
	09INR0025	Concho	Wind			0.0	0.0	0.0	180.0	180.0	180.0
	12INR0005	Floyd	Wind			0.0	0.0	0.0	1100.0	1100.0	1100.0
	12INR0018	Gray	Wind			0.0	0.0	0.0	600.0	600.0	600.0
	12INR0022	Hidalgo	Wind			0.0	0.0	0.0	200.0	200.0	200.0
	12INR0029	Swisher	Wind			0.0	0.0	0.0	500.0	500.0	500.0
	10INR0024	Briscoe	Wind			0.0	0.0	0.0	2940.0	2940.0	2940.0
	09INR0058	Howard	Wind			0.0	0.0	0.0	250.0	250.0	250.0
	09INR0051	Borden	Wind			0.0	0.0	0.0	249.0	249.0	249.0
	09INR0041	Mitchell	Wind			0.0	0.0	0.0	300.0	300.0	300.0
	13INR0004	Deaf Smith	Wind			0.0	0.0	0.0	0.0	500.0	500.0
	13INR0005	Carson	Wind			0.0	0.0	0.0	0.0	600.0	600.0
	13INR0006	Gray	Wind			0.0	0.0	0.0	0.0	750.0	750.0
	09INR0073	Scurry	Wind			0.0	0.0	0.0	0.0	200.0	200.0
	06INR0022e	Kenedy	Wind			0.0	0.0	0.0	0.0	200.0	200.0
	08INR0022	Floyd	Wind			0.0	0.0	0.0	0.0	100.0	100.0
	08INR0023	Floyd	Wind			0.0	0.0	0.0	0.0	100.0	100.0
	09INR0077	Reagan	Wind			0.0	0.0	0.0	0.0	500.0	500.0
	13INR0010	Parmer	Wind			0.0	0.0	0.0	0.0	1200.0	1200.0
	14INR0001	Pecos	Wind			0.0	0.0	0.0	0.0	0.0	500.0
Potential Confidential Wind Resources						**1,373.5**	**10,013.4**	**15,027.6**	**25,045.6**	**29,195.6**	**29,695.6**
Cobisa-Greenville	06INR0006	Hunt	Gas			0.0	0.0	0.0	1792.0	1792.0	1792.0
Excluded Resources						**0.0**	**0.0**	**0.0**	**1792.0**	**1792.0**	**1792.0**

Confidential

STP Attachment 9

ERCOT Protocols
Section 6: Ancillary Services

August 1, 2010

Where:

URC_{iz}	Uninstructed Resource Charge for that QSE per zone per Settlement Interval
ZUD_{izq}	Zonal Uninstructed Deviation for that QSE per zone per Settlement Interval
$MCPE_{iz}$	Market Clearing Price for Energy in that zone of that Settlement Interval
UF_i	Uninstructed Factor determined in accordance to deployed regulation

6.8.2 Capacity and Energy Payments for Out-of-Merit or Zonal OOME Service

6.8.2.1 Resource Category Generic Costs

To properly calculate Local Congestion costs, it is necessary to establish certain generic costs associated with Resources that will be used to calculate production costs incurred when the Resource(s) provides Out of Merit Order (OOM) or Zonal Out of Merit Energy (OOME) Service. These generic Resource costs include generic fuel costs and generic startup costs.

(1) Each ERCOT Generation Resource will be assigned to one of the following Resource Categories for the purpose of determining generic fuel costs:

Nuclear
Hydro
Coal and Lignite
Combined Cycle greater than 90 MW**
Combined Cycle less than or equal to 90 MW**
Gas-Steam Supercritical Boiler
Gas-Steam Reheat Boiler
Gas-Steam Non-reheat or boiler without air-preheater
Simple Cycle greater than 90 MW
Simple Cycle less than or equal to 90 MW
Diesel (and all other diesel or gas-fired Resources)
Renewable (i.e., non-Hydro renewable Resources)
Block Load Transfer (BLT)
DC Tie with non-ERCOT Control Area

** Determined by capacity of largest simple cycle combustion turbine in the train

The category of each Resource will be reported to ERCOT by the Generation Entity. Each Generation Entity shall ensure that each of its Resources is in the correct Resource category.

(2) The FIP shall be the Midpoint price, expressed in \$/MMBtu, published in Gas Daily, in the Daily Price Survey, under the heading "East-Houston-Katy, Houston Ship Channel" for the day of the Out of Merit Capacity (OOMC) or OOME deployment. The FIP for Saturdays, Sundays, holidays and other days for which there is no FIP published in Gas Daily, shall be the next published FIP after the day of the OOMC or OOME deployment.

In the event that the FIP is not published for more than two (2) days, the previous day published FIP will be used for Initial Settlement and the next day published FIP will be used for the Final Settlement Statement.

(3) Resource Category Generic Fuel Costs

Each ERCOT Generation Resource will be assigned a Resource Category Generic Fuel Cost (RCGFC) based on the Resource Category to which it is assigned. For Nuclear, Hydro, Coal and Lignite Resources, the RCGFC will be a fixed dollar/MWh amount as shown below. For the remaining Resource categories (except Renewable), the RCGFC will be the product of a heat rate (based on the heat rates used for the Capacity Auction) and a FIP. The RCGFC for Renewable Resources will be $0/MWh.

The RCGFC for each type of Resource for upward instructions will be:

Nuclear = $15.00/MWh
Hydro = $10.00/MWh
Coal and Lignite = $18.00/MWh
Combined Cycle greater than 90 MW** = FIP * 9 MMBtu/MWh
Combined Cycle less than or equal to 90 MW** = FIP * 10 MMBtu/MWh
Gas-Steam Supercritical Boiler = FIP * 10.5 MMBtu/MWh
Gas-Steam Reheat Boiler = FIP * 11.5 MMBtu/MWh
Gas-Steam Non-reheat or boiler without air-preheater = FIP * 14.5 MMBtu/MWh
Simple Cycle greater than 90 MW = FIP * 14 MMBtu/MWh
Simple Cycle less than or equal to 90 MW = FIP * 15 MMBtu/MWh
Diesel = FIP * 16 MMBtu/MWh
Block Load Transfer = FIP * 18 MMBtu/MWh
DC Tie with non-ERCOT Control Area = FIP * 18 MMBtu/MWh
Renewable = $0/MWh
LaaR = FIP * 18 MMBtu/MWh

** Determined by capacity of largest simple cycle combustion turbine in the train

The RCGFC for each type of Resource for downward instructions will be:

Nuclear = $0.00/MWh
Hydro = $0.00/MWh
Coal and Lignite = $3.00/MWh
Combined Cycle greater than 90 MW** = FIP * 5 MMBtu/MWh
Combined Cycle less than or equal to 90 MW** = FIP * 6.5 MMBtu/MWh
Gas-Steam Supercritical Boiler = FIP * 7.5 MMBtu/MWh
Gas-Steam Reheat Boiler = FIP * 9.5 MMBtu/MWh
Gas-Steam Non-reheat or boiler without air-preheater = FIP * 10.5 MMBtu/MWh
Simple Cycle greater than 90 MW = FIP * 10.5 MMBtu/MWh
Simple Cycle less than or equal to 90 MW = FIP * 12 MMBtu/MWh
Diesel = FIP * 12 MMBtu/MWh

Block Load Transfer = Not Applicable
DC Tie with non-ERCOT Control Area = Not Applicable
Renewable = $0/MWh

** Determined by capacity of largest simple cycle combustion turbine in the train

(4) Resource Category Generic Startup Costs

Resource Category Generic Startup Costs (RCGSC) represents the startup cost of capacity used for Replacement Reserve Service. The RCGSC for each type of Resource will be:

Nuclear = $0.00/MWh
Hydro = $0.00/MWh
Coal and Lignite = $0.00/MWh
Combined Cycle – when there are five hours or more between shutdown and startup for an OOMC instruction:
Combined Cycle greater than 90 MW** = $6,810 + (FIP * 2,200 MMBtu)
Combined Cycle less than or equal to 90 MW** = $5,310 + (FIP * 1,200 MMBtu)
Combined Cycle – when there are less than five (5) hours between shutdown and startup for an OOMC instruction:
Combined Cycle greater than 90 MW** = $6,810 + (FIP * 1,100 MMBtu)
Combined Cycle less than or equal to 90 MW** = $5,310 + (FIP * 600 MMBtu)
Gas-Steam Supercritical Boiler = $4,800 + (FIP * 16.5 MMBtu/MW * RMCu)
Gas-Steam Reheat Boiler = $3,000 + (FIP * 9.0 MMBtu/MW * RMCu)
Gas-Steam Non-reheat or boiler without air-preheater = $2,310 + (FIP * 2.30 MMBtu/MW * RMCu)
Simple Cycle greater than 90 MW = $5,000 + (FIP * 1.1 MMBtu/MW * RMCu)
Simple Cycle less than or equal to 90 MW = $2,300 + (FIP * 1.1 MMBtu/MW * RMCu)
Diesel = $487
Renewable = $0

Where:

RMC	Resource Maximum Capacity (in MW)
u	unit

** Determined by capacity of largest Simple Cycle combustion turbine in the train

(5) Resource Category Generic Minimum Energy Cost

Resource Category Generic Minimum Energy Cost (RCGMEC) is the heat rate of a unit, in one of these categories, at its LSL as set forth in the Resource Plan for that unit (as required by Section 4.4.15, QSE Resource Plans) when the Resource is selected to provide Out-of-Merit Service multiplied by the FIP as defined in Section 6.8.2.1, Resource Category Generic Costs, item (2). The RCGMEC for each type of Resource will be:

Nuclear Units = zonal MCPE for the units location
Hydro Units = zonal MCPE for the units location
Coal & Lignite Units = zonal MCPE for the units location
Combined Cycle greater than 90 MW** = 10 MMBtu/MWh * FIP
Combined Cycle less than or equal to 90 MW** = 10 MMBtu/MWh * FIP
Gas-Steam Supercritical Boiler = 16.5 MMBtu/MWh * FIP
Gas-Steam Reheat Boiler = 17.0 MMBtu/MWh * FIP
Gas-Steam Non-reheat or boiler without air-preheater = 19.0 MMBtu/MWh * FIP
Simple Cycle greater than 90 MW = 15.0 MMBtu/MWh * FIP
Simple Cycle less than or equal to 90 MW = 15.0 MMBtu/MWh * FIP
Diesel = 16.0 MMBtu/MWh * FIP

** Determined by capacity of largest simple cycle combustion turbine in the train

6.8.2.2 Capacity and Minimum Energy Payments

(1) OOMC Service may be used by ERCOT as a procured Replacement Reserve Resource in the Adjustment Period where necessary to support emergency operations and provide voltage support, stability, or to manage localized transmission limitations. All Generation Resources that are available as set forth in the Resource Plan and plan to be Off-line as set forth in the Resource Plan during the Settlement Interval for which Ancillary Services are being procured are eligible to be selected to provide OOMC Service. ERCOT shall not issue an OOME Up Dispatch Instruction for the energy associated with the LSL as set forth in the Resource Plan, or as specified for Quick Start Units in paragraph (7) below and paragraph (25) of Section 6.5.2, Balancing Energy Service, (as required by Section 4.4.15, QSE Resource Plans) for which it has issued an OOMC Dispatch Instruction. Zonal OOME Service will only be provided from Resources that are already On-line at the time of the Zonal OOME Dispatch Instruction and will not receive a capacity payment.

(2) The QSE for a Generation Resource that provides OOMC Service and produces less than 0.25 MWh of net metered generation for more than three (3) consecutive 15-minute Settlement Intervals within twenty-seven (27) 15-minute Settlement Intervals preceding the OOMC Dispatch Instruction is eligible for startup costs and Minimum Energy costs, and may be charged a clawback against startup costs unless the Generation Resource is a Quick Start Unit as defined in Section 2, Definitions and Acronyms. If the Generation Resource is a Quick Start Unit and it is Off-line at any time during at least one (1) 15-minute Settlement Interval within the four (4) 15-minute Settlement Intervals preceding the OOMC Dispatch Instruction, then it is eligible for startup costs and minimum energy costs and may be charged a clawback against startup costs.

(a) Startup costs are calculated as the RCGSC for starting the Generation Resource.

STP Attachment 10

ERCOT OPERATING GUIDES

Section 4: Emergency Operation

Notifications, Transmission Security, EEA and Black Start

July 1, 2010

4.5 Energy Emergency Alert (EEA)

REFERENCE: PROTOCOL SECTION 5.6.6.1, ENERGY EMERGENCY ALERT (EEA)

At times it may be necessary to reduce electrical Demand because of a temporary decrease in available electricity supply. To provide orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT will initiate and coordinate the implementation of the Energy Emergency Alert following the EEA levels set forth below in Section 5.6.7, EEA Levels.

The objective of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT Transmission Grid in order to reduce the chance of cascading outages.

ERCOT's operating procedures shall meet the following goals while continuing to respect the confidentiality of market sensitive data:

(1) Use of the market to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(2) Use of Responsive Reserve Services and other Ancillary Services to the extent permitted by ERCOT System conditions;

(3) Maximum use of ERCOT System capability;

(4) Maintenance of station service for nuclear Generation Resource Facilities;

(5) Securing of startup power for Generation Resources;

(6) Operation of power Generation Resources during loss of communication with ERCOT;

(7) Restoration of service to critical Loads in the manner defined in the Operating Guides; and

(8) Restoration of service to all customers following major system disturbances, giving priority to the larger groups of Customers.

ERCOT shall be responsible for coordinating with QSEs and TDSPs to monitor system conditions, initiating the EEA levels, notifying all QSEs, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

ERCOT, at management's discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

During the EEA, ERCOT has the authority to obtain energy from Direct Current (DC) Ties or Block Load Transfers (BLTs) from non-ERCOT Control Areas when capacity is available.

Some of the EEA levels will not be applicable if transmission security violations exist. There may be insufficient time to implement all levels in sequence, but to the extent practicable, ERCOT will use Ancillary Services which bidders have made available in the market to maintain or restore reliability.

ERCOT may immediately implement EEA Level 3 any time the steady-state system frequency is below 59.8 Hz and will immediately implement EEA Level 3 any time the steady-state frequency is below 59.5 Hz.

Percentages for EEA Level 3 Load shedding will be based on previous year's TDSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

REFERENCE: PROTOCOL SECTION 5.6.7, EEA LEVELS

EEA Level 1 — Maintain ERCOT Physical Responsive Capability (PRC) on Resources plus RRS MW provided from LaaR Equal to 2300 MW.

ERCOT will:

(1) Utilize available DC Tie capability that is not already being used by the market;

(2) Notify the Southwest Power Pool (SPP) Security Coordinator; and

(3) Issue Out of Merit Order (OOM) Dispatch Instructions to uncommitted units available within the expected timeframe of the emergency.

(4) Inquire about availability of BLTs.

QSEs will:

(1) Notify ERCOT of any Resources uncommitted but available in the timeframe of the emergency.

(2) Immediately update the HSL of any On-line Resource that is capable of providing extra capacity within thirty (30) minutes. The extra capacity must already be part of the QSE's Up Balancing bid curve in order for SPD to utilize the updated Resource Plan.

EEA Level 2A — Maintain ERCOT Physical Responsive Capability (PRC) on Resources plus RRS MW Provided from LaaR Equal to 1750 MW.

In addition to measures associated with EEA Level 1, ERCOT will:

(1) Instruct TDSPs to reduce Customers' Load by using distribution voltage reduction measures, if deemed beneficial by the TDSP;

(2) Instruct QSEs to deploy all Responsive Reserve, which is supplied from Load acting as a Resource (LaaR) (controlled by high-set under-frequency relays); and

(3) With the approval of the affected non-ERCOT Control Area, may instruct TDSPs to implement BLTs, which transfer load from the ERCOT Control Area to non-ERCOT Control Areas. Use of a BLT will be defined in the ERCOT Operating Guides.

EEA Level 2B – Maintain system frequency at 60 Hz:

Following deployment of the measures associated with EEA Level 1 and Level 2A, ERCOT will deploy all available Emergency Interruptible Load Service (EILS) Resources as a single block via a single Verbal Dispatch Instruction to all QSEs providing EILS.

Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation.

EEA Level 3 — Maintain system frequency at 59.8 Hz or greater

In addition to measures associated with EEA Levels 1, 2A and 2B, ERCOT will direct all TDSPs and their agents to shed firm Load, in one hundred (100) megawatt (MW) blocks, distributed as agreed and documented in the ERCOT Operation procedures in order to maintain a steady state system frequency of 59.8 Hertz (Hz). ERCOT may take this action prior to the expiration of the ten (10) minute EILS Resource deployment period if ERCOT, in its sole discretion, believes that shedding firm Load is necessary to maintain the stability of the ERCOT System. If, due to ERCOT System conditions, EILS Resources are not deployed prior to this action, ERCOT shall deploy EILS Resources as soon as possible following this action.

In addition to measures associated with EEA Levels 1, 2A and 2B, TDSPs will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TDSPs shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

REFERENCE: PROTOCOL SECTION 5.6.7.1, RESTORATION OF MARKET OPERATIONS

ERCOT shall continue the EEA until sufficient bids are received and deployed by ERCOT to eliminate the conditions requiring the EEA. ERCOT shall release EILS Resources after both the restoration of RRS capacity and initiation of the restoration of Loads acting as Resources.

Upon ERCOT notifying the market that the EEA is cancelled, each QSE that enabled extra capacity during Emergency Condition or EEA will remove the extra capacity from the Up Balancing bid stack and adjust the HSL of any online Resource within fifteen (15) minutes to a level that ensures compliance with all applicable standards.

REFERENCE: PROTOCOL SECTION 6.1.13, EMERGENCY INTERRUPTIBLE LOAD SERVICE (EILS)

Consistent with subsection (a) of P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service (EILS), EILS is defined as a special emergency service used during an Energy Emergency Alert (EEA) Level 2B or Level 3 to reduce Load and assist in maintaining or restoring ERCOT System frequency.

As provided by ERCOT to QSEs: *A special emergency service used by ERCOT in EEA Level 2B prior to ERCOT instructing Transmission and/or Distribution Service Providers (TDSPs) to shed firm Load, or in EEA Level 3 if deployment in EEA Level 2B was not possible.*

As provided by a QSE to ERCOT: *The provision of capacity by Load Resources capable of reducing their electricity consumption during EEA Level 2B or EEA Level 3.*

4.5.1 General

At times it may be necessary to reduce electrical Demand because of a temporary shortfall in available electricity supply. The reduction in supply could be caused by emergency outages of generators, transmission equipment, or other critical facilities; by short-term unavailability of fuel or generation; or by requirements or orders of government agencies. To provide an orderly, predetermined procedure for curtailing demand during such emergencies, ERCOT has established this Energy Emergency Alert (EEA).

The objective of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT Transmission Grid in order to reduce the chance of cascading outages.

4.5.2 Operating Procedures

The ERCOT System Operators have the authority to make and carry through decisions that are required to operate the ERCOT System during emergency or adverse conditions. ERCOT will have sufficiently detailed operating procedures for emergency or short supply situations and for restoration of service in the event of a partial or complete system shutdown. These procedures will be distributed to the personnel responsible for performing specified tasks to handle emergencies, remedy short supply situations, or restore service. TDSPs will develop procedures to be filed with ERCOT describing implementation of ERCOT requests in emergency and short supply situations, including interrupting Load, notifying others and restoration of service.

ERCOT and each TDSP will endeavor to maintain transmission ties intact if at all possible. This will: (1) permit rendering the maximum assistance to an area experiencing a deficiency in generation, (2) minimize the possibility of cascading loss to other parts of the system, and (3) assist in restoring operation to normal.

ERCOT's operating procedures will meet the following goals while continuing to respect the confidentiality of market sensitive data. If all goals cannot be respected simultaneously then the priority order listed below shall be respected:

1. Maintain station service for nuclear generating facilities.
2. Securing startup power for power generating plants.
3. Operating generating plants isolated from ERCOT without communication.
4. Restoration of service to critical Loads such as:
    - Military facilities
    - Facilities necessary to restore the electric utility system
    - Law enforcement organizations and facilities affecting public health
    - Communication facilities
5. Maximum utilization of ERCOT System Capability.

6. Utilization of Responsive Reserve Services and other Ancillary Services to the extent permitted by ERCOT System conditions.
7. Utilization of the market to the fullest extent practicable without jeopardizing the reliability of the ERCOT System.
8. Restoration of service to all Customers following major system disturbances, giving priority to the larger group of Customers.

4.5.3 Implementation

ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) and Transmission Operators (TOs), and coordinating the implementation of the EEA conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each ERCOT declared EEA level.

ERCOT has the authority to obtain emergency assistance energy over the Direct Current (DC) Tie(s) for use by ERCOT. ERCOT is also the coordinating authority for requests for emergency type power into or out of ERCOT.

ERCOT, at management's discretion, may at any time issue an appeal through the public news media for voluntary energy conservation.

There may be insufficient time to implement all levels in sequence. ERCOT can immediately implement EEA Level 3 any time the system frequency is below 59.8 Hz and will immediately implement EEA Level 3 any time the frequency is below 59.5 Hz.

Percentages for EEA Level 3 Load shedding will be based on the previous year's TDSP peak Load, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

The ERCOT System Operator shall declare the EEA levels to be taken by QSEs and TDSPs. QSEs and TDSPs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT Shift Supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

During EEA Level 3, ERCOT must be capable of shedding sufficient firm Load to arrest frequency decay and to prevent generator tripping. The amount of firm Load to be shed may vary depending on ERCOT grid conditions during the event. Each Transmission Service Provider (TSP) will be capable of shedding its allocation of firm Load, without delay. The maximum time for the TSP to interrupt firm Load will depend on how much Load is to be shed and whether the Load is to be interrupted by Supervisory Control and Data Acquisition (SCADA) or by the dispatch of personnel to substations. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. The following requirements apply for an ERCOT instruction to shed firm Load:

(a) Load interrupted by SCADA will be shed without delay and in a time period not to exceed thirty (30) minutes;

(b) Load interrupted by dispatch of personnel to substations to manually shed Load will be implemented within a time period not to exceed one (1) hour;

(c) The initial clock on the firm Load shed shall apply only to Load shed amounts up to 1000 MW total. Load shed amount requests exceeding 1000 MW on the initial clock may take longer to implement; and

(d) If, after the first Load shed instruction, ERCOT determines that an additional amount of firm Load should be shed, another clock will begin anew. The time frames mentioned above will apply.

Each TSP, or its Designated Agent, will provide ERCOT a status report of Load shed progress within thirty (30) minutes of the time of ERCOT's instruction or upon ERCOT's request.

4.5.3.1 General Procedures Prior to EEA Operations

Prior to declaring EEA Level 1 detailed in Section 4.5.3.3, EEA Levels, ERCOT shall:

- Start Reliability Must-Run (RMR) units available in the time frame of the emergency. RMR units should be loaded to full capability;
- Issue Dispatch Instructions to QSEs to suspend any ongoing ERCOT required generating unit testing;
- Utilize Non-Spin Reserve Services that can be deployed to increase Responsive Reserves;
- ERCOT shall use the Reserve Discount Factor (RDF) for the purpose of monitoring Physical Responsive Capability (PRC). The PRC will be used by ERCOT to determine the appropriate Emergency Notification and EEA levels; and
- In addition, ERCOT may issue an appeal through the public news media for voluntary Load reduction if authorized by the ERCOT Chief Executive Office or its designee based on an evaluation of existing and expected system conditions.

4.5.3.2 General Procedures During EEA Operations

ERCOT Control Area Authority will re-emphasize the following operational practices during EEA operations to minimize non-performance issues that may result from the pressures of the emergency situation.

OPERATOR	EEA ACTION
ERCOT	Suspends Ancillary Service Obligations that it deems to be contrary to reliability needs.
ERCOT	Notify each QSE and TO via hotline of declared EEA level.
QSEs and TOs	Notify each represented Market Participant of declared EEA level.
ERCOT, QSE & TDSP	Continue to respect confidential market sensitive data.
QSEs	Update Resource Plans to limit or remove capacity when unexpected start-up delays occur or when ramp limitations are encountered.
QSEs	Report when On-line or available capacity is at risk due to adverse circumstances.
QSEs and TDSPs and all	Must not suspend efforts toward expeditious compliance

OPERATOR	EEA ACTION
other Entities	with the applicable EEA levels declared by the ERCOT nor initiate any reversals of required actions without ERCOT authorization.
ERCOT	Define procedures for determining the proper redistribution of reserves during EEA operations.

4.5.3.3 EEA Levels

EEA Level 1 – Maintain ERCOT Physical Responsive Capability (PRC) on Resources plus RRS MW provided from LaaR Equal To 2300 Mw

OPERATOR	ACTION
ERCOT	o Utilize available DC Tie capability that is not already being used by the market. o Notify the Southwest Power Pool (SPP) Security Coordinator. o Issue Out of Merit Order (OOM) Dispatch Instructions to uncommitted units available within the expected timeframe of the emergency. o Inquire about availability of Block Load Transfers (BLTs).
QSE	o Notify ERCOT of any Resources uncommitted but available in the timeframe of the emergency. o Immediately update the High Sustainable Limit (HSL) of any On-line Resource that is capable of providing extra capacity within thirty (30) minutes. The extra capacity must already be part of the QSE's Up Balancing bid curve in order for Scheduling, Pricing and Dispatch (SPD) to utilize the updated Resource Plan.

EEA Level 2A – Maintain ERCOT Physical Responsive Capability (PRC) on Resources plus RRS MW Provided from LaaR Equal To 1750 MW

OPERATOR	ACTION
	In addition to measures associated with EEA Level 1.
ERCOT	o Instruct TDSPs to reduce Customers' Load by using distribution voltage reduction measures, if deemed beneficial by the TDSP. o Instruct QSEs to deploy all Responsive Reserve, which is supplied from Loads acting as a Resource (LaaRs) (controlled by high-set under-frequency

OPERATOR	ACTION
	relays). o With approval of the affected non-ERCOT Control Area, may instruct TDSPs to implement BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas.

EEA Level 2B - Maintain System Frequency At 60 Hz

OPERATOR	ACTION
	Following deployment of the measures under EEA Levels 1 and 2A.
ERCOT	o Deploy all available Emergency Interruptible Load Service (EILS) Resources as a single block via a single verbal Dispatch Instruction to all QSEs providing EILS. o Unless such a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation.

EEA Level 3 - Maintain System Frequency At 59.8 Hz Or Greater

OPERATOR	ACTION
	In addition to measures under EEA Levels 1, 2A and 2B.
ERCOT	Direct all TDSPs and their agents to shed firm Load, in one hundred (100) megawatt (MW) blocks, distributed as agreed and documented in the ERCOT operation procedures in order to maintain a steady state system frequency of 59.8 Hertz (Hz). ERCOT may take this action prior to the expiration of the ten (10) minute EILS Resource deployment period if ERCOT, in its sole discretion, believes that shedding firm Load is necessary to maintain the stability of the ERCOT System. If, due to ERCOT System conditions, EILS Resources are not deployed prior to this action, ERCOT shall deploy EILS Resources as soon as possible following this action.
	In addition to measures under EEA Levels 1, 2A and 2B.
TDSPs	Keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TDSPs shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

Obligation for Load shed is by Distribution Service Provider (DSP). Load shedding obligations need to be represented by an Entity with 7x24 operations and hotline communications with ERCOT and control over breakers. [Use Transmission Operators (TOs) as list of Entities.]

ERCOT Load Shed Table

Transmission Operator	2009 Total Transmission Operator Load (MW)
American Electric Power	9.33
Austin Energy	3.96
Brazos Electric Power Cooperative	4.62
CenterPoint Energy	26.56
City of Bryan	0.57
City of College Station	0.29
City of Denton	0.49
City of Garland	0.74
CPS Energy	7.34
Greenville Electric Utility Service	0.17
Lower Colorado River Authority	5.21
Magic Valley Electric Cooperative	0.65
Oncor	35.55
Public Utility Board of Brownsville	0.43
Rayburn Country Electric Cooperative	0.93
South Texas Electric Coop-Medina Electric Coop	0.67
Texas New Mexico Power	2.35
Tex-La	0.14
ERCOT Total	**100.00**

4.5.3.4 EEA Termination

ERCOT shall continue EEA until sufficient bids are received by ERCOT to eliminate the shortfall and restore adequate reserves.

OPERATOR	ACTION
ERCOT	Restore full reserve requirements (normally 2300 MW) Terminate the levels in reverse order, where practical. Notify each QSE and TO of EEA level termination.
QSEs and TOs	a. Implement actions to terminate previous actions as EEA levels are released in accordance with these guides. b. Notify represented Market Participants of EEA level changes. c. Report back to the ERCOT System Operator when each level is accomplished. d. Loads will be restored when specifically

OPERATOR	ACTION
	authorized by the ERCOT.

ERCOT shall maintain a stable ERCOT System frequency when restoring Load.

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
STP NUCLEAR OPERATING COMPANY	)	
	)	
(South Texas Project Units 3 and 4)	)	September 14, 2010
	)	

CERTIFICATE OF SERVICE

I hereby certify that on September 14, 2010 copies of "STP Nuclear Operating Company's Motion for Summary Disposition of Contention CL-2"; "Statement of Material Facts on Which No Genuine Issue Exists in Support of STP Nuclear Operating Company's Motion for Summary Disposition of Contention CL-2"; and "Joint Affidavit of Jeffrey L. Zimmerly and Adrian Pieniazek" were served by the Electronic Information Exchange on the following recipients:

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