ADDITIONAL INFORMATION

OPTIONS TO EVALUATE REQUESTS TO USE DISCOUNTED PARENT COMPANY GUARANTEES TO ASSURE FUNDING OF DECOMMISSIONING COSTS FOR POWER REACTORS

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REGULATORY HISTORY OF THE PARENT COMPANY GUARANTEE

On five occasions in the past, NRC used the rulemaking process to address use of the parent company guarantee (PCG) and the closely related self-guarantee.[1] NRC issued final rules in 1988,[2] 1993,[3] 1998,[4] 2002,[5] and 2011.[6] The NRC has never allowed, and no commenter has ever requested, discounts to the PCG or adding an earnings credit to the PCG in any rulemaking proceeding. The NRC determined that the cost of using the PCG, as well as all other decommissioning financial assurance (DFA) methods, was equitable:

> [T]he Commission believes that the rule is an equitable means of requiring reasonable assurance of funding for decommissioning without imposing an undue burden on licensees. [7]

Two themes recur throughout the regulatory history regarding the PCG method: (1) it was requested by licensees and permitted by NRC on the basis of its low cost and flexibility, and (2) it has always been subject to greater restrictions than other DFA methods to achieve an adequate degree of assurance that funds will be available when needed.

<u>1988 Decommissioning Rule</u>

In 1988, the NRC issued regulations that first established the requirement to provide DFA. The purpose of the amendments was to assure that decommissioning will be carried out with minimal impact on public and occupational health and safety and the environment. The NRC was particularly concerned with financial assurance:

> Inadequate or untimely consideration of decommissioning, specifically in the areas of planning and financial assurance, could result in significant adverse health, safety, and environmental impacts.[8]

Four methods of DFA were allowed for power reactors: prepayment; an external sinking fund which required annual deposits; a surety method or insurance; and, for government licensees, a statement of intent to obtain funds.[9] Power reactor DFA was unique in several ways. Only power reactors were: (1) required to certify that they would recalculate the amount of DFA annually to account for cost escalation; (2) allowed to build up their external sinking fund over time; (3) explicitly forbidden from providing financial assurance less than the prescribed amount; and (4) forbidden from using the PCG.

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[1] The self-guarantee has a more stringent financial test as compared to the PCG, but is substantially similar in other respects. *Compare* Appendix A To Part 30 - Parent Company Guarantees to Appendix C To Part 30 - Self Guarantees

[2] General Requirements for Decommissioning Nuclear Facilities, Final Rule, 53 FR 24018, July 27, 1988 [Hereinafter the 1988 Decommissioning Rule]

[3] Self-Guarantee as an Additional Financial Assurance Mechanism, Final Rule, December 29, 1993, 58 FR 68726 [Hereinafter the 1993 Self-Guarantee Rule]

[4] Financial Assurance Requirements for Decommissioning Nuclear Power Reactors, Final Rule, 63 FR 50465, September 22, 1998 [Hereinafter the 1998 Decommissioning Rule]

[5] Decommissioning Trust Provisions, Final Rule, Dec. 24, 2002, 67 FR 78332 [Hereinafter 2002 Decommissioning Trust Rule]

[6] Decommissioning Planning, Final Rule, June 17, 2011, 76 FR 35512 [Hereinafter 2011 Decommissioning Planning Rule]

[7] 1988 Decommissioning Rule, 53 FR 24018, 24038

[8] 1988 Decommissioning Rule, 53 FR 24018, 24019

[9] *See* 10 CFR 50.75(e)(3) [1998] At the time, all power reactors were electric utility licensees.

All licensees except research and test reactors (RTRs) are required to certify that they provided DFA in an amount required by the regulations. For each type of licensee, except RTRs, a minimum amount is defined, termed the "prescribed" amount. Materials licensees have the option to certify to a lower amount than the minimum prescribed amount, if they prepare an acceptable site-specific cost estimate that demonstrated they could decommissioning for a lower cost.[10]

However, power reactors are forbidden from certifying DFA in an amount less than the prescribed amount in § 50.75(c). The prohibition is written into the language of § 50.75(b)(1), which states that DFA must be "provided in an amount which may be more, but not less, than the amount stated in the table in paragraph (c)(1) of this section adjusted using a rate at least equal to that stated in paragraph (c)(2) of this section." The reason for the prohibition is that the prescribed amount is not expected to actually cover the cost of decommissioning. It is simply a reference amount, based on cost studies, which would provide the "bulk" of decommissioning costs.[11] The regulation states explicitly that the prescribed amount of paragraph (c) is not to be used by other agencies to establish rates.[12] In view of the expectation that the prescribed amount of § 50.75(c) will not cover the cost of decommissioning, a proposal to lower the amount of DFA provided by the licensee would be expected to increase the risk that decommissioning obligations will not be adequately funded.

During the rulemaking process, comments were received from all classes of licensees, except power reactors, supporting the use of the PCG. The NRC had not originally intended to allow the PCG for any class of licensee. The NRC stated that it did not include the financial test in the proposed rule because the PCG would not provide sufficient assurance of funds for decommissioning due to the potential for changing financial conditions and the lengthy time period before decommissioning would take place.[13] However, the NRC recognized that the financial test could be useful in some situations and could minimize impacts on the licensees.[14] The PCG was allowed for all classes of licensees, except power reactors. A number of restrictions were placed on its use: (1) the PCG was required to cover the entire cost of decommissioning;[15] (2) it was not allowed to be combined with any other method; (3) the guarantor had to pass a financial test, and (4) the test had to be repeated every year.

All licensees were allowed to combine the methods at their discretion, with the exception that the PCG could not be combined with other methods. This general authorization to combine methods was changed for power reactors in the 1998 Decommissioning Rule.

<u>1993 Self-Guarantee Rule</u>

In 1993, the NRC issued regulations to allow all licensees, except power reactors, to use the self-guarantee method as DFA.[16] The self-guarantee has a financial test substantially similar to

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[10] 1988 Decommissioning Rule 53 FR 24018, 24035
[11] Id. 53 FR 24030
[12] 10 CFR 50.75(a), "The requirements of this section, in particular paragraph (c) of this section, are in addition to, and not substitution for, other requirements, and are not intended to be used by themselves or by other agencies to establish rates."
[13] 1988 Decommissioning Rule 53 FR 24018, 24035
[14] Id.
[15] The entire cost requirement follows from the text of the PCG provisions in Appendix A to Part 30. It is also explained in footnote 2 in the 1998 Decommissioning Rule at 63 FR 50465, 50473
[16] 1993 Self-Guarantee Rule, 58 FR 68726

the PCG, but imposes higher tangible net worth and credit rating requirements.[17] In this rulemaking, power reactors commenters requested the NRC to extend the use of the self-guarantee to them. The Commission refused on grounds that the objective of the self-guarantee was to reduce the licensee's cost burden without causing adverse effects on public health and safety. The NRC already allowed power reactor licensees to accumulate decommissioning funds in an external sinking fund. Thus, electric utilities already were permitted a cost-reducing financial assurance mechanism.[18]

1998 Decommissioning Rule

In 1998, the NRC issued a rule to respond to the potential rate deregulation of the electric power generating industry.[19] The rulemaking was particularly relevant to the PCG issue, and provided several significant cost-reducing amendments for power reactors, as well as providing more flexibility in choosing DFA mechanisms. However, the 1998 Decommissioning Rule contains no mention of discounting or taking an earnings credit for the PCG.

The 1998 Decommissioning Rule significantly amended the 1988 rules for reactors by

(1) allowing an earnings credit for actual funds protected in a NDT,[20]
(2) removing the prohibition against power reactors using the PCG,[21]
(3) allowing the PCG to be used in combinations, [22]
(4) removing power reactor licensee discretion to combine DFA methods and requiring case-by-case evaluation of combinations and non-standard DFA mechanisms,
(4) restricting the use of the external sinking fund,
(5) eliminating the requirement to make annual deposits into the external sinking fund,
(6) relaxing the prepayment requirement,
(7) explicitly reserving the right to modify the schedule of accumulation of funds,
(8) adding additional DFA methods to increase the flexibility of the rule, and
(9) requiring a decommissioning fund status report.

A number of changes in 1998 Decommissioning Rule recognized that merchant plant licensees could be confronted with “quite large” shortfalls due to the loss of guaranteed revenues from ratepayers. By allowing an earnings credit on NDT funds held in the prepayment mechanism, merchant plant licensees were allowed to significantly reduce the up-front cost of providing DFA. Unlike materials licensees, who are required to place the entire amount needed into a prepaid account, merchant plant licensees could meet their requirement with just partial up-front payment. The difference between the actual amount in the prepaid NDT and the required amount of DFA could be made up by taking a credit for anticipated future earnings on the NDT funds. In the event the earnings credit was not adequate to meet the prescribed amount, then the PCG could be used as a supplement. Letters of credit and surety bonds could also be used as supplements, however, the NRC stated that PCGs and self-guarantees were less costly than other methods.[23] The authorization for reactors to use the PCG decreased the cost and increased the flexibility of the NRC’s DFA rules for power reactors.

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[17] *Compare* Appendix A To Part 30 - Criteria Relating to Use of Financial Tests and Parent Company Guarantees for Providing Reasonable Assurance Of Funds For Decommissioning to Appendix C To Part 30 - Criteria Relating To Use of Financial Tests and Self Guarantees for Providing Reasonable Assurance of Funds for Decommissioning
[18] 1993 Self-Guarantee Rule, 58 FR 68626, 68727
[19] 1998 Decommissioning Rule, 63 FR 50465
[20] Id. at 63 FR 50465
[21] Id. at 63 FR 50481
[22] Id. at 63 FR 50473
[23] Id. at 63 FR 50471

Commenters on the 1998 Decommissioning Rule generally endorsed parent company guarantees and self-guarantees as a reasonable method of assurance for power reactor licensees no longer meeting the definition of "electric utility."[24] Some commenters felt the financial test for the PCG would be burdensome. NRC responded that the financial test was based on a test developed by the US Environmental Protection Agency (EPA). The EPA test was used to assess the financial condition of firms managing hazardous waste that were seeking to assure closure and post-closure care obligations that were substantially smaller than typical decommissioning costs for power reactors. The NRC stated that the financial test was questionable when used for reactor licensees due the large decommissioning costs of reactors.[25] However, NRC did not amend the financial test before adopting it.

The flexibility of the PCG for reactor DFA use was greatly increased by allowing it to be used in combination with other methods. To accomplish that purpose, the previous requirement that the PCG must cover the entire cost of decommissioning was eliminated for reactors. That change allowed the PCG to be written for a portion, rather than the whole, of the DFA requirement, thus making it suitable for use in combinations. Along with changes to the PCG, the 1998 Decommissioning Rule eliminated the requirement for annual deposits into the NDT, which enhanced the usefulness of the PCG. However, the 1998 Decommissioning Rule identified three concerns for using a PCG or a self-guarantee for reactor DFA, particularly where they are used in combination with other methods:[26]

- Questionable applicability of the financial test
- Incentive to shift costs and avoid greater responsibility
- Incentive to delay or cease contributions to the NDT

To address those concerns, the Commission required case-by-case evaluations of combinations of methods, particularly those with the PCG, and other non-standard methods. The need for the requirement is explained in the Supplementary Information of the 1998 Rule:

> Although the external sinking fund, standing alone, is not allowed for the licensees losing such regulatory oversight, the NRC framework also offers opportunities for case-by-case consideration of non-standard financial assurance arrangements. Examples include § 50.75(e)(1)[(vi)], which allows unspecified, other guarantee methods; and certain contractual arrangements in § 50.75(e)(1)[(v)].[27]
>
> In addition, the applicability of the NRC's parent company guarantees and self-guarantees to power reactor licensees is questionable … because the underlying financial tests were developed primarily for other types of entities assuring smaller decommissioning obligations. Consequently, a case-by-case approach, through which reactor licensees that lose the ability to recover decommissioning costs through regulated rates or other mandatory charges established by a regulatory body, could provide assurance equivalent to the other methods that the NRC is allowing. However, the NRC will need to ensure that the mechanisms used will, in fact, provide adequate

[24] Id. at 63 FR 50470
[25] Id. at 63 FR 50473, referring to 50470
[26] 1998 Decommissioning Rule, 63 FR 50465, 50473
[27] 1998 Decommissioning Rule at 63 FR 50469. Typographical errors in the 1998 Decommissioning Rule *Federal Register* Notice were corrected in 63 FR 57236. The text shown uses the corrected citations to the requirements.

> financial assurance.[28]
>
> Because of the low costs of guarantees, however, allowing this combination of mechanisms could create an incentive for licensees to delay or cease payments into the sinking fund and, instead, to rely on the guarantee for as much of the cost as possible. Given the magnitude of typical decommissioning costs for reactors, this possibility could hinder the timely conduct of decommissioning. In other words, decommissioning could be significantly delayed if, because of a licensee's inadequate contributions to its sinking fund, a guarantor had to come up with large amounts of money at the time of decommissioning.[29]
>
> In sum, the NRC has eliminated the prohibition on combining parent company or self-guarantees with external sinking funds. The NRC will also consider other combinations of mechanisms on a case-by-case basis when the aforementioned concerns are addressed.[30]

Before 1998 Decommissioning Rule was issued, substituting the low-cost, non-cash PCG for deposits into the NDT was not possible. However, the 1998 Decommissioning rule eliminated the requirement to make annual deposits in the NDT, and permitted the PCG to be combined with a NDT. However, the NRC did not change the requirement to have the funds available for decommissioning at the time termination of operations was expected.[31] The Commission explained the need for requiring all funds to be available at the time termination of operations was expected in an earlier rulemaking:

> This requirement was imposed to avoid a situation where lack of funds could delay and degrade the decommissioning process to the detriment of public health and safety. Although the dismantlement process can be completed in discrete stages, the potential unavailability of funds at a later stage may conceivably affect the dismantlement process at an earlier stage by creating incentives to "cut corners."[32]

To assure achievement of the funding requirement in view of the incentives to delay or cease contributions into the NDTs, and the incentive to shift costs, the NRC required a case-by-case evaluation for any combination of methods and non-standard methods of providing DFA to verify that they provided an equivalent degree of assurance as compared to the methods described in § 50.75(e)(1)(i) through (v) under the specific circumstances of the licensee's submittal.

Interestingly, in response to the 1998 Decommissioning Rule, NEI proposed a framework for DFA that would have extended use of the external sinking fund to a larger number of merchant plant licensees than the regulations would allow, without a requirement for case-by-case evaluation for equivalency of DFA. The NRC declined the proposal on grounds that it would increase the risk of inadequate decommissioning funding. The response to Comment 8 discusses the reasons the external sinking fund is subject to greater oversight when used by a merchant plant licensee.[33]

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[28] Id.at 63 FR 50473
[29] Id.
[30] Id.
[31] § 50.75(e)(1)(i) and (ii)
[32] Decommissioning Funding for Prematurely Shutdown Power Reactors, Final Rule, 57 FR 30383, 30385
[33] Id. at 63 FR 50469

To summarize, the 1998 Decommissioning Rule significantly amended the rules for reactors. They gained several cost-reducing methods and greater flexibility in choosing financial assurance methods. NRC considered and rejected a comment to allow the use of the external sinking fund for merchant plant licensees without case-by-case evaluation for equivalency of DFA. However, although benefitting from the changes made in allowable financial assurance methods, reactor licensees lost the discretion to combine methods at will. The need to restrict licensee discretion arose from concern for the adequacy of reactor DFA in view of the economic deregulation of the industry. The concerns followed two general themes. First, concerns were expressed regarding the potential effects of increased competition on merchant plants. Second, the expanded use for the PCG raised concerns. The Commission expressed the two themes in the following statement:

> Making riskier financial assurance mechanisms available to riskier licensees compounds risk to the public that adequate funds will not be available when needed. Thus, prudent public policy may limit the range of mechanisms that should be offered to certain categories of licensees.[34]

In recognition of the greater risks, NRC codified a number of measures that worked together to limit the risk to the public and provide NRC with greater oversight authority. The decommissioning fund status report was imposed to allow NRC to monitor performance.[35] The NRC extended its monitoring authority to allow a review the licensee's performance at any time.[36] To address cases where monitoring revealed that the licensee had not provided adequate financial assurance, the NRC reserved the right to modify the schedule of accumulation of funds, either in cooperation with the rate making authority or on its own.[37] The elimination of licensee discretion to combine methods at will ensured that the degree of assurance would not be allowed to decrease below the levels established in the rules.[38]

<u>2002 Decommissioning Trust Rule</u>

In 2002, NRC issued a rule that required merchant plant licensees to revise their NDT agreements to increase the assurance that adequate funds will be available when needed for decommissioning.[39] The rulemaking included a draft revision to RG 1.159 which, among other items, made changes to the PCG agreement.[40] The changes to the PCG agreement were made to conform to the 1998 Decommissioning Rule that allowed the PCG to be issued as partial satisfaction of the decommissioning financial assurance (DFA) requirement, when combined with another method. In particular, the PCG amount could be less than the total decommissioning cost.[41] However, the NRC did not allow, and no commenter requested, discounting the PCG or adding an earnings credit to it.

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[34] 1998 Decommissioning Rule, 63 FR 50465, 50468
[35] § 50.75(f)(1)
[36] § 50.75(e)(2)
[37] § 50.75(e)(2)
[38] § 50.75(e)(1)(vi)
[39] 2001 Decommissioning Trust Rule, 67 FR 78332
[40] Id. 67 FR 78332 - 33
[41] RG 1.159, Rev. 1, "Assuring The Availability of Funds for Decommissioning Nuclear Reactors," p. 1.159-57 October 2003

2011 Decommissioning Planning Rule

In 2011, NRC issued the Decommissioning Planning Rule which, among other things, amended the financial test of the PCG and self-guarantee.[42] The proposed rule was issued in 2008 requesting comments on, among other items, changes to the PCG financial test.[43] The time period of the rulemaking proceeding overlapped with the time period of the power reactor industry's efforts to obtain discounts for the PCG. However, no licensee or industry representative requested NRC to add an earnings credit to the PCG, or to allow discounts when using a PCG, or stated that the cost of the PCG was unduly burdensome to the industry.

Two changes were made to the financial test of the PCG. The minimum amount of tangible net worth was raised from $10 million to $21 million to account for inflation. More significantly, licensees were allowed to use intangible assets to meet a total net worth ratio. This contrasted with the previous test, which excluded intangible assets, and based the ratio on tangible net worth only. This change significantly increases the amount of PCGs a parent company can issue. To the extent that the financial test has some effect on the licensee or its parent company, the 2011 rule provides significant relief.

One of the goals of the 2011 rule was to change the financial assurance rules in 10 CFR Parts 30, 40, 70, and 72 to achieve greater consistency with 10 CFR Part 50 regulations.[44] To meet that goal, NRC revised the PCG rules to provide materials licensees opting to use the external sinking fund with the same degree of flexibility that power reactor licensees have had since 1998 (in a final rulemaking for power reactor financial assurance, the NRC allowed use of a parent company guarantee in combination with an external sinking fund.)[45] In the development of the technical basis for the revision, the NRC found no provisions to allow either discounting or taking an earnings credit for the PCG. As a result, there was no need to revise NUREG-1757, Vol.15, which states that no credit is taken for earnings on any financial assurance mechanism (e.g., a parent company guarantee) that does not set aside actual funds as prepayment.[46]

Summary of Regulatory History

In summary, the PCG was authorized as a DFA method in order to reduce cost and increase flexibility for the licensees. The regulatory history shows a complete absence of any intention or permission to discount the PCG or add an earnings credit to the PCG. In the course of 23 years of rulemaking on the subject, no commenter requested discounts or earnings credits for the PCG. However, the NRC identified a number of adverse incentives the PCG provided to reactor licensees as a result of the permission to combine the PCG with other methods. To mitigate those incentives, and in contrast to all other classes of licensees, the NRC created a case-by-case process to evaluate requests from reactor licensees to combine methods or use non-standard methods of DFA. In order to obtain NRC approval for a discounted PCG, the licensee must demonstrate that the specific circumstances of its submittal provides assurance equivalent to the existing methods specified in § 50.75(e)(1)(i) through (v).

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[42] 2011 Decommissioning Planning Rule, 76 FR 35512, 35524
[43] Decommissioning Planning, Proposed Rule, January 22, 2008, 73 FR 3812
[44] 2011 Decommissioning Planning Rule, 76 FR 35512, 35517
[45] Id.
[46] Consolidated NMSS Decommissioning Guidance Financial Assurance, Recordkeeping, and Timeliness NUREG-1757, Vol. 15, Section 4.3.2.10, September 2003

The financial test for the PCG was revised in 2011 to allow intangible assets to be used to meet a total net worth test for the PCG. The change significantly increases the amount of PCGs a parent company can issue.

NEI'S DISCOUNTING PROPOSAL COMPARED TO 10 CFR 50.75

NEI proposed that power reactor licensees should be allowed to use a discounted PCG to meet the requirements for DFA. The amount of the discounted PCG would be calculated using the net present value (NPV) approach.[47] NEI stated that the discounted PCG would be combined with the licensee's commitment to make annual adjustments to the discounted PCG.[48] The following discussion recites the evolution of the proposal since it was first introduced in September 2009. The discussion then considers whether the request may be granted without approval under the equivalency test of § 50.75(e)(1)(vi). It concludes that the proposed method must be approved by NRC under the equivalency test.

NEI's first request, in its September 2009 letter, was to revise the NRC's regulatory guidance to allow licensees to discount the DFA requirement using the NPV approach without NRC approval.[49] The September 2009 letter referred to the "current value," which was defined as the amount that would be necessary to put in a fund today to assure full decommissioning funding at the time of plant shutdown. NEI later clarified that it was requesting an NPV discount.[50] In August 2010, NEI stated that the NPV approach should be used to allow discounts to the PCG, in combination with an annual readjustment of the amount needed to cover the gap between the prepaid funds and the amount of DFA required.[51] NEI stated the combination was equivalent to cash held in a NDT.[52]

NEI stated in its March 2011 letter that the licensee is not required to obtain approval under the equivalency test provisions of § 50.75(e)(1)(vi) when it takes a discount on the DFA requirement.[53] The March 2011 letter stated that § 50.75(e)(1)(iii)(B) allowed discounting the PCG and no approval was required.[54] However, in its final comments submitted in the July 2011 letter, NEI agreed that all combinations of methods, save one, are subject to the equivalency test of § 50.75(e)(1)(vi).[55] The stated exception is a combination of an external sinking fund, a discounted PCG, and the licensee's commitment to adjust the PCG amount annually to account for changes in decommissioning costs (hereinafter called the "sinking fund discount combination").[56] NEI stated that the sinking fund discount combination should equal the total amount of funds estimated to be necessary for decommissioning, with the understanding that the total amount would be reduced by a discount calculated using an NPV approach. Details of NEI's reasoning for distinguishing the sinking fund discount combination

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[47] NEI, SECY-10-0084: Explanation of Changes to Revision 2 to Regulatory Guide 1.159, p.7, August 4, 2010, (ML103220332) [Hereinafter NEI August 2010 letter]
[48] NEI, Industry Comments on June 8 Workshop, p.10, July 13, 2011 (ML11196A203) [Hereinafter NEI July 2011 letter]
[49] NEI, Industry comments on NRC's Draft Regulatory Guide DG-1229, Enclosure 1, Revision 1, p.10-12, September 10, 2009 (ML092590128) [Hereinafter NEI September 2009 letter]
[50] NEI August 2010 letter at 7
[51] NEI August 2010 letter at 7-8
[52] NEI August 2010 letter at 8
[53] NEI, Concerns Regarding the Conduct of the US Nuclear Regulatory Commission's March 2 Decommissioning Funding Workshop. p.1, March 8, 2011 (ML11069016) [Hereinafter NEI March 2011 letter]
[54] Id.
[55] NEI, Industry Comments on June 8 Workshop, p.10, July 13, 2011 (ML11196A203)
[56] Id. at 9

as an exception to the equivalency test are discussed in the response to Comment 8.

In earlier comments, NEI offered two examples to illustrate its discounting proposal. In its first example, NEI referred to the three license transfer orders as precedents for approving discounted PCGS.[57] The three license transfer orders used a combination of a discounted PCG, a prepaid account, and a condition to annually adjust the discounted amount. The second example was a hypothetical new reactor application, where the proposed combination was a discounted PCG and a commitment to annually adjust the amount. The DFA requirement and NEI's proposed discounted PCG amount the Millstone license transfer order and a new reactor are shown below.

Millstone license transfer[58]	Shortfall from § 50.75 requirement	$77 million
	Discounted PCG amount	$26 million
New reactor example[59]	§ 50.75 requirement	$405 million
	Discounted PCG amount	$171 million

NEI stated that it was not proposing to use a discounted PCG standing alone:

> [W]e're not saying that we are relying somehow on the static parent company guarantee to magically grow. I agree with you, that wouldn't make any sense, but we are updating it annually ….[60]

In both examples, NEI proposed that a discounted PCG, if it used, would be combined with a commitment by the licensee to adjust the discounted amount annually. In the Millstone license transfer, the discounted PCG was combined with a commitment to make annual adjustments and a prepaid account. In the new reactor example, the discounted PCG would be combined only with a commitment to make annual adjustments.

Now recall that NEI's July 2011 letter agreed that all combinations, except the external sinking fund and a PCG, require NRC approval under the equivalency test. Neither of the examples shown above falls within the exception NEI would carve out from the requirement for evaluation and approval pursuant to the equivalency test of § 50.75(e)(1)(vi).

However, the regulatory structure does not allow any combination of methods to be used by a reactor licensee without approval by the NRC on the basis of the equivalency test of § 50.75(e)(1)(vi). The equivalency test applies to the combination of an external sinking fund and a PCG, as well as all other combinations. The applicable regulatory requirements are stated below:

> § 50.75 (b) Each power reactor …
> (1) … [must certify] that financial assurance for decommissioning will be (for a license applicant), or has been (for a license holder), provided in an amount which may be more, but not less, than the amount stated in the table in

[57] NEI September 2009 letter at 11 (ML092590128)
[58] *See* response to Comment 2, enclosed, for calculation of shortfall and discounted PCG amount.
[59] NEI, SECY-10-0084: Explanation of Changes to Revision 2 to Regulatory Guide 1.159, p.9, August 4, 2010 (ML103220332)
[60] Transcript, Decommissioning Funding Workshop, Common Sessions, statement of Ms. Kass (NEI), March 2, 2011, p.111 (ML110810747)

> paragraph (c)(1) of this section adjusted using a rate at least equal to that stated in paragraph (c)(2) of this section.
> …
> (3) The amount must be covered by one or more of the methods described in paragraph (e) of this section as acceptable to the NRC.
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> § 50.75(e)(1)(vi) Any other mechanism, or combination of mechanisms, that provides, *as determined by the NRC upon its evaluation of* the specific circumstances of each licensee submittal, *assurance of decommissioning funding equivalent to that provided by the mechanisms specified in paragraphs (e)(1)(i) through (v) of this section*. Licensees who do not have sources of funding described in paragraph (e)(1)(ii) of this section may use an external sinking fund in combination with a guarantee mechanism, as specified in paragraph (e)(1)(iii) of this section, provided that the total amount of funds estimated to be necessary for decommissioning is assured. [Emphasis added]

NEI's proposal, even in the limited form of the sinking fund discount combination, does not meet the requirements of 10 CFR 50.75(b)(1), (b)(3), or (e)(1)(vi). It does not meet (b)(1) because it is less than the minimum prescribed amount of § 50.75(c).[61] It does not meet (b)(3) because the combination of the discounted PCG with a commitment to make annual adjustments is not specifically described in § 50.75(e)(1)(i) - (v). It does not meet § 50.75(e)(1)(vi) because it eliminates NRC approval and evaluation for equivalency on a case-by-case basis.

However, NEI's proposal may be considered under § 50.75(e)(1)(vi). The proper application of the regulation was the subject of a Commission Memorandum and Order. In the 2001 license transfer of Fitzpatrick and Indian Point Unit 3 from the Power Authority of the State of New York (PASNY) to Entergy Nuclear Operations (PASNY transfer order) the Commission explained that § 50.75(e)(1)(vi) provides a process for the licensee to request approval of methods not otherwise allowed in the regulations:

> [It is] the Commission's intention to at least consider, on a case-by-case basis, funding assurance mechanisms not expressly permitted under subsections [§ 50.75(e)(1)](i) through (v). In promulgating subsection [§ 50.75(e)(1)](vi), we intended to give applicants the flexibility necessary to structure methods outside the parameters of any one of the five methods set forth in subsections (i) through (v) or to combine portions of those subsections in such a way as to provide the same end-result of funding assurance.[62]

The Commission emphasized in the PASNY transfer order that reactor licensees must meet the equivalency test when they propose a combination of methods to satisfy the DFA requirements:

> Rather, as our rules state, a funding arrangement qualifies for approval under subsection (vi) if it provides a level of decommissioning funding assurance equivalent to the level provided by the arrangements set forth in subsections (i) through (v). Applicants may *combine* different mechanisms to achieve this

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[61] In some cases, the discounted PCG may cover the shortfall, as noted in Enclosure 4 in the response to Comment 2. However, even where adequate to cover the shortfall, the discounted guarantee as proposed by NEI still fails to meet the requirements of § 50.75(b)(1) and (e)(1)(vi).

[62] Entergy Nuclear Operations (James A. Fitzpatrick Nuclear Power Plant; Indian Point Nuclear Generating Unit No. 3), CLI-00-14, 53 NRC 488, 550-551 (2001) [Hereinafter 53 NRC 488]

required equivalence. Subsection (vi) itself plainly establishes an equivalence test.

> (vi) Any other mechanism *or combination of mechanisms,* that provides, as determined by the NRC upon its evaluation of the specific circumstances of each licensee submittal, assurance of decommissioning funding *equivalent* to that provided by the mechanisms specified in paragraphs (e)(1)(i) through (v) of this section.[63] [Emphasis in original]

The Commission's statement does not carve out an exception for combinations of a PCG with an external sinking fund. Consequently, the sinking fund discount combination is required to be tested for equivalency. The response to Comment 8 provides further discussion of the reasons that a combination using the external sinking fund requires NRC approval under the equivalency test.

In its adjudication of the PASNY transfer order, the Commission described the guarantee as a "mere promise … to pay the money at some future time," which provides less assurance than money already deposited in a NDT.[64] Given that a non-discounted PCG does not provide financial assurance equivalent to money in a NDT, it logically follows that a discounted PCG would not achieve equivalency either.

A licensee's commitment would not be adequate since commitments are not enforceable. The Commission stated that the requisite equivalent assurance of decommissioning funding under § 50.75(e)(1)(vi) is provided collectively by the licensee's assurance provisions and the NRC staff's conditions.[65] Consequently, conditions may be imposed to ensure licensee performance. In past orders where § 50.75(e)(1)(vi) was used to approve non-standard methods, conditions were imposed to ensure performance. Conditions could be imposed in an order issued pursuant to the authority of § 50.75(e)(2), or in a license amendment. Both methods would permit hearings rights, which would provide a venue for public participation.

REGULATORY GUIDANCE

No regulatory guidance for reactors has been issued stating that adding an earnings credit or applying a discount to a PCG or self-guarantee is an acceptable means of meeting the regulatory requirements for either reactors or materials licensees.

In the PASNY transfer, the Commission stated that the end result of funding assurance was stated in NUREG-1577, Rev. 1:

> Third-party guarantee mechanisms, such as surety bonds or letters of credit, should guarantee the total amount of currently estimated decommissioning costs. If these mechanisms are used in combination with other assurance mechanisms, *the combined amount should at least equal current estimated decommissioning costs*.[66] [Emphasis in original]

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[63] 53 NRC 488, 546
[64] 53 NRC 488, 550
[65] Entergy Nuclear Operations (James A. Fitzpatrick Nuclear Power Plant; Indian Point Nuclear Generating Unit No. 3), CLI-00-14, 53 NRC 488, 546 (2001)
[66] Id. at 551, quoting NUREG-1577, Rev. 1, Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance, Section 2.f(2)

The criterion in NUREG-1577, Rev. 1 does not recognize a discounted PCG as an acceptable method to meet the regulatory requirement.

The Guidance of RG 1.159, Rev. 1, states:

> 2.1.2 The applicant or licensee should indicate that the method used provides, or will provide at the projected cessation of operations, an amount at least equal to the estimated or certified decommissioning cost for the facility, when earnings are taken into account as permitted by 10 CFR 50.75(e)(1)(i) and (ii). If a licensee uses a combination of different methods for assuring decommissioning funds, the combined total of the methods being used should equal the certification amount, plus adjustments projected to be needed.[67]

RG 1.159 recognizes the applicability of earnings credits only for the prepaid account and external sinking fund methods specified in 10 CFR 50.75(e)(1)(i) and (ii). It does not recognize taking an earnings credit for or giving a discount to a PCG as an acceptable method to meet the requirements. It states the combined total should at least equal the certification amount, which is the minimum DFA amount defined in § 50.75(c). It does not state that a smaller, discounted amount is acceptable.

An interesting conclusion can be drawn from NEI's September 2009 request to revise RG 1.159 to remove existing guidance stating that a combination should equal the certification amount. NEI's request is reproduced below. The existing guidance that NEI wanted to eliminate is shown in strikeout form. NEI's proposed addition, which changes the meaning of what constitutes the total amount, is shown in underline form:

> 2.1.2 The applicant or licensee should indicate that the method used provides, or will provide at the projected cessation of operations, an amount at least equal to the estimated or certified decommissioning cost for the facility, when earnings are taken into account as permitted by 10 CFR 50.75(e)(1)(i) and (ii). ~~If a licensee uses a combination of different methods for assuring decommissioning funds, the combined total of the methods being used should equal the certification amount, plus adjustments projected to be needed.~~ <u>If a licensee uses a combination of different methods for assuring decommissioning funds, the combined total of the methods being used should equal the current value of the certification amount.</u>[68]

NEI defined the "current value" as amount that would be necessary to put in a fund today to meet the minimum DFA requirement.[69] However, the "current value" is not the certification amount calculated by the formula of § 50.75(c). Using the definition proposed by NEI, the "current value" is the discounted amount of certification requirement of § 50.75(c), which is less than the certification amount. The requested strike out and insertion demonstrates NEI's conclusion that the NRC's existing guidance would have to be changed to be compatible with the discounting method proposed by NEI. The change would be necessary because the existing guidance conflicts with giving a discount on the DFA requirement. The existing guidance, shown in strikeout form, has been unchanged since it was originally issued in 1990.

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[67] RG 1.159, Rev. 1, "Assuring The Availability of Funds for Decommissioning Nuclear Reactors," p. 1.159-11, October 2003

[68] NEI September 2009 letter at 12

[69] Id. at 11

The persistence of the guidance provides additional support for the conclusion that the NRC did not intend to allow discounting when the financial assurance rules were first issued in 1988, and that the intention has not changed since that time.

Likewise, guidance for materials licensees has always stated that only non-discounted PCGs are acceptable. Materials licensee guidance for PCGs was first issued in 1990.[70] The early guidance stated that a PCG, if used, must at least equal the decommissioning cost of the facility.[71] Revised regulatory guidance for materials licensees was issued in September 2000 to clarify that no earnings credit could be taken for a PCG.[72] The materials guidance for PCGs was last revised in 2003 and issued in NUREG-1757, Vol.15. The 2003 guidance states:

> No credit is taken for earnings on any financial assurance mechanism (e.g., a parent company guarantee) that does not set aside actual funds as prepayment[73]

PRECEDENTS OF NON-DISCOUNTED PCGS

The requirements for the PCG and the closely related self-guarantee are specified in Appendices A and C to 10 CFR Part 30, respectively. In every instance where the regulations authorize the PCG or self-guarantee for use, the regulation refers to Appendix A or C. respectively, as its authoritative basis.[74] As discussed in the response to Comment 1, that common basis establishes a general rule for all reactor and materials licensees using the PCG of self-guarantee as a DFA method. Appendices A and C to Part 30 do not authorize licensees to give an earnings credit to, or take a discount for, a PCG or self-guarantee.

Since 1988, PCGs and self-guarantees have been approved for dozens of reactor and materials licensees.[75] When annual requalification is considered, over 200 guarantees have been approved without allowing an earnings credit or a discount. For example, self-guarantees covering four research and test reactors (RTRs) have been approved each year since 1993. In every instance, the guarantee did not allow discounting. Numerous non-discounted PCGs for reactors were also approved. For example, in 2003, NRC accepted non-discounted PCGs from Progress Energy in the amount of $276 million, to cover shortfalls at three units until license renewal could be obtained.[76] In 2009, NRC accepted only non-discounted PCGs to meet DFA requirements at 5 facilities. In 2011, the NRC accepted non-discounted PCGs to cover shortfalls at two facilities. As discussed in the response to Comment 2, of the three license transfer orders referred to as precedents by NEI, only two approved PCGs that did not cover the shortfall, while the PCG in the third order was adequate to cover the shortfall.

With respect to the amount of time needed to prepare and submit a PCG, there are now two examples demonstrating that 90 days is achievable by licensees. As stated in SECY-10-0084, Progress Energy submitted three non-discounted PCGs to cover shortfalls of $276 million at three of its nuclear facilities when it submitted its decommissioning fund status (DFS) report in

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[70] Standard Format And Content of Financial Assurance Mechanisms Required for Decommissioning Under 10 CFR Parts 30, 40, 70, And 72, Regulatory Guide 3.66, June 1990
[71] Id. Section 3.2
[72] NMSS Decommissioning Standard Review Plan, NUREG-1727, Section 15.3.3.10, September 2000
[73] Consolidated NMSS Decommissioning Guidance Financial Assurance, Recordkeeping, and Timeliness NUREG-1757, Vol. 15, Section 4.3.2.10, September 2003
[74] *See*§ 30.35, § 40.36, § 50.75, § 70.25, § 72.30
[75] Financial Assurance Inventory Log, Office of Federal and State Materials and Environmental Management Programs (FSME); Decommissioning fund status reports, Office of Nuclear Reactor Regulation
[76] Biennial Decommissioning Funding Status Report, p. 2, Progress Energy, March 28, 2003 (ML030970280)

2003. Recently, FirstEnergy Nuclear Operating Company stated in its 2011 DFS report that it would submit non-discounted PCGs to cover shortfalls of $95 million at two of its facilities, within 90 days of the date of its DFS submittal.

TRANSFER ORDERS APPLYING THE EQUIVALENCY TEST OF § 50.75(e)(1)(vi)

NRC has applied § 50.75(e)(1)(vi) in a number of license transfer orders to approve using a non-standard financial mechanism, subject to a number of conditions. Typically, the conditions required funds to be deposited into the licensee's NDT within a defined time period and assured the integrity of the funds during the time period before the funds were deposited.

In response to a contention admitted in the of the Fitzpatrick and Indian Point Unit 3 license transfer from the Power Authority of the State of New York to Entergy Nuclear Operations, Inc., the Commission explained the meaning of § 50.75(e)(1)(vi):

> In promulgating subsection (vi), we intended to give applicants the flexibility necessary to structure methods outside the parameters of any one of the five methods set forth in subsections (i) through (v), or to combine portions of those subsections in such a way as to provide the same end-result of funding assurance.[77]

However, the Commission stated that even where the reactor licensee provides extensive provisions in its application, the NRC may impose conditions to achieve the requisite equivalent assurance:

> We find that a multitude of provisions in the applications, as conditioned by the NRC Staff, collectively give us the requisite assurance, "equivalent" to the assurance given by the particular funding devices authorized by our rules, that the decommissioning funds will be available to PASNY. The extensive protective measures set forth in the applications satisfy us regarding the integrity and sufficiency of the PASNY - Entergy decommissioning funding arrangements.[78]

The Commission emphasized that reactor licensees must meet the equivalency test when they propose a combination of methods to satisfy the DFA requirements:

> [A]s our rules state, a funding arrangement qualifies for approval under [§ 50.75(e)(1)](vi) if it provides a level of decommissioning funding assurance "equivalent" to the level provided by the arrangements set forth in subsections (i) through (v). Applicants may *combine* different mechanisms to achieve this required equivalence. Subsection (vi) itself plainly establishes an "equivalence" test:
>
> > (vi) Any other mechanism *or combination of mechanisms,* that provides, as determined by the NRC upon its evaluation of the specific circumstances of each licensee submittal, assurance of decommissioning funding *equivalent* to that provided by the mechanisms specified in paragraphs (e)(1)(i) through (v) of this section.[79] [Emphasis in original]

[77] Entergy Nuclear Operations (James A. Fitzpatrick Nuclear Power Plant; Indian Point Nuclear Generating, Unit No. 3), CLI-00-14, 53 NRC 488, 550-551 (2001)
[78] Id. at 546
[79] Id. at 546

In the event a non-standard mechanism approved by the NRC is challenged, the licensee bears the burden to show that it meets the safety standards of the regulations:

> Where (as here) an adjudication goes to hearing, it is Applicants' burden to show, by a preponderance of the evidence, that they meet our safety standards - in this case, our financial qualifications rule.[80]

The Commission stated that DFA decisions in license transfer orders have limited value as precedents, especially for non-standard methods of providing DFA:

> We see no risk here of a dangerous precedent. In the area of decommissioning funding assurance, each transfer application is examined *on its own facts.* This will be especially true of applications seeking to use an assurance other than those specifically described in sections 50.75(e)(1)(i)-(v). … Because of the fact-driven nature of our decommissioning rulings in this proceeding, their precedential value is, as a practical matter, limited to an indication of the Commission's openness to funding arrangements not specifically enumerated in subsections (i)-(v).[81] [Emphasis in original]

The Commission stated that a guarantee provided less assurance than an NDT:

> [T]he financial assurance at issue here is actually *greater* than that provided by a surety or parent - Applicants' assurance takes the form of money that has already been deposited in the two funds, as opposed to a mere promise of a surety, guarantee, or insurance policy to pay the money at some future time.[82]

Four license transfer orders that included evaluations under § 50.75(e)(1)(vi) to accept non-standard financial methods for DFA are outlined below. A tabulation of the four orders is in the table titled, "Application of 10 CFR 50.75(e)(1)(vi) to Previous License Transfer Orders."

In each application, the non-standard DFA involved funds held in a NDT by a former licensee, which were kept for a period of time before turning over to the new licensee. The specific circumstances of the applications included strong protections of the NDT, enforceable requirements to pay over the funds at the agreed upon time, and continuing government oversight of the funds while being held by the non-licensee. Tax issues provided the motivation to offer the non-standard methods. Where the non-licensee was a private company, the holding time was relatively short, around 1 year. Government agencies were allowed to hold the funds until the time of decommissioning. The funds equaled or exceeded the total DFA required. The non-licensees remained under State government oversight, which would assure the funds were not spent on other purposes, contracts were in place to require payment to the new licensee, and the NDTs had trustees to preserve the funds.

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[80] Id. at 517
[81] Id. at, 556-557
[82] Id. at 550

Application of 10 CFR 50.75(e)(1)(vi) to Previous License Transfer Orders

Reactor Facility	Status of NDT Holder	Non-Standard Mechanism Approved	Specific Circumstance
Indian Point Unit 3[83]	Government agency	Maintain NDT until decommissioning	Avoid capital gains tax; strong NDT protections
Crystal River Unit 3[84]	Government agency	Maintain NDT until decommissioning	Resolve tax issues; strong NDT protections
Three Mile Island Unit 1[85]	Private company	Temporary holding of NDT for about 1 year	Resolve tax issues; strong NDT protections
Hope Creek [86]	Private company	Temporary holding of NDT for about 1 year	Resolve tax issues; strong NDT protections

Order Approving Transfer of License from the Power Authority of the State Of New York (PASNY) to Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc. and Approving Conforming Amendment, November 9, 2000, (ML003767953)

Entergy wanted to avoid any risk of having to pay capital gains tax on the funds accumulated by PASNY to decommission Indian Point Unit 3 (IP3). The parties agreed that PASNY would continue to hold the funds in the decommissioning trust until such time as IP3 is decommissioned, when the funds would be disbursed to Entergy. The arrangement was acceptable under § 50.75(e)(1)(vi) for the following reasons: (1) PASNY fund held $308.4 million, which exceeded the $280 million required under the generic cost formula of § 50.75(c), even without taking the 2% earnings credit; (2) the trust is not subject to the claims of PASNY's creditors; (3) PASNY held a very strong AA bond rating, which reduced the potential for long-term default; (4) modifications to the trust agreement; (5) PASNY waived right to challenge NRC jurisdiction regarding use of the decommissioning trust funds; (6) fiduciary duties of the trustee provided additional assurance that funds will remain available; (7) the money needed is already set aside in trust; (8) PASNY is a political subdivision of the State of New York, which provides assurance that the contracts between PASNY and Entergy will remain in force.

A contention was submitted challenging the DFA methods approved in this order. The results of the Commission's adjudication are detailed in the preceding paragraphs of this section.

Order Approving the Transfer of License for Crystal River Unit 3 to the Extent Held by the City of Tallahassee to Florida Power Corporation ad Approving Conforming Amendment, September 8, 1999 (ML020670117)

The City of Tallahassee (City) (1.3333% owner-licensee) sold its interest to Florida Power Corporation (FPC). The parties agreed that City would continue to hold the decommissioning trust funds accumulated to date, rather than transfer the funds to FPC. City's tax-exempt status made it likely that fund accumulation would be greater if left with the City. When the funds are needed for decommissioning, the City will disburse them to FPC. FPC's trust fund held $309.7

[83] ML003767953
[84] ML020670117
[85] ACN# 9905180206
[86] ML003683613

million, which exceeded the $261.9 million estimated cost of decommissioning. The arrangement was acceptable under § 50.75(e)(1)(vi) for the following reasons: (1) the available funds exceeded 10 CFR 50.75 requirement, even without the City's decommissioning trust funds; (2) the City is able to set its own rates and has an assured source of revenue for decommissioning; and (3) the City agreed to pay over trust funds to FPC when needed for decommissioning.

Safety Evaluation Transfer of Three Mile Island Unit 1 from General Public Utilities, Inc. to Amergen Energy Company, LLC, April 12, 1999 (ACN# 9905180206)

The parties agreed that GPU would hold the decommissioning trust it had accumulated for Three Mile Island Unit 1 (TMI 1) until the US Internal Revenue Service made a decision on the tax status of the transferred funds, when the funds would be transferred to Amergen. The arrangement was acceptable under § 50.75(e)(1)(vi) for the following reasons: (1) the amount in the fund ($303 to $320 million), depending on the sale closing date, exceeded the generic formula amount ($269 million); (2) GPU voluntarily accepted NRC jurisdiction over the fund while held by GPU; (3) GPU could pass the financial test for a parent company guarantee; (4) the funds set aside are specifically provided for the decommissioning obligation; (5) fiduciary duties of the trustee provide assurance that the funds will be reserved for decommissioning; (6) GPU will remain a regulated utility and the New Jersey Public Utilities Commission will assure the fund will not be used for any purpose other than decommissioning; (7) GPU is contractually obligated to pay over the funds to Amergen; (8) the arrangement is only temporary.

Order Approving the Transfer of License for Hope Creek Generating Station, to the Extent Held by Public Service Electric and Gas Company, to PSEG Nuclear Limited Liability Company and Approving Conforming Amendment, February 16, 2000 (ML003683613)

In accordance with a Summary Order from the New Jersey Public Service Commission, Public Service Electric and Gas Company (PSE&G) transferred its licenses to a newly formed nuclear generation affiliate, PSEG Nuclear. The new affiliate would own and operate Hope Creek and Salem, and own a share of the Peach Bottom units, but not operate them. However, PSE&G wanted to hold the trust funds for some time after the license transfer to resolve tax issues. Thus, PSEG Nuclear would not meet the DFA requirements at the time of transfer. The arrangement was acceptable under § 50.75(e)(1)(vi) for the following reasons: (1) funds would be adequate for decommissioning at time of shutdown based on receipt of non-bypassable charges and the earnings credit; (2) PSE&G would pass the financial test to pay the $514.7 million held in the trust funds at the time of the transfer; (3) actual possession of the funds specifically set aside to pay the obligation exceeds the requirement for a surety company; (4) trust agreement provides additional assurance that funds will be used for decommissioning; (5) PSE&G would remain a public utility, and New Jersey was not likely to allow the funds to be used for other than decommissioning purposes; (6) the arrangement is only temporary, until the tax issue is resolved.

VULNERABILITIES OF THE PCG AND SELF-GUARANTEE

The PCG and self-guarantee are subject to a number of vulnerabilities when used as financial assurance mechanisms. First, there is no requirement to set aside funds, or to provide security for the guaranteed amount. The parent company is not required to hold funds to pay the guarantee in a segregated account outside the parent company's control. Consequently, the assets that would be called upon to pay the guarantee, if needed, are subject to attachment by

creditors, can be pledged as collateral for other purposes, may be lost in unprofitable business ventures, and are vulnerable in bankruptcy. Unlike a bank, insurance company, or surety, the parent company is not an independent third party, and it can be affected by financial stress of its subsidiary-licensee, while the subsidiary-licensee can be affected by the financial stress of its parent. As a result, the parent and licensee may be subject to a common mode financial risk. The self-guarantee has similar risks, but is directly affected by the licensee's financial stress.

In addition to the financial risks involved, the PCG raises certain adverse incentives, as discussed in the regulatory history section of this paper. Briefly, the PCG provides incentives to delay or cease deposits into the NDTs, and to shift costs. (See the section on the 1998 Decommissioning Rule for a discussion of adverse incentives.) A discounted PCG provides a lower level of assurance than a non-discounted PCG by the fact that it covers a lower amount of the decommissioning costs, which may result in a shortfall in DFA. It provides a greater opportunity to take advantage of the adverse incentives provided by the non-discounted PCG by virtue of its lower effective ratio of assets and net worth to the decommissioning cost. The Commission stated that the guarantee method, which represents a promise to pay at some time in the future, provides less assurance than funds already deposited and protected in a decommissioning trust.[87]

FINANCIAL ASSURANCES REQUIRED BY EXELON FROM ZIONSOLUTIONS, LLC

The 2010 transfer of the Zion facility from Exelon to ZionSolutions, Inc. (ZS) provides a comparison of NRC DFA requirements to a market-based resolution of the financial risks of non-performance of decommissioning by the licensee. It shows how knowledgeable industry participants with experience in managing risk apportioned the financial risks of non-performance of decommissioning. It provides the first instance of a merchant plant that must depend on the NDT as the only source of funding. As shown below, Exelon required EnergySolutions, Inc. to accept all the risk and to provide comprehensive financial assurances. The risks identified and mitigated by the financial assurance agreements between Exelon and EnergySolutions, Inc. are the same risks that concern stakeholders in local communities, the States, and tribal governments.

When Exelon sold its Zion facility to Energy Solutions, Inc. (ES) in 2010, it retained ownership of the land. ES created ZionSolutions, LLC (ZS) to decommission the Zion facility in exchange for the accumulated funds in the Zion NDT. As part of its due diligence, Exelon first used a Monte Carlo analysis to assess the financial risks it faced by depending on ES to perform the project.[88] Exelon then transferred the risks to ES and ZS through an extensive set of financial assurances. Exelon explained that it "expect[ed] them [ZS] to eat into their profits a little bit before they finished the job completely."[89] To assure performance, ES was required to provide a PCG to ZS that exceeded NRC requirements. The ES guarantee is "absolute, unconditional and irrevocable, and nothing whatever except actual full payment and performance of the Guaranteed Obligations" will satisfy the guarantee.[90] The guarantee has no cap and no discounts. Exelon also required EnergySolutions to provide 7.5 million cubic feet of disposal

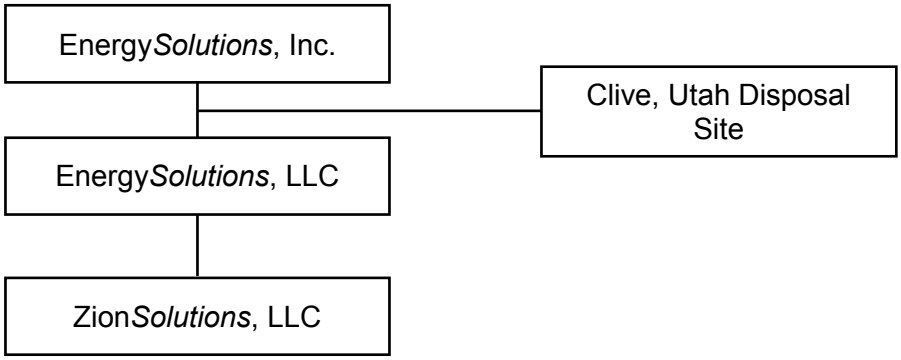
[87] Entergy Nuclear Operations (James A. Fitzpatrick Nuclear Power Plant; Indian Point Nuclear Generating Unit No. 3), CLI-00-14, 53 NRC 488, 550 (2001)
[88] Transcript, Follow-up Meeting, Statement of Mr. Levin (Exelon), June 8, 2011, p.110 (ML111650033)
[89] Id.
[90] Application for License Transfers, Enclosure 7, Form of EnergySolutions Performance Guaranty, January 25, 2008 (ML080310521) [Hereinafter Zion Application]

capacity with "no fee, charge, or other cost."[91] The guaranteed capacity is 125% of the estimated disposal volume needed to complete the project.[92] In addition, Exelon has a place on the licensee's Board of Directors, with the right to block the licensee from instituting a bankruptcy proceeding.[93] Exercising that right would force ZS to keep its workforce in place and force ES to pay for decommissioning, despite insolvency on ZS's part.

The parties agreed that the NDT was adequate to pay for the decommissioning. However, Exelon required ZionSolutions to obtain an additional $200 million letter of credit. Exelon stated that the $200 million was "just additional insurance that we at Exelon felt we needed to have in order to convince all of our parties that we were in good shape to go forward."[94]

The illustration below shows the corporate structure governing the Zion facility licensee. ZionSolutions, LLC (ZS) holds the Zion license, and must meet the decommissioning obligations specified by the NRC. EnergySolutions, LLC is an intermediate parent company, and EnergySolutions, Inc. (ES, Inc. or ES) is the parent. The structure is designed to give ZS "bankruptcy remoteness" from financial distress of the parents and other affiliated companies. Among other items, bankruptcy remoteness means that ZS cannot file for bankruptcy without the consent of Exelon. The guarantees that ES, Inc. was required to provide to Exelon assures that any financial distress of ZS will be borne by ES, Inc. Ownership of the Clive, Utah disposal site figured prominently in the agreement, because it enabled Exelon to obtain an easement for cost-free disposal capacity, thus guaranteeing zero increases in disposal costs.

EnergySolutions Corporate Structure for Zion Decommissioning



The financial assurances required of ZS and its parents included the following agreements:

- Parent Company Performance Guaranty
- Irrevocable Easement for Disposal Capacity
- Asset Sale Agreement
- Credit Support Agreement
- Limited Liability Agreement of ZionSolutions, LLC

[91] Zion Application, Exhibit G, Irrevocable Easement for Disposal Capacity..
[92] Zion Nuclear Power Station Units 1 and 2 Amended Post-Shutdown Decommissioning Activities Report, March 17, 2008, p.14 (ML080840398)
[93] Zion Application, Limited Liability Company Agreement of ZionSolutions, LLC, Sec. 9(d)(iii), Management, and Schedule A, Definitions, "Material Action"
[94] Transcript, Decommissioning Funding Workshop, Common Sessions, statement of Mr. Levin, March 2, 2011, p.191 (ML110810747)

Parent Company Performance Guaranty [95]

The corporate structure normally protects the parent from incurring any liability for the obligations of its subsidiaries. The principle that a parent company has no liability for the acts of its subsidiary is recognized by the United States Supreme Court:

> It is a general principle of corporate law deeply "ingrained in our economic and legal systems" that a parent corporation (so-called because of control through ownership of another corporation's stock) is not liable for the acts of its subsidiaries.[96] *United States v. Bestfoods*, 524 U.S. 51, 61 (1998)

In the Zion case, the parent - subsidiary relationship would shield ES from liabilities attaching to ZS, if ZS failed to complete the Zion facility decommissioning. However, Exelon required ES and ZS to establish a parent guaranty that would pierce the shield provided by corporate law. The guaranty exceeds the requirements of the NRC's PCG, and it passes ZS's liabilities up through the corporate chain directly to ES, Inc. One of the limitations of the NRC's PCG is that the parent can make payment under the PCG and absolve itself of any further liability for the performance of the decommissioning. The Zion guaranty removes that limitation by requiring ES, Inc. and ES, LLC to absolutely, unconditionally, and irrevocably guarantee both payment and performance. As a result, ES, Inc. is responsible for any cost overruns by ZS, and must pay whatever it takes to complete the decommissioning. Relevant sections of the guaranty agreement are shown below, with emphasis added to highlight the extent of the guaranty.

> Section 2. Guaranty. As an inducement to Beneficiary[Exelon], for and in consideration of Beneficiary entering into the Asset Sale Agreement, Guarantor *[ES, Inc. and ES, LLC] hereby absolutely, unconditionally, and irrevocably guarantees* to Beneficiary and its successors, endorsees and permitted assigns, *as primary obligor and not merely as a surety, the full and prompt payment and performance, when due, by Counterparty [ZS] of all of its present and future obligations* that are required to be paid or performed in accordance with the Guaranteed Agreements (collectively, the "Guaranteed Obligations"). The Guaranteed Obligations shall include, without limitation, all reasonable costs and expenses (including reasonable attorneys' fees and disbursements), if any, incurred in enforcing Beneficiary's [Exelon] rights under this Guaranty, but only to the extent that Beneficiary is successful in enforcing its legal rights under this Guaranty. *This is a guaranty of payment and performance and not of collection*. [Emphasis added]
>
> Section 3. Guaranty Absolute. The liability of Guarantor [ES, Inc. and ES, LLC] under this Guaranty shall be absolute, unconditional and irrevocable, and nothing whatever except actual full payment and performance of the Guaranteed Obligations (and all other debts, obligations and liabilities of Guarantor under this Guaranty) shall operate to discharge Guarantor's liability hereunder. [Emphasis added]

Section 3 continues with 15 subsections that require ES, Inc. and ES, LLC to waive the legal defenses that would otherwise be available to contest the enforcement of the guaranty. The

[95] Zion License Transfer Application, Enclosure 7, January 25, 2008 (ML080310521)
[96] *United States v. Bestfoods*, 524 U.S. 51, 61 (1998)

first waiver is an anti-bankruptcy clause that requires ES to pay under the guaranty, regardless of the outcome of any bankruptcy proceeding. The final waiver is a catch-all to cover anything that wasn't already named in the list. The list is summarized below.

3.1 Any event of bankruptcy, reorganization, or insolvency, even if the Bankruptcy Court disallows any claim by Exelon or requires Exelon to return any payment as a fraudulent transfer under the Bankruptcy Code
3.2 Any amendment to the Guaranteed Agreements, except for amendments that materially increase ES's liability and ES does not consent, if consent is required
3.3 Exercise, non-exercise, or delay in exercising any right under Agreement
3.4 Any change or waiver of any term of the Guaranteed Obligations
3.5 Any assignment or transfer of rights under the Guaranty by Exelon, including use as security for financing
3.6 Any merger or change in corporate existence or cessation of the existence of ES or ZS
3.7 Any change in ownership or control of ES or ZS
3.8 Any sale or transfer of ES interests in ZS
3.9 Inaccuracy or breach of any representations or warranties by ZS or Exelon
3.10 Failure to create, perfect, or protect any security interest or collateral
3.11 The existence, release, settlement or compromise of any security or collateral or failure to enforce such guaranty
3.12 The existence of any claim or other rights which ES may have against Exelon
3.13 The validity of this Guaranty, the Guaranteed Agreements, or any provision of law purporting to prohibit payment or performance by ZS
3.14 The absence of any notice to, or knowledge by, ES of the existence or occurrence of any of the matters or events set forth in the foregoing clauses
3.15 Except as provided herein, any other circumstances which might otherwise constitute a defense to, or discharge of, ES or ZS in respect of the Guaranteed Obligations or a legal or equitable discharge of ZS in respect thereof, including, a discharge as a result of any bankruptcy or similar law.

Section 4 adds more waivers of legal defense, including waiving ES's right to obtain reimbursement of expenses from its subsidiary, ZS. The list is summarized below.

4.1 ES irrevocably, unconditionally and expressly waives any action, benefit, or advantage that may delay, prevent, or otherwise affect ES's performance of its obligations, or enforcement by Exelon, of the terms of the Guaranty
4.2 ES irrevocably, unconditionally and expressly waives all notices of every kind, including any fact that might materially increase the risk to ES, that are not specifically required under the Guaranteed Obligations, and waives the benefit of all provisions of law that are in conflict with the Guaranty
4.3 ES irrevocably, unconditionally and expressly waives promptness of any notice and any requirement that Exelon must protect any security, or first proceed against ZS or any other Person or guaranty
4.4 ES irrevocably, unconditionally and expressly waives (i) any right to bring a case against ZS; (ii) any subrogation of rights of Exelon against ZS until the Guaranteed Obligations have been paid and performed in full; (iii) any setoffs or claims against Exelon or ZS that would impair Exelon's rights against ES; and (iv) any right of reimbursement by ZS
4.5 Notwithstanding, ES shall be entitled to defenses based on termination of the

> Agreement if ZS is not in breach or the failure of Exelon to perform its obligation under the Agreement that adversely affects ZS's performance

In the event that the guarantees prove insufficient, despite their comprehensiveness, Section 8 states that Exelon can require ES, Inc. to provide additional instruments upon written demand:

> Section 8. Continuing Guarantee. Guarantor [ES] agrees, upon the written request of Beneficiary, to execute and deliver to Beneficiary any additional instruments or documents necessary or advisable from time to time, in the reasonable and good faith opinion of Beneficiary [Exelon], to cause this Guaranty to be, become or remain valid and effective in accordance with its terms.

The comprehensive nature of the Zion parent guarantee can be assessed using a checklist developed by Moody's Investors Service to evaluate whether a guarantee is sufficiently strong to accept the parent's credit rating as guarantor for the subsidiary.[97] To achieve pass through of the parent's credit, the guarantee must assure that the parent will not assert any defense to payment. Moody's identifies 9 characteristics of the ideal guarantee to achieve credit substitution. The Zion guaranty displays all 9 characteristics. On the other hand, the NRC PCG agreement explicitly covers only one the characteristics – it is enforceable by virtue of the guarantor's signature. However, the NRC PCG is not irrevocable or unconditional, and it does not have the explicit listing of waivers of legal defenses found in the Zion guaranty.

Irrevocable Easement for Disposal Capacity[98]

In its application, ES, Inc. stated that it could guarantee zero increases in disposal costs by virtue of its ownership of the Clive, Utah radioactive waste disposal site. The agreement with Exelon included an irrevocable easement to 7.5 million cubic feet of disposal capacity. The easement guaranteed that the capacity would be available with no fee, charge, or other cost. The grant of easement added a 25% contingency, or 1.5 million cubic feet, to the expected waste volume of 6 million cubic feet.

Three significant terms of the easement substantially reduced the risk of cost overruns in the Zion case. First, the easement was granted to Exelon. As the landowner, Exelon faced the risk that ZS may fail to complete the decommissioning project. In that event, Exelon would become the unwilling possessor of radioactive material on its property and would have to complete the decommissioning at its own expense. The grant of the easement to Exelon guaranteed that if ZS did not complete the project, then any radioactive material remaining could be disposed of at no charge in the Clive, Utah disposal site. Second, the easement could be assigned by Exelon to another company that might take over the Zion decommissioning project if ZS failed and its interests were sold to another party to complete the project. The third term provided that the covenants run with the land. As a result, any subsequent owner of the Clive Site would be bound by the same covenants, regardless of the fate of ES, Inc. The several terms working in concert assure that disposal capacity at no charge will be available to radioactive waste from the Zion decommissioning whether or not ZS and ES perform, or even cease to exist. (Note Section 3.6 of the guaranty, listed above, specifically waived ZS and ES's defenses based on cessation of existence.)

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[97] Moody's Investors Service, NRC Decommissioning Workshop, Appendix: Credit Substitution, March 2, 2011 (ML110560780)

[98] Zion License Transfer Application, Asset Sale Agreement, Appendix G, January 25, 2008 (ML080310521)

Asset Sale Agreement

The Asset Sale Agreement defines numerous obligations for the parties. Of interest are the requirements that protect Exelon from increasing costs, Exelon's control of disbursements, and the requirement to mitigate shortfalls within 90 days.

Exelon protected itself against possible increases in decommissioning costs in Section 6.18 of the Asset Sale Agreement:

> In the event that the NRC, the ICC [Illinois Commerce Commission] or other Governmental Authority requires Buyer [ZS] to provide Decommissioning funding assurance in an amount in excess of the Decommissioning Funds, Buyer, Buyer's Parent [ES, LLC] and/or Guarantor [ES, Inc.] (or such other entity as shall be acceptable to the NRC) shall post a guaranty or other financial assurances or take such other action as is sufficient to cover such excess Decommissioning funding in such form as required by the such Governmental Authority.

Section 6.21.7 allows Exelon to control the disbursement of funds from the NDT to pay for decommissioning costs; however, such payment may occur only after the expenses have been paid or are due and payable in cash:

> Buyer [ZS] shall not request a disbursement … if Buyer has not paid for such materials or services or Buyer's obligation to pay for such materials or services is not due and payable in cash.

Section 6.21.5 and 6.21.6 provide a procedure to be followed if the projected expenses exceed the remaining funds in the NDT. In that case, ZS must submit a "Deficiency Certification" to Exelon identifying the shortfall within 30 days. For reference, NRC licensees report the status of their NDT funds every two years, or annually, if in decommissioning or involved in a merger or acquisition. Under Section 6.21.6, ZS has 90 days to mitigate the shortfall. ZS has three choices: (1) reduce its cost to complete the decommissioning; (2) increase the amount of financial assurance by using a letter of credit; (3) defer any additional reimbursement of costs until the remaining costs are covered by the NDT. For reference, the guidance of RG 1.159 states that is acceptable for a merchant plant licensee to mitigate the shortfall two years after notification, and for public utility licensees to take five years.

Credit Support Agreement[99]

NRC regulations require the licensee to provide assurance at any time during the life of the facility, through termination of the license, that adequate funds will be available to complete decommissioning.[100] Exelon imposed requirements on ZS that exceeded the NRC requirement to provide adequate funds.

The NRC requires that the decommissioning cost estimate must be covered. In the Zion case, ZS was required to provide financial assurance in excess of the cost estimate. Although the parties agreed that the NDT funds were adequate to complete the decommissioning project,

[99] Zion License Transfer Application, Asset Sale Agreement, Exhibit F, January 25, 2008 (ML080310521)
[100] Decommissioning of Nuclear Power Reactors, Final rule, July 29, 1996, 61 FR 39278

Exelon required ES, Inc. to provide an additional $200 million letter of credit (LOC) in Section 2.1.1 of the Credit Support Agreement.[101] Exelon stated that the $200 million was "just additional insurance that we at Exelon felt we needed to have in order to convince all of our parties that we were in good shape to go forward."[102] The LOC requirement forced ZS to provide financial assurance of about 120% of the original cost estimate of $978 million.[103]

Exelon will permit ZS to reduce the LOC as the work progresses and the remaining cost to complete decommissioning decreases. However, in Section 2.2 of the Credit Support Agreement, Exelon required ZS to maintain financial assurance equal to 200% of the remaining costs before any reduction can be made to the LOC. After any reduction, the sum of the face amount of the LOC and the NDT must be at least 200% of the remaining costs. The funds in the NDT must be at least 100% of the remaining costs. These conditions forbid ZS from substituting the LOC for funds in the NDT.

The effect of the two conditions in Sections 2.1.1 and 2.2 of the Credit Support Agreement is that ZS must provide 120% of the cost estimate to begin the project, and the percentage will increase to 200% of the remaining cost as the work progresses.

Limited Liability Agreement of ZionSolutions, LLC[104]

Although Exelon transferred its license and sold its interests in the Zion facility to ZS, Exelon holds a position in ZionSolutions, LLC. Exelon is a Class B member, with no interest in the profits, losses, and capital of ZS, and no right to any distributions of ZS assets. Exelon has no voting rights as a member of ZS;[105] however, Exelon has the power to appoint the Exelon Director to the Board of Directors of ZS.[106] In that capacity, Exelon has the power to allow or prevent "material actions" by the ZS Board.[107] Those actions are defined in Schedule A of the LLC Agreement, which include any filing for Bankruptcy or other proceedings of insolvency. This power allows Exelon to block ZS from seeking relief in a bankruptcy proceeding, and, in conjunction with the parent guaranty from ES. Inc., force ES to perform under the guaranty.

Summary of Financial Assurances Imposed on ZS by Exelon

In summary, the financial assurances for the Zion facility decommissioning include:

- The NDT ($788 million as of 12/31/2010)
- $200 million LOC
- Unlimited parent company performance guarantee
- No-cost easement for disposal capacity
- 90 day time limit to cure a shortfall in financial assurance
- 120% excess financial assurance at start of decommissioning
- 200% excess financial assurance of remaining cost before reducing LOC
- Exelon is protected from any increases in cost due to government requirements

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[101] Zion License Transfer Application, Exhibit F, Credit Support Agreement, January 25, 2008 (ML080310521)
[102] Transcript, Decommissioning Funding Workshop, Common Sessions, statement of Mr. Levin, March 2, 2011, p.191 (ML110810747)
[103] Safety Evaluation Report, Zion Nuclear Power Station Units 1 and 2, p.4, May 4, 2009 (ML090930063)
[104] Zion License Transfer Application, Limited Liability Agreement of ZionSolutions, LLC, January 25, 2008 (ML080310521)
[105] Id. Section 5
[106] Id. Section 10
[107] Id. Section 9 and Schedule A

- Exelon is a member of ZionSolutions, LLC
- Exelon has the right to appoint a Director to the ZS Board of Directors, with power, among other actions, to block ZS from instituting bankruptcy proceedings

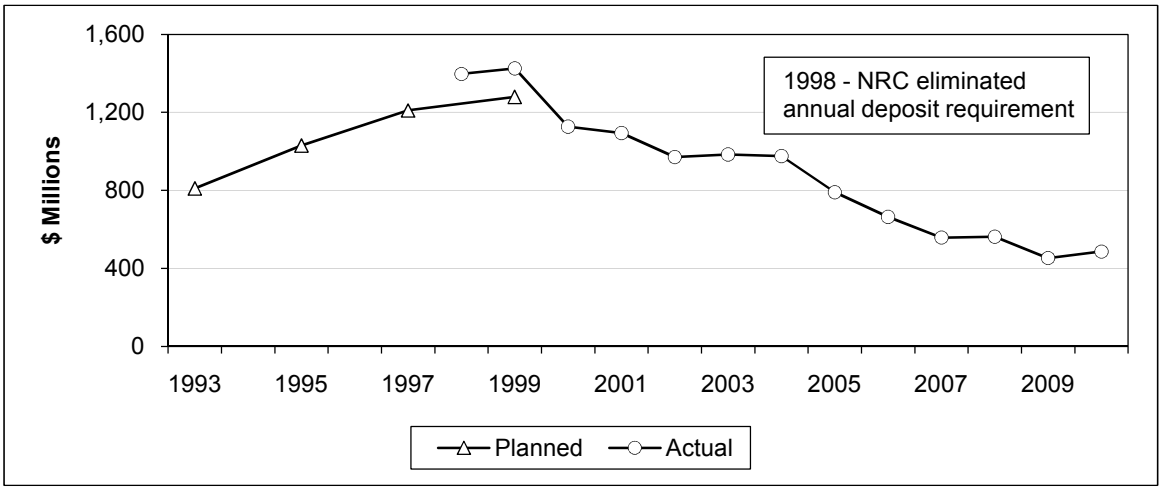
The 2010 transfer of the Zion facility from Exelon to ZionSolutions, Inc. (ZS) provides a comparison of NRC DFA requirements to a market-based resolution of the financial risks of non-performance of decommissioning by the licensee. It provides the first instance of a merchant plant that must depend on the NDT as the only source of funding. The agreements between Exelon and ZS contain many financial assurance mechanisms that exceed NRC requirements to address the financial risks of non-performance by the licensee. The risks mitigated by the agreements between Exelon and ZS are the same risks that concern stakeholders in local communities, States, and tribal governments.[108]

HISTORICAL DATA

Fund Contributions

The following chart shows the long-term downward trend in NDT contributions that began when the NRC eliminated the requirement to make annual deposits. The chart below shows planned contributions from1993 to 1999 and actual contributions starting in 1998 and afterward. Planned contribution data is collected biennially by NISA Investment Advisors, based on a survey of Trust Sponsors that started in 1993.[109] Actual fund contribution data is collected by Duff & Phelps Investment Management Co. based on publicly available records.[110] Duff & Phelps began collecting data on actual contributions starting in 1998.[111]

NDT Contributions by Year



Before 1998, planned trust fund contributions had been rising, as shown in the chart titled, :NDT Contributions by Year." The 1998 Decommissioning Rule, effective in November 1998,

[108] State of New York Office of the Attorney General, Issues Related to Decommissioning Funding, March 2, 2011 (ML110560594)
[109] NISA Investment Advisors, 2010 Survey of Trust Sponsors, *available at* http://www.nisanet.com
[110] Transcript, Decommissioning Funding Workshop, Breakout Session 2, statement of Mr. Krause (Duff & Phelps), p.43-47, March 2, 2011 (ML110750355)
[111] Duff & Phelps, Historical NDT Contributions, p.3, July 22, 2011 (ML11249A221)

eliminated the requirement for power reactor licensees to make contributions to their NDTs. The downward trend in contributions after the requirement was eliminated is apparent in the chart.

Analysis of the 2009 decommissioning fund status reports indicates that approximately 80% of the $2.4 billion shortfall was reported by facilities that had delayed or ceased making payments into their NDTs.

Rate of Return Compared to Decommissioning Cost Escalation

The regulations of 10 CFR 50.759e)(1)(i) and (ii) allow up to a 2% real rate of return to place a value on the projected future earnings that may be credited for DFA purposes. If the licensee's rate regulatory authority permits, a higher real rate of return may be used. However, a negative real rate of return can result when the expected growth rate of the NDT lags the cost escalation rate for decommissioning. Examples are discussed below. Consequently, when requesting approval for a discounted PCG, the licensee needs to justify the real rate of return it selects.

A negative real rate of return can result when the growth rate of the NDT lags behind the cost escalation rate for decommissioning. For example, negative earnings credits were submitted for the NDT established for the Calvert Cliffs facility for approval in a ratemaking case.[112] In 2006, Baltimore Gas and Electric Company (BGE), a subsidiary of Constellation Energy Company, submitted a detailed assessment of its NDT investment performance and decommissioning cost escalation. The chart below illustrates the results of the assessment. Two independent experts evaluated the cost escalation rate for decommissioning. The experts estimated that the decommissioning cost escalation "premium" for Calvert Cliffs was about 2.6% per year greater than the rate of general inflation.[113] The NDT fund performance was based on actual returns from 1989 to 2005. BGE determined that the NDT real rate of return projection was negative, approximately - 0.33% per year.[114] As a result, BGE required significant rate relief to accumulate adequate funds for decommissioning. The NRC formula amount for Calvert Cliffs Units 1 and 2 was $644 million in 2005.[115] The future cost of decommissioning for the Calvert Cliffs facility was approximately $5 billion at that time.

The chart titled, "2006 Submittal for Decommissioning Rate Relief for Calvert Cliffs Units 1 and 2," shows BGE's analysis. BGE concluded that it would need a rate increase from $18.6 million to $25 million per year until 2033 in order to accumulate the funds needed to decommission Calvert Cliffs.

Maryland Senate Bill 1013, which was signed into law on April 24, 2008, authorized continued collections by BGE of $18.7 million annually in decommissioning charges for Calvert Cliffs through December 31, 2016. However, the Bill required BGE to provide credit for residential customers equal to the approximately $18.7 million dollars collected annually for decommissioning and relieved ratepayers of all nuclear decommissioning liability for CCNPP, Inc., which is the NRC licensee for Calvert Cliffs Units 1 and 2.[116]

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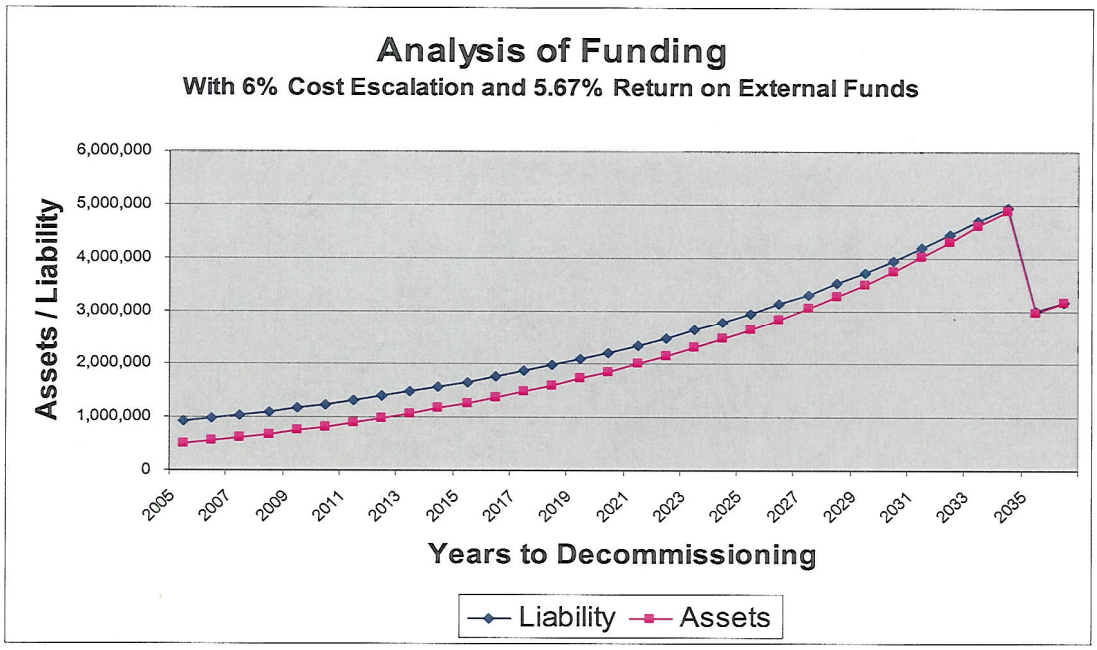
[112] Letter, BGE to Public Service Commission of Maryland, Re: Case No. 8794/8804 Compliance Filing, April 3, 2006, *available at* http://webapp.psc.state.md.us, Case No. 8804, Document No. 340 [Hereinafter BGE 2006 Letter]
[113] Id. Attachment 6, Appendix A
[114] 5.67% return on external funds less 6% cost escalation = -0.33%
[115] Constellation Energy 2006 Biennial Fund Report, Attachment 1, p.1, February 8, 2006 (ML060450309)
[116] Revised Safety Evaluation by the Office of Nuclear Reactor Regulation: Direct and Indirect Transfers of Control of Renewed Facility Operating Licenses Due to the Proposed Corporate Restructuring Calvert Cliffs Nuclear Power

2006 Submittal for Decommissioning Rate Relief for Calvert Cliffs Units 1 and 2[117]



The negative growth rate illustrated by BGE is not untypical. ABZ, Inc. was one of the decommissioning cost experts that provided information for BGE's 2006 submittal to the Public Service Commission of Maryland. ABZ, Inc. also participated in the recent March 2011 workshop and June 2011 follow-up meeting. They estimated that the industry-wide aggregate investment returns of NDT funds has not achieved a 2% real rate of growth when compared to the cost escalation in decommissioning as recorded in NUREG-1307, "Report on Waste Burial Charges." ABZ, Inc. evaluated publicly available historical information on NDT fund growth after-tax growth rates.[118] They estimated the real rates of return based on decommissioning cost escalation rather than general inflation. The estimates are shown in the table below. The 2006 Calvert Cliffs rate case result falls roughly mid-range for all PWR decommissioning fund performance.

Average After-Tax Annual Growth Rate of NDTs Compared to Decommissioning Cost Escalation Rate

Period	2002 to 2010
Real growth (PWR)	-1.06 % to 0.76%
Real growth (BWR)	-1.07% to -0.45%

In view of the actual performance of NDTs compared to decommissioning cost escalation, if the discounting is allowed, the licensee would need to justify its assumptions regarding the real rate

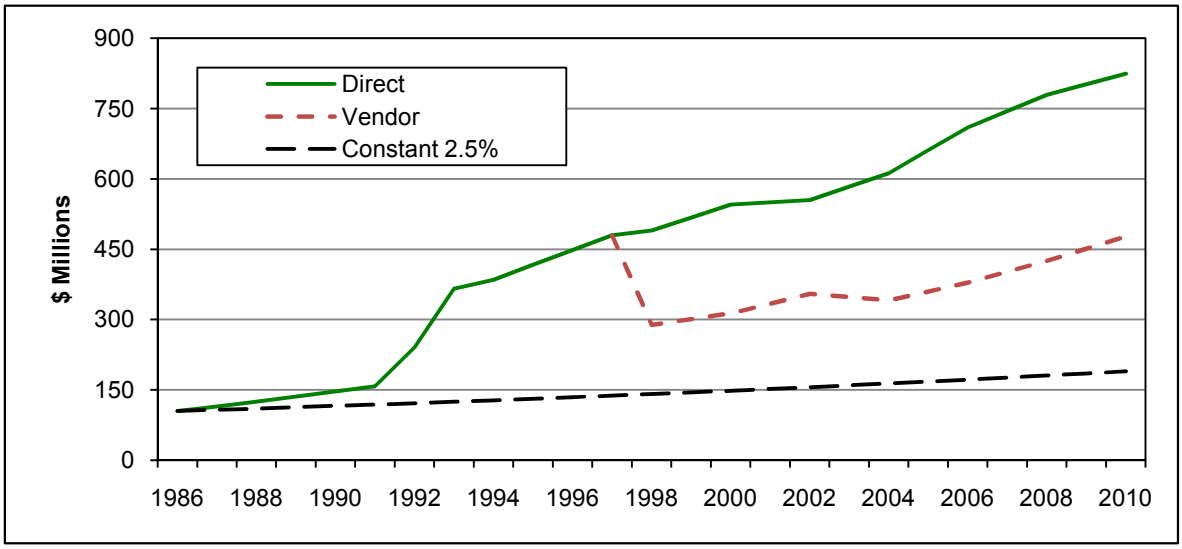
Plant, Unit Nos. 1 and 2; Calvert Cliffs Independent Spent Fuel Storage Installation, Nine Mile Point Nuclear Station, Unit Nos. 1 and 2; and R.E. Ginna Nuclear Power Plant, p.18, October 30, 2009 (ML093010003)

[117] BGE 2006 Letter, p.3

[118] ABZ, Inc., Current Decommissioning Issues, June 17, 2011 (ML111740054)

of return, under the specific circumstances of its submittal, rather than simply assume a 2% discount rate.

NRC Formula Amounts by Year – Large PWR



The chart labeled, "NRC Formula Amounts by Year – Large PWR," compares historical decommissioning costs calculated by ABZ, Inc., based on data from NUREG-1307, with a typical cost escalation rate.[119] The "Direct" line is the amount calculated from the prescribed amount specified in § 50.75(c). The "Vendor" amount is an adjustment to the prescribed amount introduced in 1998. It recognizes the potential savings that may be available from using waste processing techniques provided by specialized vendors. The "Constant 2.5%" line is a typical cost escalation assumption observed by ABZ, Inc. in its review of decommissioning cost estimates made by licensees. The negative real rates of growth calculated by ABZ, Inc. in the table above titled, "Average After-Tax Annual Growth Rate of NDTs Compared to Decommissioning Cost Escalation Rate," indicate that the rising costs of decommissioning have outpaced NDT fund growth over the last decade.

Effect of 2008 Market Downturn

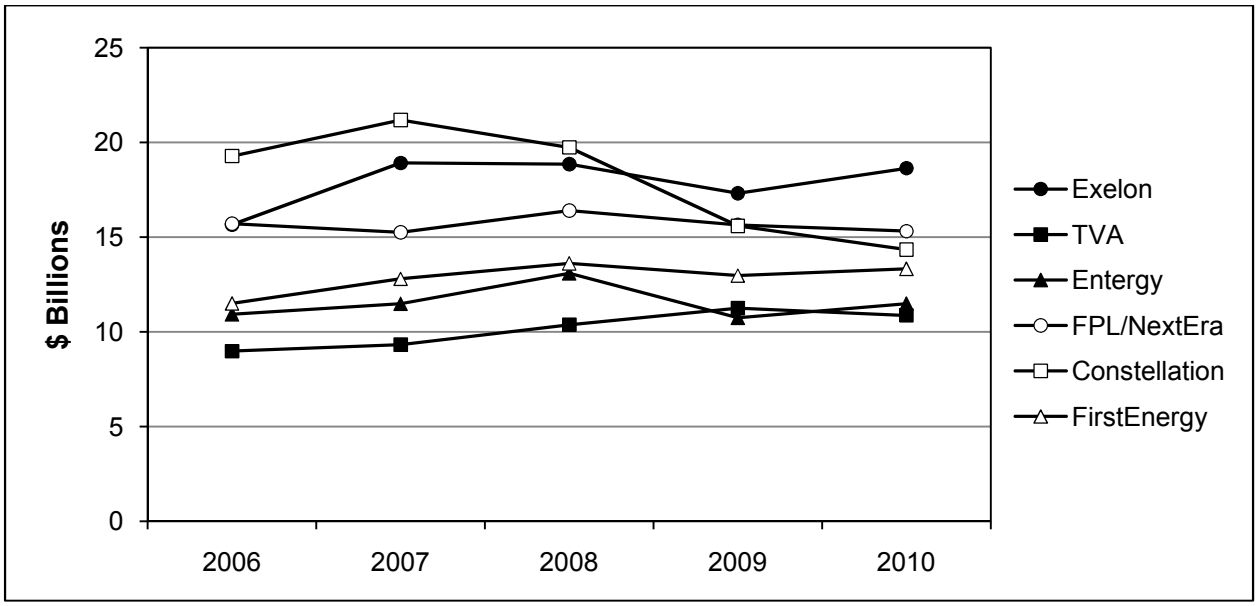
The financial performance of the six parent companies that owned reactor licensees that reported shortfalls in decommissioning financial assurance in March 2009 is shown in the following four charts. As seen in the charts, their financial performance did not change much during the recession of 2008 – 2009, with the exception of Constellation Energy Group. Constellation experienced large losses in its energy trading program in 2008, and sold a substantial interest in its nuclear business to Èlectricitè de France in 2009.

Total Revenue is the consolidated value of all sales made by the parent company and its subsidiaries. Net Income is the residual income after adding revenues and gains and subtracting expenses and losses during the period. Total Common Shareholder's Equity represents the stockholders' claim to a business' assets after all creditors and debts have been paid; it is also known as net worth. However, because the Tennessee Valley Authority is a government corporation without shareholders, the total proprietary capital recorded on the

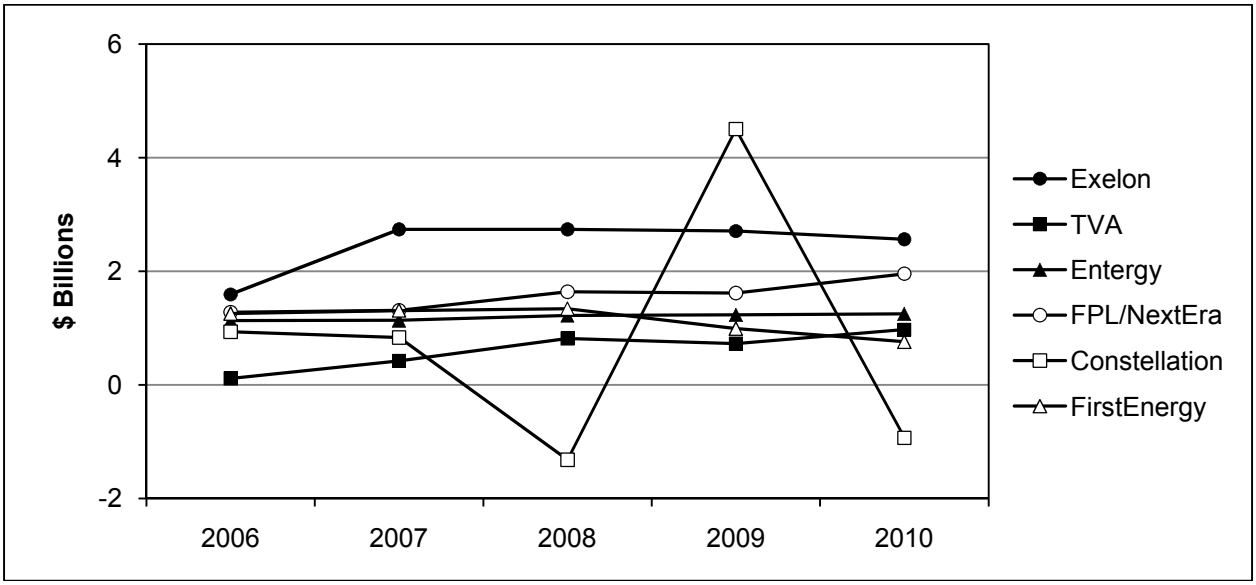
[119] ABZ, Inc., Cost Trends in Decommissioning, March 2, 2011 (ML110560598)

balance sheet is used in place of shareholder's equity. Net cash – Year End Balance is the amount of cash on hand held by the company at the end of its fiscal year.

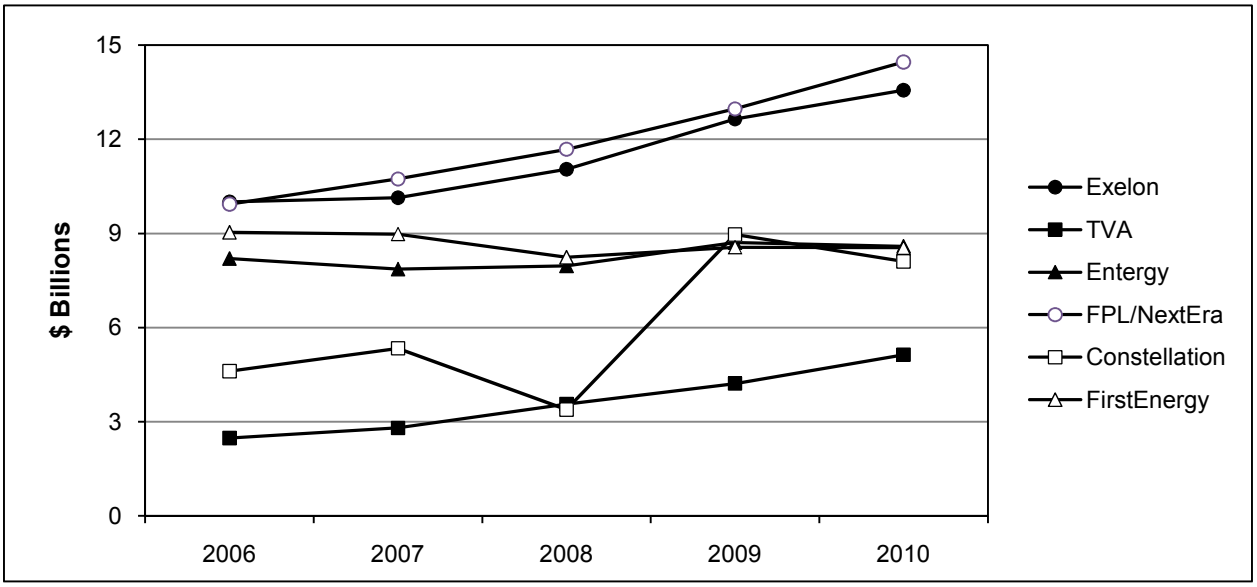
Total Revenue by Year



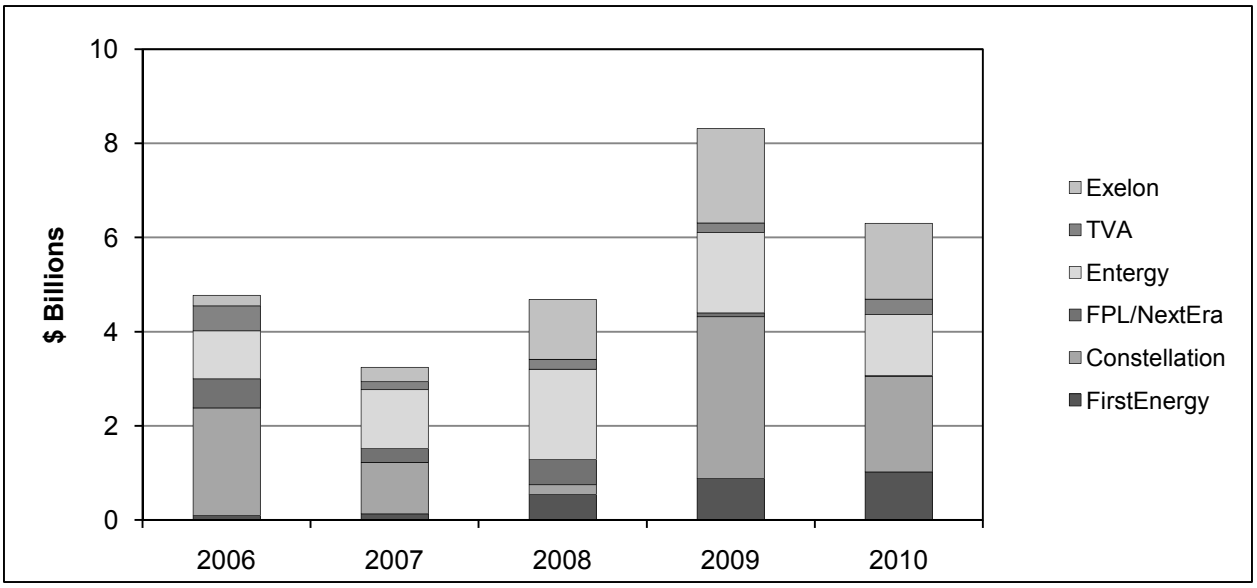
Net Income by Year



Total Common Shareholder's Equity by Year



Net Cash – Year End Balance



PROBABILITY INSIGHTS

The March 2011 workshop provided insights regarding the probability of large shortfalls, given historical trends in investment performance, NDT fund contributions, and the rate of escalation in decommissioning costs.

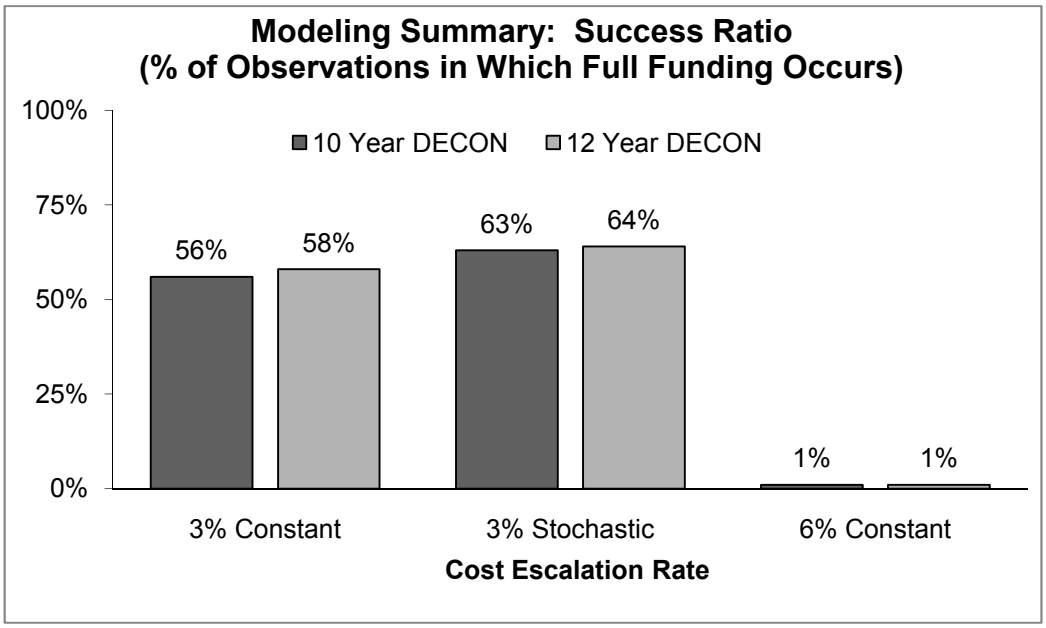
Dr. Daniel Williams presented information showing that the rate of return on investments and the rate of escalation in decommissioning costs are the two most important variables affecting the success of funding the cost of decommissioning. LCG Associates, Inc. presented a model

showing how cost escalation can affect the success of a NDT with a shortfall, while holding the investment strategy steady. GAO presented its study of how market volatility can reduce the ability of a trust fund to meet its funding target.

LCG Associates, an investment advisor for NDT funds, uses Monte Carol methods to estimate the probability to success for its clients. The Monte Carlo model uses a distribution of investment returns to estimate the return on investment. The investment returns distribution is based on historical data. The model is run thousands of times to generate a probability distribution of possible outcomes. In contrast to the Monte Carlo technique, the NRC method computes a single outcome.

The chart titled, "Success Ratio of NDT with No Contributions," displays the results of LCG Associates' Monte Carlo analysis that a hypothetical NDT with a shortfall will achieve its goal of full funding of decommissioning.[120] The NDT is assumed to have $345 million against a decommissioning cost of $600 million. The plant has 22 years of life remaining. The plant will be decommissioned immediately after shutdown, and will take either 10 years or 12 years to complete the project. The 3% constant rate approximates the general inflation rate. The 3% stochastic rate considers the correlation between investment returns and general inflation. The 6% rate approximates the lower range of decommissioning cost escalation. The funds are assumed to be professionally managed and to experience historically observed growth rates and volatility. The model illustrates a significant probability of unfunded costs under the general inflation assumption, and a very significant probability of unfunded costs when actual decommissioning cost escalation is considered. No funds are added to the NDT in the model. The implication is that using the PCG to delay or cease making contributions to the NDT may significantly raise the probability that large unfunded decommissioning cost obligations will occur, because the PCG does not produce any actual cash return.

Success Ratio of NDT with No Contributions



[120] LCG Associates, Nuclear Decommissioning Trust Asset/Liability Modeling, March 2, 2011 (ML110560778)

The chart provides some insight to the likelihood that investment returns will be sufficient, without making NDT contributions, where the NDT has a shortfall, to provide funds when needed for decommissioning. Under the Monte Carlo method, the probability of success varies from about 56% to 64%, when compared to a proxy for the general inflation rate (3% Constant, and 3% Stochastic). That implies about a 1 in 3 chance of not meeting the funding target. When compared to a proxy for the escalation rate of decommissioning costs (6% Constant), the probability of success declines to 1%. The chance of not meeting the funding target is about 99 in 100 in the higher cost escalation case.

LCG Associates also estimated the distribution of surpluses and shortfalls for the hypothetical fund for each scenario. The distribution results are shown in the table labeled, "Surplus or Shortfall of Funding in Monte Carlo and NRC Methods." For comparison, results of the NRC evaluation method were applied to the hypothetical facts and included in the table. The "Median" column shows the funding level where half the results are above the value, and half below. The "2.5th Percentile" column shows the results at the lower end of the distribution; it can be thought of as the "worst case" result.

For comparison, the NRC evaluation method of LIC-205 was applied to the hypothetical facts used for the Monte Carlo model. The NRC's evaluation of funding adequacy does not provide an estimate of the probability of success.[121] NRC considers a single scenario, based on the assumption of a constant 0% cost escalation rate, that is, no cost increases. The NRC allows up to a 2% real rate of return on investments, without any adjustments for market volatility. As seen in the table, using the NRC method shows the hypothetical NDT has shortfall.

Surplus or Shortfall of Funding in Monte Carlo and NRC Methods

Cost Escalation Rate	Monte Carlo Surplus or Shortfall (-)		NRC Shortfall (-)
	Median	2.5th Percentile	Single Scenario
10 Year DECON			
0% Constant	n.a	n.a	-$73 million
3% Constant	$17 million	-$118 million	n.a
3% Stochastic	$31 million	-$107 million	n.a
6% Constant	-$310 million	-$431 million	n.a
12 Year DECON			
0% Constant	n.a.	n.a.	-$50 million
3% Constant	$22 million	-$120 million	n.a
3% Stochastic	$36 million	-$108 million	n.a
6% Constant	-$327 million	-$450 million	n.a

In this example, the NRC result falls below the median when the cost escalation rate is moderate. When the rate of cost escalation is higher, the NRC result falls above the median and significantly underestimates the shortfall.

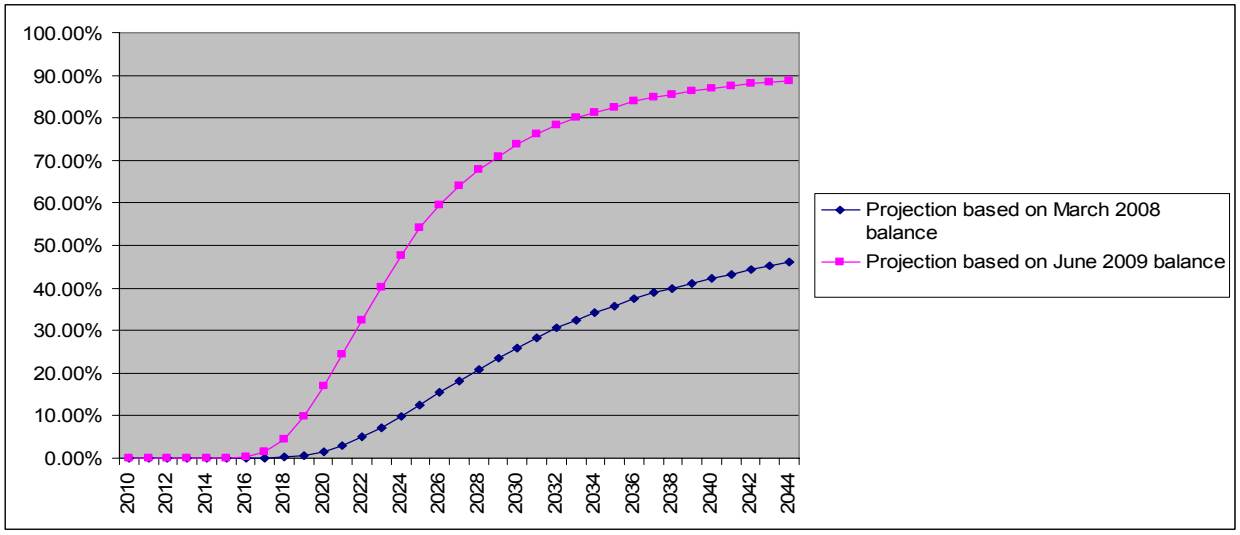
[121] SECY-10-0084, Enclosure 2, "Response to Comments on Draft Guidance DG-1229, 'Assuring the Availability of Funds for Decommissioning Nuclear Reactors,'" discusses the NRC evaluation method for funding assurance at p.6 - 4 and p.36 – 41. (ML101540488)

Some insight into the effect of a longer time horizon can be seen in the table. The deterministic model used by NRC is expected to show lower shortfalls for longer time horizons, due to its implicit assumption that investment return will outpace cost escalation. That result is seen in the table. The Monte Carlo method shows the opposite result. In cases where shortfalls occur, adding time to the investment horizon actually increases the size of the shortfall.

The enclosed table on Nuclear Decommissioning Cost Estimates and Cost Escalation Rates shows that decommissioning costs have risen between 4.7% and 9.0% per annum since 1986. Considering the cost escalation rates in the table suggests that the Monte Carlo model results for the 6% constant cost escalation rate may be more representative of future cost trends. That conclusion suggests that the size of shortfalls, for cases where the licensee delays or ceases making contributions to its NDT, are likely to be higher than estimated with the NRC method.

The GAO's presentation illustrated that longer time horizons can increase the risk of shortfalls when no funds are added to the NDT.[122] GAO performed a Monte Carlo analysis of a trust fund set up by the United States Government to provide economic assistance to the Republic of Palau. The results are shown in the chart labeled, "Probability of Shortfall in Trust Fund Given Market Volatility." A deterministic calculation showed that the trust fund would meet its goals even if its investment returns lagged slightly behind its historical average. However, when the effect of market volatility was factored into the evaluation, a significant risk was observed in the ability of the trust fund to meet its goals. Also significant is the observation that the risk of shortfalls increased with time. The implication for reactor DFA is that using SAFSTOR to project larger earnings credits under the NRC's deterministic rules may mask an increased the risk of shortfalls due to market volatility. The results of the analysis are shown in the chart below. If withdrawals are necessary at a time when the investments have lost value, the depleted balance may be unable to catch up. That is relevant to SAFSTOR evaluations, since paying the costs to maintain safe storage cannot be delayed, and may require NDT withdrawals to maintain safety.

Probability of Shortfall in Trust Fund Given Market Volatility



[122] GAO, Analyzing Uncertainty Using Monte Carlo Simulation, March 2, 2011 (ML11060025)

While market volatility produces risks to decommissioning funding success on its own, the effects can be compounded when the cost escalation is also high. Recall the ABZ Inc. estimates above, showing that the real rate of return has been negative in many cases. The cost escalation rate of decommissioning, as measured by NUREG-1307, ranges from 6% to 9% per year. The volatility risk and cost escalation risk synergistically raise the risk that shortfalls will occur if no contributions are made to the NDT.

In summary, the probability insights provided by the models suggest the following factors that should be considered when evaluating a discounted PCG:

- Real rate of return
- Cost escalation
- Market Volatility
- Delay or cessation of NDT contributions

NUCLEAR DECOMMISSIONING COST ESTIMATES AND COST ESCALATION RATES as of December 2010

Labor Region	Reactor	Compact	Burial Contract	Cost ($MM)	Compound Growth (%)	% Change '09-'10 (%)
Northeast	PWR	Atlantic	Direct	828.5	9.0	7.1
Northeast	PWR	Atlantic	Waste Vendor	481.8	6.6	15.1
Northeast	PWR	Non-Atlantic	Direct	828.5	9.0	7.1
Northeast	PWR	Non-Atlantic	Waste Vendor	481.8	6.6	15.1
Northeast	BWR	Atlantic	Direct	979.1	8.6	7.1
Northeast	BWR	Atlantic	Waste Vendor	628.1	6.6	8.7
Northeast	BWR	Non-Atlantic	Direct	979.1	8.6	7.1
Northeast	BWR	Non-Atlantic	Waste Vendor	628.1	6.6	8.7
South	PWR	Atlantic	Direct	813.5	8.9	7.2
South	PWR	Atlantic	Waste Vendor	466.8	6.4	15.5
South	PWR	Non-Atlantic	Direct	813.5	8.9	7.2
South	PWR	Non-Atlantic	Waste Vendor	466.8	6.4	15.5
South	BWR	Atlantic	Direct	959.8	8.5	7.2
South	BWR	Atlantic	Waste Vendor	608.8	6.5	8.8
South	BWR	Non-Atlantic	Direct	959.8	8.5	7.2
South	BWR	Non-Atlantic	Waste Vendor	608.8	6.5	8.8
Midwest	PWR	Non-Atlantic	Direct	819.7	8.9	7.3
Midwest	PWR	Non-Atlantic	Waste Vendor	472.9	6.5	15.6
Midwest	BWR	Non-Atlantic	Direct	967.7	8.6	7.3
Midwest	BWR	Non-Atlantic	Waste Vendor	616.7	6.5	9.0
West	PWR	Non-Atlantic	Direct	819.7	8.9	7.1
West	PWR	Non-Atlantic	Waste Vendor	472.9	6.5	15.2
West	PWR	Northwest	Direct	374.8	5.4	0.3
West	PWR	Northwest	Waste Vendor	341.4	5.0	13.3
West	BWR	Non-Atlantic	Direct	967.7	8.6	7.1
West	BWR	Non-Atlantic	Waste Vendor	616.7	6.5	8.7
West	BWR	Northwest	Direct	464.7	5.3	-49.7
West	BWR	Northwest	Waste Vendor	406.4	4.7	-52.5

Source: Historical NDT Fund Balances, Annual Contributions and Decommissioning Cost Estimates, Duff & Phelps Investment Management Company, March 2, 2011 (ML110690037)

Notes:
1. Cost calculated by Duff & Phelps, based on data from NUREG-1307, Vol. 14, "Report on Waste Burial Charges"
2. Compound Growth = Annualized % change over 24 years from 1986 Base Cost, calculated by Duff & Phelps