POLICY ISSUE
INFORMATION

June 25, 2010 SECY-10-0084

FOR: The Commissioners

FROM: Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

SUBJECT: EXPLANATION OF CHANGES TO REVISION 2 TO REGULATORY GUIDE 1.159, "ASSURING THE AVAILABILITY OF FUNDS FOR DECOMMISSIONING NUCLEAR REACTORS"

PURPOSE:

On March 25, 2010, the U.S. Nuclear Regulatory Commission (NRC) issued Staff Requirements Memorandum (SRM) M100223B, "Briefing on Decommissioning Funding," directing the staff to provide the Commission with an information paper explaining the changes to the final Regulatory Guide (RG) 1.159, Revision 2, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," and allowing appropriate time to receive Commission direction, if the Commission is so inclined, before issuance of the regulatory guide. This information paper provides the staff response.

SUMMARY:

The NRC issued draft guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," in June 2009 to gather public comments on proposed changes to three sections of regulatory guidance that the agency would ultimately issue as RG 1.159, Revision 2. In addition to updating references, the changes would (1) increase the frequency of covering a shortfall in decommissioning financial assurance (the merchant plant licensee frequency would be increased from 2 years to 1 year and the utility licensee frequency would be increased from every 6 years to every rate case) and remove a statement on using

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a reasonable time to make up a deficit, (2) clarify when a real rate of return greater than 2 percent may be credited, and (3) clarify that the earnings credit allowed during a safe storage period following permanent shutdown must reflect any withdrawals needed to maintain the facility in safe storage.

The staff received comments opposing the increased frequency of adjustments. No comments were received on the other 2 proposed changes, which simply document existing staff practice.

The staff concluded that RG 1.159, Revision 2 should include the unopposed changes to clarify the 2 percent return and the earnings credit during safe storage. Regarding the increase in adjustment frequency, the staff evaluated the cost of covering a shortfall within 3 months of the annual escalation adjustment of the minimum amount done on December 31, as required under Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.75(b). The staff found that the commenter's assertions of undue financial burden were contradicted by a number of sources, including financial reports published by parent company owners of reactor licensees. The staff determined that RG 1.159, Revision 2 should include guidance for merchant plant licensees to adjust the actual amount of financial assurance annually, as of March 31 of each year, based on the escalated amount calculated as of the previous December 31. The staff determined that utility licensees would not have to address decommissioning funding in every rate case, but should make a good faith effort to obtain rate relief by requesting their rate regulator to address the issue within the year, and to obtain rate relief as necessary within 5 years.

BACKGROUND:

All power reactor licensees are required to report the status of their decommissioning funds biennially on March 31 of each odd numbered year.[1] Where the amount of financial assurance provided by the licensee is less than the amount required by the regulation, the difference is termed the "shortfall." The NRC now has experience with two equity market downturns, in 2003 and 2009, in which a number of power reactor licensees reported shortfalls.[2] The existing guidance of RG 1.159, Revision 1 states that a merchant plant licensee should make needed adjustments in the level of financial assurance every 2 years, in conjunction with the decommissioning fund status report. For public utility licensees, the existing guidance states that they should obtain rate relief within 6 years.

The NRC issued draft guidance DG-1229 in June 2009 to gather public comments on proposed changes in regulatory guidance. A public meeting held on August 20, 2009, drew over 100 participants to discuss the draft guidance. The Nuclear Energy Institute (NEI) provided extensive written comments, by the end of the comment period in September 2009, which were supported by four industry stakeholders. The comments objected to reducing the time available to cover a shortfall. The comments suggested using case-by-case negotiation without time limits as an acceptable method to resolve shortfalls, and that the NRC should accept net present value (NPV) methods to calculate the size of the shortfall. No comments were received on the proposed clarifications regarding the use of the 2-percent real rate of return or the earnings credit during a period of safe storage. No comments were received supporting the

[1] 10 CFR 50.75(f). The report is required annually for licensees involved in mergers or acquisitions; within 5 years of expected shutdown; or permanently shut down.

[2] The minimum amount is specified in 10 CFR 50.75(c), which includes a factor for inflation.

proposed changes. Beginning in summer 2009, the staff engaged in case-by-case negotiation with the 26 licensees who had not resolved their shortfalls in their March 2009 decommissioning fund status reports. As of May 2010, four merchant plant facilities (Braidwood 1 and 2, Byron 2, and River Bend) had not resolved their shortfalls. Over 1700 staff hours have been spent on resolving the shortfalls on a case-by-case basis.

The Commission held a public meeting to discuss decommissioning financial assurance on February 23, 2010. Following the meeting, the Commission issued SRM M100223B directing the staff to explain its reasoning for the proposed changes to RG 1.159, Revision 2.

DISCUSSION:

In concluding that existing NRC guidance should be changed to increase the frequency of adjusting financial assurance for decommissioning to annually, the staff considered two major issues.

First, the Commission has often stated that licensees must provide timely and adequate financial assurance for decommissioning costs.[3] The Commission also stated that a licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[4] These statements imply that shortfalls, should be avoided where possible and, if they occur, should be covered in a timely manner.

Licensee Performance in Response to Equity Market Declines[5]

Reporting Year	Market Decline from Previous Report	Number of Facilities with Shortfalls	Shortfalls Resolved in 3 Months	Shortfalls Not Resolved in 1 Year
2003	-23%	9	3	0
2009	-30%	27	1	6

Second, the NRC last considered annual adjustments in 2002. Since then, changed circumstances indicate that reconsideration is warranted. The table above summarizes licensee performance in response to the 2003 and 2009 equity market declines. In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that corrected their shortfalls in 3 months decreased in 2009, although a greater number needed to make corrections.

3 See the following: 53 FR 24030–24031 and 24033, 56 FR 41493, 57 FR 30395, and 67 FR 78332.

4 See 61 FR 39278.

5 Decline calculated from Dow Jones Industrial Average Index closing price on December 31 of the relevant years

Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees did not resolve their shortfalls within 1 year of December 31, 2008. The licensees raised several issues that delayed resolution: 4 licensees claimed the staff should accept NPV methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. Comparing 2009 to 2003, the number of facilities with shortfalls increased by 18, of which 16 were merchant plants.[6] The staff concluded that (1) the data indicated an apparent trend toward less adequate and less timely financial assurance in response to an equity market decline, and (2) case-by-case negotiation with each licensee to resolve a shortfall appeared to be less effective in 2009.

The timing and severity of market fluctuations are outside licensee control. However, licensees have the ability to make forward-looking plans to account for the inescapable volatility of the markets. Licensees can control a variety of measures to manage financial risks.[7] Three-fourths of power reactors avoided shortfalls in 2009, thus demonstrating that successful forward-looking plans are available.

Licensees can also control their response to a shortfall, if it occurs. For example, following the 2002 equity market decline, Progress Energy provided PCGs totaling $276 million to supplement financial assurance at three of its public utility reactor facilities within 3 months of the end of the decommissioning fund status reporting period. Its action demonstrate that a licensee can cover a substantial shortfall within 3 months without suffering the adverse effects asserted by comments submitted in opposition to the proposed annual frequency for covering shortfalls.

The staff considered periods of 1 to 3 years for the frequency of adjustments to cover shortfalls. The staff determined, based on experience with the Connecticut Yankee (CY) facility, that allowing 3 years to resolve a shortfall could increase the risk that a licensee would lack adequate funds to complete decommissioning. CY was a regulated electric utility. In CY's case, the licensee conducted periodic market studies to determine the economic viability of the plant. Unfortunately, CY's outlook reversed from viable to nonviable within 3 years as the result of price competition. A decrease in competitive prices of about 7 percent resulted in a decision to immediately shut down the plant and begin decommissioning. When the shutdown occurred, CY's rate collections had not yet accumulated adequate funds for decommissioning.[8] CY was able to pay for decommissioning because of its status as an electric utility with access to several hundred million dollars in additional ratepayer funds, after going through contentious rate proceedings.

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6 In 2003, the total included 8 utility facilities and 1 merchant facility, In 2009, the total included 9 public utility facilities, 16 merchant plant facilities, and 2 facilities that were "hybrids," with both utility and merchant licensee owners.

7 For instance, licensees control how much exposure to market risk they will accept when they give instructions to their fund managers. They can increase or decrease their reliance on future earnings to pay for decommissioning. They can arrange to obtain guarantees to cover shortfalls before the fact, at favorable rates, or choose to wait until after the fact and face potentially higher rates. They can choose to maintain a higher fund balance to withstand volatility or a lower balance that is vulnerable to volatility.

8 The regulations do not require licensees to possess the full amount of cash needed for decommissioning until the time of permanent shutdown. However, licensees must provide financial assurance that they can obtain the funds at any time during the life of the facility. *See* footnotes 3 and 4, *supra*.

However, the CY experience emphasizes the need for full up-front financial assurance from a merchant plant licensee that has no access to ratepayer funds to cover shortfalls, but faces at least equal competitive pressures.

The staff considered the 2-year frequency to be a suboptimal adjustment frequency. First, the 2-year frequency appears to be getting less effective in encouraging licensees to make forward-looking plans to avoid shortfalls. Second, if a merchant plant delays covering the shortfall for over a year, as happened in several cases in 2009, the 2-year period can extend beyond 3 years.

The staff found that the cost of covering a shortfall on an annual basis is minimal using a PCG and is a very small percentage of net income using other guaranty methods. Annual adjustment of the actual amount of financial assurance provided would encourage licensees to use forward-looking plans to avoid shortfalls, and would align with the Commission's policy that licensees are required to provide adequate financial assurance at any time during the life of the facility. The adjustment of the actual amount provided would coincide with the existing requirement to make an annual escalation adjustment to the minimum requirement, as required by the provisions of 10 CFR 50.75(b)(2) and (c)(2).

The staff considered the comments received on the draft guidance of DG-1229. As noted in the Progress Energy example, the commenter's assertions of undue financial burden are contradicted by actual licensee experience. The staff found that NEI did not adequately consider the effects of equity market volatility on the ability of a licensee to provide funds when needed for decommissioning when relying on market gains to cover future expenses. The enclosure provides details of the staff's consideration of the comments.

The staff declined the suggestion to provide guidance recommending case-by-case negotiation without time limits as a method to resolve shortfalls on the grounds that the Commission rejected the case-by-case approach to decommissioning financial assurance when it issued its 1988 Decommissioning Rule.[9]

The staff declined the suggestion to provide guidance recommending the net present value method for calculating the size of a shortfall on grounds that it underestimated the amount.

In view of the information summarized above, the staff concluded that the NRC's guidance should recommend an increased frequency for adjusting the level of financial assurance to cover a shortfall.

For merchant plant licensees, the guidance will state that the level of financial assurance should be adjusted to cover shortfalls annually, by March 31 of each year.

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9 See Volume 53, page 24019, of the Federal Register (53 FR 24019). However, in the case of prematurely shutdown reactors, the Commission concluded that a case-by-case approach was necessary. See 57 FR 30383, 30394. The Commission may also take actions as appropriate on a case-by-case basis to modify a licensee's schedule for the accumulation of decommissioning funds. See 10 CFR 50.75(e)(2).

For utility licensees, the NRC has a policy to minimize its involvement with the rate regulatory process.[10] However, a commenter requested that the staff include guidance on good-faith efforts to seek rate relief. Accordingly, the staff will include guidance for a utility licensee to inform its rate regulator by March 31 of each year when a shortfall occurs as of the preceding December 31 and request its rate regulator to review decommissioning cost recovery within the year.

The staff will continue its practice of monitoring the adequacy of financial assurance for decommissioning in conjunction with the decommissioning fund status report submitted by licensees. However, the staff may increase the frequency of its reviews, if necessary, under the provisions of 10 CFR 50.75(e)(2), which allow the NRC to review and take appropriate action with respect to decommissioning financial assurance, either independently or in cooperation with a licensee's rate regulator.

COORDINATION:

There are no resource implications in this paper. The Office of the General Counsel has reviewed this paper and has no legal objection.

/RA/

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Enclosures:
1. Summary of NRC Financial Assurance Requirements
2. Response to Comments on DG-1229
3. Staff Calculation Using 2 Percent Earnings
4. Licensee Calculation Using Net Present Value Methods
5. Proposed Changes to Final RG 1.159, Revision 2

10 See 53 FR 24030.

Summary of NRC Decommissioning Financial Assurance Requirements for Power Reactors

- Basic Objectives:
    1. Protect the public from the significant radiation hazard of non-decommissioned nuclear reactors (53 FR 24033)
    2. Assure that lack of funds does not delay safe and timely decommissioning (53 FR 24033)
        a. Full funding of decommissioning at the time of permanent shutdown (53 FR 24030-31, 56 FR 41493, 57 FR 30395, 67 FR 78332)
        b. A licensee is required to provide adequate financial assurance at any time during the life of the facility, through termination of the license (61 FR 39278)
    3. Provide flexibility in financial assurance methods (63 FR 50468)
    4. Minimize administrative effort required of the NRC and licensees to establish financial assurance (53FR 24030)
    5. Minimize NRC involvement with rate regulatory process (53 FR 24030)
    6. For merchant plants, full up-front financial assurance (63 FR 50469)
    7. Reserve the right to review and modify fund accumulation schedule (10 CFR 50.75(e)(2)

- The three step regulatory process before permanent shutdown (53 FR 24030-31) includes:
    1. Initial certification that minimum requirement has been provided
    2. Periodic adjustment for inflation
        a. Annual adjustment of minimum requirement in accordance with specified escalation rate (10 CFR 50.75(b)(2) and (c)(2))
    3. Site-specific cost estimate 5 years prior to permanent shutdown

- Minimum requirement for decommissioning financial assurance (10 CFR 50.75(c)(1) and (2)):
    1. Formula in 1986 dollars:
        a. PWR millions = $(75 + 0.0088*MWt), max. $105
        b. BWR millions = $(104 + 0.009*MWt), max. $135
    2. Escalation = 0.65 L + 0.13 E + 0.22 B, factors published in NUREG-1307

- Criteria for evaluating funding methods (50 FR 5607-08):
    1. Most important: degree of assurance
    2. Important: cost of providing assurance

- Periodic monitoring using decommissioning fund status report (10 CFR 50.75(f))

- Methods available for providing financial assurance for decommissioning (10 CFR 50.75(e)):
    1. Funds held in trust, including projected earnings at up to 2% annually, or higher rate if authorized by the licensee’s rate regulator
    2. Guaranty methods:
        a. Letter of credit
        b. Surety or insurance
        c. Parent company guarantee & self-guarantee
    3. Contractual obligations, if adequate guarantee of payment is included
    4. Statements of intent, if a government licensee
    5. Combinations of above and other methods proposed by licensee, if they provide equivalent degree of assurance

Response to Comments on Draft Guidance DG-1229,

“Assuring the Availability of Funds for Decommissioning Nuclear Reactors”

Response to Comments on Draft Guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors"

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Executive Summary

In concluding that guidance on the frequency of adjusting financial assurance for decommissioning should be increased to annually, the staff of the U.S. Nuclear Regulatory Commission (NRC) considered two major issues.

First, the Commission has often stated that licensees must provide timely and adequate financial assurance for decommissioning costs.[1] The Commission has also stated that a licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[2] These statements imply that shortfalls, which are occasions when the licensee's financial assurance does not meet the regulatory minimum requirement, should be avoided where possible and, if they occur, should be covered in a timely manner.

Second, the NRC last considered annual adjustments in 2002. Since then, as noted below, the timeliness and adequacy of license response to covering shortfalls has apparently decreased. These changed circumstances indicate that reconsideration is warranted.

The staff compared licensee performance in covering shortfalls in decommissioning financial assurance in response to the 2003 and 2009 equity market declines. Where the licensee provides financial assurance in an amount less than the amount required by regulation, the difference is termed the "shortfall." In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that took self-initiated action to correct their shortfalls decreased in 2009, although a greater number needed to make corrections. Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees took over a year to resolve their shortfalls. The licensees raised several issues that delayed resolution: 4 licensees claimed the staff should accept net present value methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. The staff concluded that (1) the data indicated an apparent trend toward less adequate and less timely financial assurance in response to an equity market decline and (2) case-by-case negotiation with each licensee to resolve a shortfall appeared to be less effective in 2009.

The NRC issued draft guidance DG-1229, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," in June 2009 to gather public comments on proposed changes to three sections of regulatory guidance that the agency would ultimately issue as RG 1.159, Revision 2. In addition to updating references, the changes would (1) increase the frequency of covering a shortfall in decommissioning financial assurance (the merchant plant licensee frequency would be increased from 2 years to 1 year and the utility licensee frequency would be increased from every 6 years to every rate case) and remove a statement on using a reasonable time to make up a deficit, (2) clarify when a real rate of return greater than 2 percent may be credited, and (3) clarify that the earnings credit allowed during a safe storage period

1 See the following *Federal Register* (FR) notices: 53 FR 24030–24031 and 24033, 56 FR 41493, 57 FR 30395, and 67 FR 78332.

2 See 61 FR 39278.

following permanent shutdown must reflect any withdrawals needed to maintain the facility in safe storage.

No comments were received on the proposed changes to clarify the use of the 2-percent real rate of return or the earnings credit during a period of safe storage. The Nuclear Energy Institute (NEI) opposed the increased frequency of adjusting the amount of financial assurance to cover a shortfall for a variety of reasons, primarily based on cost. Additional objections were raised that (a) the guidance had no safety benefit, (b) a notice-and-comment process should have been used to change the guidance, (c) the successful history of funding reactor decommissioning rendered changes unnecessary, and (d) the long investment horizon to accumulate funds provided additional assurance that funds would be available, based on the low probability that any currently operating reactor will be decommissioning in the next several decades. The comments objected to the methods used by NRC to calculate the amount of a shortfall in financial assurance provided by a licensee. The comments suggested that (a) licensees should be permitted to resolve shortfalls using case-by-case negotiations without time limits, (b) rate-regulated licensees should not be requested to address decommissioning funding in every rate case, and (c) that guidance should be provided on making a good faith effort to address shortfalls in ratemaking proceedings. A comment suggested updating references in the guidance. Four industry stakeholders submitted comments expressing support of NEI's comments. No comments were received supporting the proposed changes.

The Nuclear Energy Institute (NEI) noted that the NRC's long-standing position has been to handle the frequency of adjustments to decommissioning funding in guidance. NEI nevertheless objected to the proposed guidance on grounds that the draft guidance interpreted the NRC's regulations in a new way. The staff concluded that NEI's objection was not persuasive on grounds that the proposed guidance to cover shortfalls annually is within the scope of the Commission's long-standing policy that the licensee is required to provide assurance at any time during the life of the facility.

The staff concluded that the commenters overestimated the costs of covering a shortfall. The staff evaluation found that covering a shortfall with a parent company guarantee had essentially no cost and using a letter of credit or a surety was a very small percentage of the net income earned by the licensees. In view of the flexibility of the NRC's financial assurance methods, the staff concluded that the cost of covering a shortfall was not an undue financial burden.

The commenters argued that the expected long time horizon before decommissioning is likely to be necessary would justify a delay in covering a shortfall. The staff disagreed for several reasons. For example, the staff reviewed annual reports to shareholders and to the Securities and Exchange Commission prepared by parent companies that own power reactor licensees. Those reports identified significant costs to the companies in the event that the decommissioning trust funds underperformed over a period of time. The staff concluded that excessive reliance on market growth could delay decommissioning due to lack of funds. The staff also concluded that an expectation of market growth in excess of the 2-percent real rate of return provided in NRC regulations did not justify a delay in covering a shortfall. In addition, as noted above, the Commission's policy requires licensees to provide adequate financial assurance at any time during the life of the facility, and the cost, if any, to cover a shortfall falls within the range contemplated in the decommissioning rule.

The staff found that a 3-year frequency for adjusting financial assurance for decommissioning could increase the risk that funds would not be available when needed for decommissioning, based on experience with the Connecticut Yankee plant. In that case, the licensee's business outlook reversed from viable to nonviable in a 3-year period, which led to a decision to immediately and permanently shut down the plant. The 2-year frequency was apparently becoming less effective, as evidenced by the trend observed between 2003 and 2009 in the decommissioning fund status reports. The staff concluded that adjusting the level of assurance on an annual basis was optimal due to low cost and the reduction in the likelihood that decommissioning would be delayed because of a lack of funds. The annual frequency would apply to all licensees. The adjustment of the actual amount provided would coincide with the existing requirement to make an annual escalation adjustment to the minimum requirement, as required by the provisions of 10 CFR 50.75(b)(2) and (c)(2).

The commenter suggested that licensees be permitted to use case-by-case negotiation without time limits to resolve a shortfall. In 2009, over 1,700 staff hours were spent in case-by-case negotiation to resolve shortfalls reported by 27 licensees. The staff declined the commenter's suggestion on the grounds that the Commission had rejected the case-by-case approach to decommissioning in its 1988 Decommissioning Rule in order to minimize the administrative burden on the agency and the licensees.[3]

The commenter suggested that licensees should be permitted to use net present value (NPV) methods to calculate the size of a shortfall. The staff declined this suggestion on the grounds that NPV methods can underestimate the size of a shortfall.

The commenter suggested that guidance should be provided on using good-faith efforts by electric utility licensees to obtain rate relief. The staff agreed. The staff will include guidance for a utility licensee to inform its rate regulator by March 31 of each year when a shortfall occurs as of the preceding December 31 and request that its rate regulator review decommissioning cost recovery within the year.

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[3] 53 FR 24019

Introduction

In coming to the conclusion that guidance on the frequency of adjusting financial assurance for decommissioning should be revised from 2 years to 1 year for merchant plant licensees, the staff of the U.S. Nuclear Regulatory Commission (NRC) considered two major issues. First, the Commission often stated that licensees must provide timely and adequate financial assurance for decommissioning costs.[1] The Commission has also stated that adequate funds to complete decommissioning must be available at any time during the life of the facility, through termination of the license.[2] These statements imply that shortfalls, which are occasions when the licensee's financial assurance does not meet the regulatory minimum requirement, should be avoided where possible and, if they occur, covered in a timely manner.

Second, the NRC last considered annual adjustments in 2002. Since then, changed circumstances indicate that reconsideration is warranted. Table 2, presented in the discussion of Comment 5, "Case-by-Case Negotiation," summarizes licensee performance in response to the 2003 and 2009 equity market declines. In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that took self-initiated action to correct their shortfalls decreased in 2009, although a greater number needed to make corrections. Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees took over a year to resolve their shortfalls. The licensees raised several issues that delayed resolution: 4 licensees claimed the staff should accept NPV methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. The staff concluded that (1) the data indicated an apparent trend to less adequate and less timely financial assurance in response to an equity market decline and (2) case-by-case negotiation with each licensee to resolve a shortfall appeared to be less effective in 2009.

The timing and severity of market fluctuations are outside licensee control. However, licensees have the ability to make forward-looking plans to account for the inescapable volatility of the markets. Licensees can control a variety of measures to manage financial risks. Three-fourths of power reactors avoided shortfalls in 2009, which demonstrates that successful forward-looking plans are available.

Licensees can also control their response to a shortfall, if it occurs. The staff reviewed a case in which a parent company with three power reactor facilities had shortfalls in the 2002 equity market decline. The parent company provided guarantees to supplement the licensee's financial assurance within 3 months of the end of the fund status reporting period on December 31.

The staff considered periods of 1 to 3 years for the frequency of adjustments to cover shortfalls. The staff determined, based on experience with Connecticut Yankee (CY), that allowing 3 years to resolve a shortfall could increase the risk that a merchant plant licensee would lack adequate funds to complete decommissioning. In CY's case, the licensee conducted periodic market studies to determine the economic viability of the plant. Unfortunately, CY's outlook reversed

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[1] See the following *Federal Register* (FR) notices: 53 FR 24030–31 and 53 FR 24033, 56 FR 41493, 57 FR 30395, and 67 FR 78332.

[2] 61 FR 39278.

from viable to nonviable within 3 years due to price competition. A decrease in competitive prices of about 7 percent resulted in a decision to immediately shut down the plant and begin decommissioning. CY was able to pay for decommissioning due to its status as an electric utility with access to several hundred million dollars in additional ratepayer funds. A merchant plant faces at least equal competitive pressures, but has no access to ratepayer funds to cover shortfalls in its decommissioning funding.

The staff considered a 2-year frequency to be a suboptimal adjustment frequency. First, the 2-year frequency appears to be less effective in encouraging licensees to make forward-looking plans to avoid shortfalls. Secondly, if a merchant plant delays covering the shortfall for over a year, as happened in several cases in 2009, the 2-year period can extend beyond 3 years, thus increasing the risk that the licensee would lack funds to complete decommissioning.

On the other hand, the cost of covering a shortfall on an annual basis is minimal using a parent company guarantee (PCG) and reasonable using other guaranty methods. The staff concluded that covering a shortfall in 1 year would strengthen the licensee's ability to avoid a shortfall the next year. Covering shortfalls annually would not significantly increase costs, but would encourage licensees to use forward-looking plans to avoid shortfalls and would reduce the risk that a licensee would lack funds to complete decommissioning. The adjustment of the actual amount provided would coincide with the existing requirement to make an annual escalation adjustment to the minimum requirement, as required by the provisions of 10 CFR 50.75(b)(2) and (c)(2).

The staff considered the comments received on the draft guidance of DG-1229. The staff concluded that the commenter overestimated the cost of covering a shortfall, in part due to misreading the regulatory requirements for a PCG as stated in Appendix A, "Criteria Relating to Use of Financial Tests and Parent Company Guarantees for Providing Reasonable Assurance of Funds for Decommissioning," to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 30, "Rules of General Applicability to Domestic Licensing of Byproduct Material." The cost to cover a shortfall ranged from minimal to reasonable. The staff found that the commenter did not adequately consider the effects of equity market volatility and unpredictability on the ability of a licensee to provide funds when needed for decommissioning. However, a number of sources provided information on the potential adverse effects of market uncertainty that contradicted the commenter.

In view of the information currently available, the staff concluded that 1 year is the optimal frequency for merchant plants to adjust financial assurance to meet the regulatory requirement.

For utility licensees, the NRC has a policy to minimize its involvement with the rate regulatory process.[3] However, a commenter requested that the staff include guidance on good-faith efforts to seek rate relief. Accordingly, the staff will include guidance for a utility licensee to inform its rate regulator by March 31 of each year when a shortfall occurs as of the preceding December 31 and request its rate regulator to review decommissioning cost recovery within the year, and obtain rate relief as necessary within 5 years.

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[3] See 53 FR 24030.

Changes Proposed to Regulatory Guidance

The NRC issued draft guidance DG-1229, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors,” in June 2009 to gather public comments on a proposed change in regulatory guidance. Substantive changes were made in three sections: 1.3, “Decommissioning Cost Estimates”; Section 2.1.5 within Section 2.1, “Guidance Applicable to All Methods of Financial Assurance”; and Section 2.2.8 within Section 2.2, “Prepayment and External Sinking Fund.”

The changes within Section 1.3 added references to related regulatory guidance issued after Revision 1 to Regulatory Guide 1.159 was issued in 2003. The changes within Section 2.1.5 relate to a change in the frequency for making adjustments to the licensee’s financial assurance amounts and mechanisms. For merchant plants, the proposed frequency was increased from at least once every 2 years, in conjunction with the biennial report, to annually, at the end of each calendar year. For utility licensees, the proposed frequency was increased from once every 6 years to every rate case. Finally, changes were proposed to Section 2.2.8 to remove a statement on using a reasonable time to make up a deficit; clarify when greater than a 2-percent real rate of return may be credited; and state that the credit allowed during a safe storage period following permanent shutdown must reflect any withdrawals needed to maintain the facility in safe storage.

Description of Comments Received on Proposed Changes

The Nuclear Energy Institute (NEI) opposed the increased frequency of adjusting the amount of financial assurance to cover a shortfall for a variety of reasons, primarily based on cost. Additional objections were raised that (a) the guidance had no safety benefit, (b) a notice-and-comment process should have been used to change the guidance, (c) the successful history of funding reactor decommissioning rendered changes unnecessary, and (d) the long investment horizon to accumulate funds provided additional assurance that funds would be available, based on the low probability that any currently operating reactor will be decommissioning in the next several decades. The comments objected to the methods used by NRC to calculate a shortfall in the amount of financial assurance provided by a licensee. The comments suggested that (a) licensees should be permitted to resolve shortfalls using case-by-case negotiations without time limits, (b) rate-regulated licensees should not be requested to address decommissioning funding in every rate case, and (c) that guidance should be provided on making a good faith effort to address shortfalls in ratemaking proceedings. A comment suggested updating references in the guidance.

Two power reactor licensees submitted comments. The Tennessee Valley Authority (TVA) generally supported the NEI comments. Detroit Edison supported NEI’s comment that the guidance should not state that public utility licensees should address decommissioning funding at every rate case.

One power reactor organization, Strategic Teaming and Resource Sharing (STARS), supported several of the NEI comments. STARS made an additional comment that 3 months is too little time to address a shortfall.

One prospective transferee for a decommissioning power reactor license, EnergySolutions, supported several of NEI’s comments. EnergySolutions added that, for some licensees, the cost of a letter of credit (LOC) may be higher than NEI's estimates. EnergySolutions also added that, under strongly negative market conditions, such as occurred in 2008, the cost of an LOC can increase, and, perhaps, be unavailable at any price.

Changes Made in the Final Version of Regulatory Guidance

The annual frequency for adjusting the level of financial assurance was retained in Section 2.1.5 of RG 1.159. However, guidance on making a good-faith effort to obtain rate relief was added to Section 2.1.5. The guidance will instruct the licensee to inform its rate regulator when a shortfall occurs and to request that the rate regulator review decommissioning financial assurance within a year.

Definitions for "shortfall," and "decommissioning financial assurance" were added to the glossary of RG 1.159. "Shortfall" is discussed in the section titled, "NRC's Evaluation Method for Decommissioning Financial Assurance," of this paper. "Financial assurance" is discussed in Comment 15, "Cash Contributions Cause Overfunding," of this paper.

The revisions proposed for Section 1.3 and Section 2.2.8 were retained without change.

NRC's Evaluation Method for Decommissioning Financial Assurance

An important tool used by the staff to evaluate licensee financial assurance is the cash flow analysis. The cash flow analysis projects the amount of funds available to the licensee from all assured sources of funding and subtracts the projected decommissioning expenses. If all expenses are covered, the assurance is adequate. If the assured funds run out before all decommissioning expenses are paid, a shortfall occurs. The amount of the unfunded expenses equals the shortfall. When a shortfall occurs, the licensee does not meet the regulatory requirement to provide adequate financial assurance for decommissioning.

A simplified example showing a shortfall appears in Table 1 below.[4] The NRC specifies the minimum acceptable amount of financial assurance for decommissioning in 10 CFR 50.75(c), which includes an inflation adjustment. For the example, the minimum requirement was set at $500 million. The example shows an analysis starting 10 years before expected shutdown for a licensee that plans to begin decommissioning immediately after shutdown. At the beginning of Year 1, the licensee has accumulated $350 million in its decommissioning trust fund. To determine whether the accumulated funds provide adequate financial assurance, the staff projects the expenses and the earnings. Seven years is the default period to complete decommissioning, as stated in the regulations.[5] For the default case, the cash flow analysis assumes 1/7 of the total requirement is spent each year, so the total decommissioning expenses equal the minimum requirement. NRC regulations allow the licensee to include

4 Detailed instructions for doing the evaluation are in LIC-205, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Nuclear Power Reactors," issued March 2010. (Agencywide Documents Access and Management System (ADAMS) Accession No. ML100550465)

5 10 CFR 50.75(e)(i) and 10 CFR 50.75(e)(ii) set the 7 year default period. However, a licensee may plan to take up to 60 years to complete decommissioning by providing a site-specific cost estimate that may not be less than the required minimum of 10 CFR 50.75(c). The licensee must account for any additional costs not included in the basis for the minimum amount. The licensee can specify any expense pattern that suits its needs. If the staff agrees that the proposed expense pattern is reasonable, it will perform the cash flow analysis in a manner similar to the example.

earnings on its accumulated funds up to 2-percent real rate of return.[6] The example shows the 2-percent annual real rate of return calculated each year on the accumulated funds. For the example, only the accumulated funds and the earnings credit are shown. However, in an actual case, the amount of financial assurance may include guaranteed amounts, future ratepayer collections, and future payments under contractual obligations.[7]

Table 1. Example Cash Flow Analysis ($ Thousands)

Minimum required financial assurance = $500,000
Ending balance = Beginning Balance - Expense + 2% Earnings

Year	Beginning Fund Balance	Decommissioning Expense	2% Earnings	Ending Fund Balance
		Operation		
1	350,000	0	7,000	357,000
2	357,000	0	7,140	364,140
3	364,140	0	7,283	371,423
4	371,423	0	7,428	378,851
5	378,851	0	7,577	386,428
6	386,428	0	7,729	394,157
7	394,157	0	7,883	402,040
8	402,040	0	8,041	410,081
9	410,081	0	8,202	418,282
10	418,282	0	8,366	426,648
		Decommissioning		
11	426,648	71,429	8,533	363,752
12	363,752	71,429	7,275	299,599
13	299,599	71,429	5,992	234,162
14	234,162	71,429	4,683	167,417
15	167,417	71,429	3,348	99,337
16	99,337	71,429	1,987	29,895
17	29,895	71,429	0	**(41,534)**
	Total	500,000	109,064	

This example shows that the licensee will run out of money before completing decommissioning. No earnings are shown in the year the money runs out since the NRC's calculation method subtracts the annual expense before calculating the earnings credit. The negative fund balance in Year 17 represents the difference between the amount of financial assurance provided and the amount required by regulation. The amount of the unassured expense is the shortfall. In the example, the assurance is not adequate, and the licensee is required to produce additional financial assurance in Year 1 in the amount of $41.5 million to cover the shortfall. The coverage may be a cash deposit into the decommissioning trust or any

[6] A public utility licensee may use a real rate-of-return credit greater than 2 percent if authorized by its rate regulator

[7] The full list of available methods is specified in 10 CFR 50.75(e)(1).

other approved method, such as a parent company guarantee or other non-cash method. If a cash deposit is made in Year 1 of the example, the 2-percent earnings credit can be included. If a non-cash method is used, then no earnings may be credited since there are no funds to produce the earnings.

Response to Comments

The NRC received comments criticizing the proposed guidance that merchant plant licensees should adjust the amount of financial assurance annually to meet the minimum required amount of financial assurance specified in 10 CFR 50.75, “Reporting and Recordkeeping for Decommissioning Planning.” Some comments suggested changes to the proposed guidance. The staff responses to the comments are organized into several categories as listed below.

SAFETY

Comment 1 No Health and Safety Benefit

The proposed guidance is without any benefit to the health and safety of the public.

Response 1

The staff disagreed. The shortfalls reported in 2009 ranged from about $500,000 to $199 million per reactor.[8] The commenter did not explain why shortfalls in meeting the NRC’s minimum required amount of financial assurance presented no risk of delay to the safe and timely decommissioning of the reactors involved. Instead, the commenter asserted that an annual adjustment of financial assurance to meet the required minimum amount was unnecessarily restrictive and an undue financial burden. The comments asserted that the current economic outlook for the nuclear generation business made it unlikely that any plant would decommission in the near future. However, assertions of burden and expectations of profitable business conditions do not provide a basis for finding that no safety risk exists when the licensee does not provide adequate financial assurance for decommissioning.

On the other hand, the NRC has an extensive body of knowledge to demonstrate that a nondecommissioned reactor presents a significant radiation hazard. The NRC based its conclusion on a series of NUREG/CR reports produced by Battelle Pacific Northwest Laboratories, staff position papers presented in NUREG reports, a generic environmental impact statement noticed in the *Federal Register*, and responses to comments received from stakeholders.[9] When it issued the 1988 Decommissioning Rule, the NRC explained that inadequate or untimely financial assurance for decommissioning poses a significant risk to the health and safety benefit of the public, as expressed below:

> 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. These impacts could lead to

8 SECY-09-0146, “2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors,” p. 5, October 6, 2009.

9 53 FR 24018, 21019, General Requirements for Decommissioning Nuclear Facilities, Final Rule, July 27, 1988 (hereinafter referred to as the 1988 Decommissioning Rule).

> increased occupational and public doses, increased amounts of radioactive waste to be disposed of, and an increase in the number of contaminated sites. These regulations make clear that the licensee is responsible for the funding and completion of decommissioning in a manner which protects public health and safety....[10]
>
> The NRC has also determined that the public health and safety can best be protected if its regulations require licensees to use methods which provide reasonable assurance that, at the time of termination of operations, adequate funds are available so that decommissioning can be carried out in a safe and timely manner and that lack of funds does not result in delays that may cause potential health and safety problems.[11]

A shortfall occurs when the amount of financial assurance provided by the licensee falls short of the regulatory requirement of 10 CFR 50.75(c). A licensee with a shortfall cannot ensure that it will have enough money to safely complete decommissioning in a timely manner. That potential delay presents a risk to workers, the public, and the environment.

COMMENTS ON PROCESS

Comment 2 Notice-and-Comment Required

The proposed guidance in DG-1229 is a substantial change in the interpretation of 10 CFR 50.75. Therefore, the NRC cannot change its existing guidance to recognize annual adjustments as an acceptable method to implement the requirements of 10 CFR 50.75 without using a notice-and-comment process.

Response 2

The staff disagreed. The Commission published its interpretation of the requirements of 10 CFR 50.75 in 1996, as stated below:

> A licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[12]

The annual adjustment frequency of the proposed guidance falls within the scope of providing assurance “at any time.” To clarify the point, the final version of the guidance will include the Commission interpretation quoted above.

In addition, the NRC followed a notice-and-comment procedure for issuing the proposed guidance. The following recitation describes the notice-and-comment efforts taken to support the issuance of the guidance. The Commission issued a Notice of Issuance and Availability of Draft Regulatory Guide in the *Federal Register* on June 30, 2009.[13] The Notice solicited

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10 1988 Decommissioning Rule at 53 FR 24019.

11 1988 Decommissioning Rule at 53 FR 24033.

12 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

13 Notice of Issuance and Availability of Draft Regulatory Guide, 74 FR 31317, June 30, 2009.

comments on the draft guidance and provided instructions on submitting comments to the NRC. A comment period was established from June 30 through September 9, 2009. The NRC issued a Notice of Forthcoming Public Meeting on July 16, 2009, to inform stakeholders that a public meeting would be held in Bethesda, MD, to gather comments on the draft guidance.[14] The meeting was held as scheduled on August 20, 2009, and attracted over 100 participants via personal attendance, telephone, and Webinar. Representatives of NEI attended the public meeting. The comment period ended in September 2009, and five written comments were received. NEI provided three versions of its comments to the NRC.[15] The staff considered the comments in its final revision of the guidance.

Comment 3 Use of Guidance to Handle the Frequency of Adjustments

The NRC's long-standing position has been to handle the frequency of adjustments to decommissioning funding levels through guidance.

Response 3

The staff agreed. The NRC will continue that position by issuing guidance to handle the change to the frequency of adjustment to the amount of decommissioning financial assurance provided by a licensee.

Comment 4 NRC Rejected Annual Adjustment as Guidance in 2002

In 2002, as noted in the *Federal Register*, in response to a stakeholder comment, the NRC considered and rejected issuing guidance recommending annual funding adjustments for merchant plant licensees.

Response 4

The staff agreed that an annual funding adjustment for merchant plants was considered and rejected as guidance in 2002. However, due to changed circumstances, the annual adjustment frequency merits reconsideration.

In 2002, no licensee had reported a shortfall in its financial assurance coverage. Since then, the NRC has gained experience with two significant equity market declines that resulted in shortfalls in 2003 and 2009.[16] The historical data on the number of licensees with shortfalls, as summarized in Table 2 and discussed in Comment 5, "Case-by-Case Negotiation," indicate a potential trend to less adequate and less timely financial assurance. For example, in 2009, 26 of 27 licensees with shortfalls did not provide a plan to cover the shortfall until directed to do so

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14 Notice of Forthcoming Category 3 Public Meeting With Stakeholders to Discuss Issues Related to Biennial Decommissioning Funding Report Analysis Process (ML091970301)

15 ML092590127, ML092590128, and ML092930272

16 A third series of shortfalls occurred in 2005, but were unrelated to equity market declines. Six licensees owned by Exelon had erroneously used earnings credits in excess of the regulatory allowance when they calculated the amount of financial assurance they provided. The shortfalls were resolved by using a SAFSTOR cash flow analysis that extended the earnings period, but limited earnings to 2 percent per annum. (ADAMS Accession No. ML071070368)

by the NRC.[17] The data on licensee responses to the shortfalls in 2003 and 2009 suggest that the 2-year adjustment period is less effective than when it was first issued. As discussed in Comment 5, "Case-by-Case Negotiation," in 2003, 91 percent of licensees did not have shortfalls, and three licensees followed the existing guidance to adjust the amount of financial assurance in conjunction with the biennial decommissioning fund status report. In 2009, 75 percent of licensees had shortfalls, and 1 licensee resolved its shortfall in conjunction with its biennial decommissioning fund status report.

The circumstances outlined above conflict with the Commission's policy that "A licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning."[18]

A shortfall, by definition, indicates that the financial assurance provided by the licensee is not adequate. The 2-year adjustment frequency for merchant plant licensees placed in guidance in 2002 appeared sufficient at the time to implement the Commission policy stated above. In view of the apparent trend to less adequate and less timely financial assurance, the staff concluded that changed circumstances indicate that annual adjustment of financial assurance is appropriate.

As a final point, the staff noted that the basis of the stakeholder comment submitted in 2002 was that annual adjustments to investments held in the decommissioning trust could be expensive. However, the NRC provides other financial assurance methods that do not require adjustments to invested funds. For example, the cost of the guarantee methods ranges from minimal to a very small percentage of net income. Consequently, issuing guidance to cover shortfalls on an annual basis will not require adjustment of invested funds, which resolves the objection presented in the 2002 comment.

Comment 5 Case-by-Case Negotiation

Licensees should be permitted to resolve shortfalls after they occur using case-by-case negotiation with no time guideline for completion.

Response 5

The staff declined NEI's suggestion to resolve shortfalls after they occur using case-by-case negotiations with no time guideline for completion for the following reasons.

First, by definition, when a shortfall occurs the licensee does not provide an adequate amount of financial assurance. The Commission stated that inadequate and untimely consideration of financial assurance increases the potential risk to the public and the environment of significant adverse health and safety impacts that could occur if decommissioning is delayed due to lack of funds.[19] In view of the increased financial risk caused by a shortfall, it follows that minimizing the time period that a shortfall persists reduces the risks to public health and safety associated with a nondecommissioned reactor. Case-by-case negotiation increases the time a shortfall

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17 During the summer of 2009, the NRC issued letters to 26 licensees directing them to provide a plan of action to cover the shortfalls. One licensee submitted a plan on its own initiative to resolve its shortfall.

18 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

19 1988 Decommissioning Rule, 53 FR 24019.

persists, as compared to timely self-initiated compliance, based on the staff's experience with the shortfalls reported in 2003 and 2009. Consequently, case-by-case negotiation, particularly without a time guideline for completion, does not meet the NRC's safety objectives.

Second, the Commission rejected a case-by-case approach to decommissioning in its 1988 Decommissioning Rule, as stated below:

> Many licensing activities have had to be determined on a case-by-case basis. The procedure results in inconsistent dealing with licensees and in inefficient and unnecessary administrative effort. With the increased decommissioning expected, case-by-case procedures would make licensing difficult and increase NRC and licensee staff resources needed for these activities.[20]

The staff's experience with case-by-case negotiation to resolve shortfalls reported in 2009 confirmed the resource intensive nature of that approach. Resolving the shortfalls case-by-case cost over 1700 staff hours. The Commission's policy to avoid case-by-case decommissioning funding procedures should remain in place.[21]

Third, using the case-by-case approach may decrease the incentive of licensees to take timely self-initiated action. The NRC has experience with two significant equity market declines that played a role in causing shortfalls in licensee financial assurance. A case-by-case approach was used on both occasions. Table 2 below summarizes licensee performance in response to the 2003 and 2009 equity market declines. In 2003, about 91 percent of power reactors avoided shortfalls, while in 2009, about 75 percent avoided shortfalls. The number of licensees with shortfalls increased more than expected in relation to the percentage decline in the market. The number of licensees that corrected their shortfalls in 3 months decreased in 2009, although a greater number needed to make corrections. In 2009, 26 of 27 licensees with shortfalls did not provide a plan to cover the shortfall until directed to do so by the NRC.[22] In 2009, the number of licensees that resolved their shortfall within three months following the end of the reporting period on December 31 decreased from 3 to 1. Following the 2003 market decline, all licensees resolved their shortfalls within 1 year. In 2009, six licensees did not resolve their shortfalls within 1 year. The six licensees raised several issues: 4 licensees claimed the staff should accept NPV methods to calculate the size of the shortfall; 1 licensee provided an incomplete parent company guarantee; and 1 licensee provided a power sales contract which is under review by the staff. Comparing 2009 to 2003, the number of facilities with shortfalls increased by 18, of which 16 were merchant plants. The staff concluded that (1) the data indicated an apparent trend to less adequate and less timely financial assurance by licensees and (2) engaging in case-by-case negotiations appeared to be less effective in 2009.

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20 1988 Decommissioning Rule, 53 FR 24019.

21 The Commission made an exception for prematurely shutdown reactors on the grounds that each case presented unique funding challenges. See Decommissioning Funding for Prematurely Shut Down Power Reactors, Final Rule, 57 FR 30383, 30394, July 9, 1992. In addition, the NRC may take action to modify the licensee's schedule of accumulation of funds on a case-by-case basis (10 CFR 50.75(e)(2)).

22 During the summer of 2009, the NRC issued letters to 26 licensees directing them to provide a plan of action to cover the shortfalls.

Table 2. Market Decline and Numbers of Facilities with Shortfalls[23]

Reporting Year	Market Decline from Previous Report	Number of Facilities with Shortfalls	Number of Shortfalls Resolved in 3 Months	Number of Shortfalls Not Resolved in 1 Year
2003[24]	- 23%	9	3	0
2009[25]	- 30%	27	1	6

Allowing some licensees to delay fulfillment of their regulatory obligations prompted a licensee to raise a fairness question to the staff. The staff attended a recent Nuclear Decommissioning Trust Fund Study Group meeting. One licensee questioned the fairness of allowing large merchant fleet operators to avoid covering a shortfall for over a year while a State regulator requires a part owner of a power reactor to pay its share of decommissioning costs on schedule. Finally, the fact remains that three-quarters of NRC licensees successfully used forward-looking strategies that avoided shortfalls, despite the 2008 decline in equity values. Providing guidance to take timely action to cover a shortfall may encourage a larger number of licensees to use forward-looking strategies.

SUCCESSFUL HISTORY

Comment 6 Successful History Demonstrates No Changes Needed

No changes in the guidance are needed based on experience with the successful completion of decommissioning of public utility power reactors that had shortfalls in financial assurance at the time of permanent shutdown

Response 6

The historical success cited by the commenter relied heavily on the public utility status of the licensees involved. Utility licensees can normally obtain the consent of rate regulatory authorities to raise additional funds through ratepayer collections to cover their shortfalls. Merchant plant licensees have no access to ratepayer collections, so the economic basis of earlier successes does not apply to merchant plant licensees. In either case, licensee experience demonstrates that shortfalls should be covered in a timely manner to avoid financial stress that could cause a delay in decommissioning due to lack of funds.

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23 Decline calculated from Dow Jones Industrial Average Index closing price on December 31 of the relevant years

24 SECY-04-0019 summarized the case-by-case evaluations of six licensees that had shortfalls. The total number of shortfalls in 2003 was nine, since the SECY did not refer to three Progress Energy licensees that took self-initiated action to cover their shortfalls when the company submitted its 2003 decommissioning fund status report. The total number included 1 merchant and 8 utility facilities.

25 SECY-09-0416 describes the number and dollar amount of the shortfalls that occurred in 2009. The number of shortfalls not resolved in 1 year was determined by a review of the plans and associated response to requests for additional information submitted by licensees. The total number included 9 public utility facilities, 16 merchant plant facilities, and 2 facilities that were “hybrids,” with both utility and merchant licensee owners.

The CY experience illustrates three points that support the need for timely resolution of shortfalls. First, no licensee, including a public utility, enjoys immunity from competition that could significantly change its business outlook. Faced with lower priced competition, CY concluded that immediate retirement of its nuclear operation was the least-cost option for its customers. CY planned to supply its customers by purchasing power from lower priced competitors. Second, a shortfall in financial assurance can itself result in financial stress. When CY shut down, it had not yet collected adequate funds to decommission.[26] Although CY continued to receive funds through its wholesale power contracts, the large unfunded obligation reduced its credit rating below investment grade. Third, ratepayer funds were the source of success in resolving past shortfalls. In order to obtain cash when needed, CY required the consent of its rate regulator to raise additional funds from the ratepayers. These points are discussed further in the following paragraphs.

CY demonstrated the rapidity with which a licensee's economic outlook can decline, based on a relatively modest decrease in prices from competing sources of electricity. CY was regulated by the Federal Energy Regulatory Commission (FERC) as an electric wholesaler. In CY's case, the licensee's economic outlook shifted from viable to nonviable within 3 years, resulting in a decision to shut down immediately and prematurely.[27] The licensee stated in testimony before FERC that competitive pressure from lower priced sources of electricity was the only basis for the shutdown decision.[28]

CY based its decision on studies it performed from time to time to evaluate its costs of continued operation. A continued unit operation (CUO) study performed by CY in 1993 projected savings of $175 million from continued operation of the plant.[29] Three years later, an updated CUO study showed that the economic outlook had reversed. The 1996 CUO study showed that 13 of 14 scenarios produced savings for CY's customers by shutting down immediately and purchasing power from other sources to satisfy customer demand. The single scenario showing a positive return from continuing operation was considered unlikely since it assumed overly optimistic reductions in operating costs. The 1996 reference case projected savings of $53 million on a net present value (NPV) basis from retiring the plant and obtaining replacement power from other sources.[30] The reference case estimated the nominal dollar savings at $145 million for the remaining 10 years of operation.[31] In 1995, the last full year of operation, CY's electric sales revenues were $211 million.[32] On average, the projected nominal dollar savings of $14.5 million per year was about 7 percent of annual sales revenue. CY announced its permanent shutdown in December 1996. From this experience, the staff concluded that the time period to cover a shortfall in financial assurance should be not longer

26 As an electric utility, CY was allowed to collect funds for decommissioning over time in its rates.

27 Initial Decision, p. 9, 84 FERC ¶ 63009, August 31, 1998. (FERC Accession No. 19980901-0087)

28 Id.

29 Id.

30 Id.

31 Matrix of Sensitivity Scenarios CY Financial and Economic Analysis, December 4, 1996, CY Board Meeting. (FERC Accession No. 19980904-0309) The $53 million NPV loss and $145 million nominal loss are equivalent expressions of the projected savings from shutting down the plant. The NPV is lower due to discounting of future savings back to the date of the estimate. The nominal value is used to calculate the percentage of annual revenue represented by the projected savings since it simplifies the calculation.

32 Connecticut Yankee Atomic Power Company Statements of Income Revenue Data to Reflect Present Versus Proposed Rates, October 14, 1997. (FERC Accession No. 19980904-0495)

than 3 years, rather than allowing decades to make up the shortfall with market gains, as suggested by the commenter.

The CY experience provides an example of the financial stress that a large unfunded decommissioning obligation can cause when it comes due. After announcing the retirement of its nuclear operation, the licensee's credit rating was reduced to below investment grade.[33] The credit rating drop caused cash flow problems for the licensee. Although CY continued to receive payments from its power contracts, it needed accelerated payments to meet its current payment obligations. CY was owned by a consortium of 10 utilities in the Northeast, each of which was obligated to buy a share of the plant output under a power contract.[34] To obtain additional credit from its bank lenders, CY requested that FERC modify the amendatory agreements to its power contracts to allow accelerated payments in the event CY's cash flow was insufficient to meet its obligations as they came due.[35] CY stated that, without the modification, it would have defaulted on its mortgage bonds.[36]

Perhaps most importantly, the CY experience illustrates the advantage a public utility has in obtaining cash to cover shortfalls, as compared to a merchant plant licensee. The amounts obtained in rate case settlements in 2000 and 2006 are listed below. The amounts exceeded the NRC minimum formula specified in 10 CFR 50.75(c) for a number of reasons. The authorized collections provided for spent fuel storage costs and site restoration, which are not included in the NRC formula for the minimum required amount of financial assurance for decommissioning.[37] A number of site-specific factors, such as soil contamination and large legal expenses, also increased the costs. The NRC's regulations require a licensee to submit a preliminary decommissioning cost estimate about 5 years prior to the expected termination of operation. The preliminary cost estimate must include an up-to-date assessment of the major factors that could affect the cost of decommissioning.[38] In the CY case, the shutdown occurred 11 years before the operating license expiration date, so CY did not trigger the 5-year requirement to address site-specific factors. However, the amounts listed below illustrate the potential value of access to ratepayer funds, which is not available to a merchant plant licensee.

Additional CY funds authorized for 2000 to 2007 = \$133.6 million[39]
Additional CY funds authorized for 2005 to 2015 = \$504.3 million[40]

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33 Federal Energy Regulatory Commission Connecticut Yankee Atomic Power Company Direct Testimony of John B. Keane, p. 18, October 14, 1997. (FERC Accession No. 19980904-0296)

34 Id., pp. 7–8. The owners were themselves electric utilities who were also CY's customers, purchasing the output for resale.

35 Id., pp. 20–21.

36 Id. p. 22.

37 Spent fuel management costs are addressed in 10 CFR 50.54(bb). Site restoration costs are typically addressed by State rate regulators.

38 10 CFR 50.75(f))(3).

39 Letter Order, 92 FERC ¶ 61.055, July 26, 2000 (approving Offer of Settlement, p. 8, describing payments of \$16,742,000 annually from 2000 through 2007, April 7, 2000). (FERC Accession No. 200011203-0197)

40 Order Approving Uncontested Settlement, 117 FERC ¶ 61.192, November 16, 2006 (approving Rate Schedule FERC No. 11, August 15, 2006). (FERC Accession No. 20080826) Amount calculated as the difference between collections scheduled from 2004 through 2015 less previously approved collections from 2004 through 2007.

The potential size of an unfunded obligation in the event of premature shutdown, combined with the inability of a merchant plant licensee to obtain ratepayer funds to cover the expenses, was one of the reasons the Commission amended its financial assurance rules in 1998 as follows:

> For licensees that will not be able to collect funds through such a [ratemaking] process after industry restructuring, up-front assurance is necessary to ensure that reasonable financial assurance is provided for all decommissioning obligations. In the more competitive environment that is likely to prevail after restructuring, some of these licensees may not remain financially viable for reasons not related to decommissioning financial assurance, further suggesting the need for up-front assurance. [41]

The lessons learned from the CY experience apply to both electric utility and merchant plant licensees. Both categories of licensees face increased competition, although the merchant plant licensees are likely more sensitive to price pressure because they do not have an assured customer base or rates based on cost of service. Both categories face potential financial stress if they shut down with a large unfunded liability for decommissioning. Both categories face the need for additional funds if the decommissioning fund is not adequate at the time of shutdown. Although the CY experience resulted in a premature shutdown, the lesson remains valid for the expected shutdown on the license expiration date. The point here is the amount of the unfunded decommissioning obligation at shutdown, not whether the shutdown is premature. However, a merchant plant licensee faces a greater need to maintain adequate decommissioning financial assurance at all times during operation because it has no access to ratepayer funds. In addition, where a merchant plant is organized as a subsidiary of its parent company, the parent is generally not required to make up shortfalls in the subsidiary's financial assurance.[42]

The staff concluded that the Connecticut Yankee experience established an upper limit of 3 years for the period to cover a shortfall for licensees that do not have access to rate payer funds.

FINANCIAL BURDEN

Comment 7 Annual Adjustment of Financial Assurance is an Undue Financial Burden

The 1-year guideline to cover a shortfall is an undue financial burden.

Response 7

The staff disagreed for a variety of reasons that are discussed in the responses that follow. In brief, the Commission stated that the cost of financial assurance for decommissioning is not an inordinate financial burden for licensees in its 1988 Decommissioning Rule.[43] In fact, when the 1988 Decommissioning Rule was issued, power reactor licensees were required to make

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41 Financial Assurance Requirements for Decommissioning Nuclear Power Reactors, Final Rule, 63 FR 50465, 50469, September 22, 1998 (hereinafter referred to as the 1998 Decommissioning Rule).

42 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. *United States v. Bestfoods*, 524 U.S. 51, 61 (1998)

43 1988 Decommissioning Rule, 53 FR 24018, 24033

annual cash contributions to their external sinking funds.[44] The staff determined that the commenter overestimated the cost of providing financial assurance to support its claim of undue burden. When the actual costs are considered, the staff concluded that the cost of covering a shortfall is within the range anticipated by the NRC when the financial assurance regulations were issued and amended. In addition, as discussed in Comment 2, "Notice-and-Comment," the frequency of annual adjustment is within the scope of the Commission's policy that a licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[45]

Comment 8 Letter of Credit (LOC) Fees are an Undue Financial Burden

Fees for a letter of credit impose an undue financial burden on licensees. For example, the cost of a letter of credit is approximately 4% of the assured value on an annual basis.

Response 8

In forming its response, the staff reviewed the 1998 Decommissioning Rule notification to merchant plant licensees that giving up public utility status could significantly increase the amount of financial assurance they would be required to produce. The rule stated the following:

> … the amount that would need to be assured under such a [letter of credit or surety bond] mechanism (i.e., the difference between the licensee's decommissioning cost estimate and the current balance in its external sinking fund) could in some cases be quite large.[46]

The Commission went on to explain that if a merchant plant licensee could not obtain an LOC or surety, then another mechanism would be necessary, such as a PCG, which was less costly,[47] or providing full upfront funding in a prepayment mechanism.[48] The fact that the amounts of the shortfalls in 2008 were quite large falls within the scope of the notification provided in 1998. Licensees must provide the minimum financial assurance amount even if the shortfall is quite large.

The Commission also addressed shortfalls caused by events outside the licensee's control. Under the provisions of 10 CFR 50.75(e)(1)(v), a licensee may use a power sales contract as financial assurance. The contract must require that payments will be made regardless of "force majeure" conditions that would otherwise permit the contracting parties to terminate or renegotiate the contract.[49] The NRC listed several examples of "force majeure" conditions that

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44 See 10 CFR 50.75(e)(3)(iii) (1988), 1988 Decommissioning Rule, 53 FR 24050. At the time, all power reactors were electric utilities.

45 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

46 1998 Decommissioning Rule at 63 FR 50465, 50471.

47 The Commission stated that the self-guarantee method eliminates the cost of third party financial assurance, such as the LOC and surety (Self-Guarantee as an Additional Financial Assurance Mechanism, Final Rule, 58 FR 68726, December 29, 1993). The self-guarantee is similar to the parent guarantee, so the same cost conclusion applies.

48 1998 Decommissioning Rule at 63 FR 50465, 50471.

49 1998 Decommissioning Rule at 63 FR 50465, 50472.

would not excuse the requirement to provide adequate financial assurance: recession, inflation, and severe market changes.[50]

To summarize the *Federal Register* statements quoted above, the NRC notified merchant plant licensees that the burden of covering a shortfall could be quite large and that a severe market change would not excuse the requirement to provide adequate financial assurance. The commenter argues that the burden of covering the shortfalls is largely due to a severe market decline. That argument falls within the scope of shortfalls that must be covered, as described in the *Federal Register.* Consequently, the burden of covering a large shortfall caused by a market decline, similar to the situation in 2009, has been evaluated and determined to be necessary to ensure adequate assurance that funds for decommissioning will be available when needed.

The staff is not aware of a power reactor licensee that currently uses an LOC for nuclear decommissioning financial assurance. However, to gain insight on the use of the method, the staff reviewed the use of LOCs by parent company owners of power reactors. The staff found that some large power reactor fleet owners use large amounts of LOCs for many purposes unrelated to nuclear decommissioning. For example, Florida Power and Light (FPL) uses LOCs to guarantee obligations in the amount of $737 million.[51] FirstEnergy Corp. uses LOCs in the amount of $2.1 billion.[52] The staff concluded that the LOC is a viable method to guarantee a future obligation.

In addition, the staff compared the commenter's estimated cost of an LOC of 4 percent per year with other sources of information. The staff found many sources indicating that the commenter had overestimated the cost. Historically, the staff found that the fee for an LOC has been around 1.5 percent per annum. For example, in a final rule issued in 1993, the NRC reported that, for licensees other than power reactors, annual fees for LOCs, surety bonds, and other forms of third party financial assurance typically are approximately 1.5 percent of the amount of financial assurance provided.[53] FirstEnergy Corp. reported that annual fees for its LOCs ranged from 0.35 percent to 1.70 percent as of 2008.[54] A materials licensee, with revenues and decommissioning obligations comparable to a power reactor owner, recently reported that the cost for an LOC was about 1 percent of the face value. However, that licensee found that a surety would be even less costly and opted to use the surety method of providing financial assurance with an annual fee of 0.75 percent. Considering all sources surveyed, the staff found that the range of fees for an LOC was 0.35 percent to 2.5 percent.[55] The high end of the range

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50 Id., Footnote 1.

51 FPL Group, Inc., Florida Power and Light, Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, Form 10-Q, p. 38, September 30, 2009 (hereinafter referred to as FPL 2009 Form 10-K).

52 FirstEnergy Corporation, 2008 Annual Report, p. 96.

53 Self-Guarantee as an Additional Financial Assurance Mechanism, Final Rule, 58 FR 68726, December 29, 1993.

54 FirstEnergy Corporation, 2008 Annual Report, p. 96.

55 A nonpower reactor applicant reported in March 2010 that it would obtain an LOC for a 2-percent fee (Personal communication, C. Montgomery, Project Manager, NRC). EnergySolutions reported the cost for an LOC at 2.5 percent (EnergySolutions, Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, p. 72, February 27, 2009). McDermott, Inc., which owns a fuel fabrication facility, reported fees of 1.125 percent to 1.875 percent for its LOCs (McDermott International, Inc., Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, p. 52). US Bank

was reported by companies with much smaller revenues and assets than power reactor fleet owners. The staff concluded that a range from 0.35 to 1.7 percent is a reasonable estimate for power reactor licensees. The staff used that range to estimate the cost of covering the 2009 shortfalls using an LOC. The 2009 shortfalls totaled $2.4 billion.[56] Twenty-seven facilities operated by six parent companies fell short of the regulatory requirement.[57] Of the 27 facilities, 26 did not resolve their shortfalls within 3 months. The combined annual revenue of the six parent companies was $93 billion, and their combined net income was $6.2 billion.[58] For the industry, the staff estimated that the tax-adjusted cost of using an LOC to cover the shortfall would have been between $5.5 million and $27 million. The range of cost per reactor, using an LOC, was calculated from the reactors with the lowest and highest shortfalls. The cost estimates for the three guarantee methods are presented in Table 3 for the 26 facilities that did not resolve their shortfalls within 3 months. The actual cost would likely have been lower, since many licensees resolved their shortfalls using other methods in less than a year and could have dropped the LOC or surety.

Table 3. Estimated Cost for 26 Licensees To Cover Shortfalls Reported in 2009

Item	Guaranty Mechanism			
	Letter of credit		Surety	PCG[59]
Cost, % of Face Value	0.35	1.7	0.75	0
Industry cost	$8.4 million	$41 million	$18 million	$0
Tax-adjusted industry cost[60]	$5.5 million	$27 million	$12 million	$0
Tax-adjusted industry cost as % of annual revenue	0.006	0.029	0.013	0
Tax-adjusted industry cost as % of net income	0.09	0.44	0.19	0
Range of shortfalls per reactor	$500,000–$199 million	Same	Same	Same
Tax-adjusted cost per reactor	$1,100 to $455,000	$5,500 to $2.2 million	$2,400 to $975,000	$0

Comment 9 Fees for a LOC May Increase in Negative Markets

Fees for a letter of credit may increase in a strongly negative market, such as the one experienced in 2008. A letter of credit may not be available during strongly negative market conditions

stated that it charged an LOC fee of 1 percent for firms with investment grade credit rating, with a carrying charge of 0.4 percent per year for a standby LOC (Personal communication, P. Fredrichs, US Bank).

56 SECY-09-0146, “2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors,” p. 7, October 6, 2009. (ADAMS Accession No. ML092580041)

57 Id., p. 6.

58 Sums calculated from annual reports to shareholders and SEC Form 10-K.

59 Licensees that have no parent company cannot use the PCG. However, they could use a self-guarantee, which has a more stringent financial test, but no financing costs.

60 35-percent corporate tax rate (Publication 542, Corporations, p. 17, U.S. Internal Revenue Service).

Response 9

The staff's survey of costs for LOCs included the 2008 time period, as discussed in the response to Comment 8, "Letter of Credit (LOC) Fees are an Undue Financial Burden." The costs were a very small percentage of the resources of the parent companies that own power reactors. The available information did not indicate whether those costs had increased from earlier periods.

However, licensees have the ability to make forward-looking plans to address the inescapable volatility of the equity markets. A commercial firm typically arranges for credit facilities to assure access to funds and credit when needed. Using its credit facilities, a firm has the ability to make a forward looking plan to ensure the future availability of and reasonable pricing for LOCs. For example, FPL Group, Inc., which owns a number of power reactor licensees, reported that its credit facility provided access up to $6.4 billion worth of LOCs.[61] In addition, the NRC provides flexibility in the methods allowed for providing financial assurance. Licensees that face potentially higher than average LOC costs have the ability to use other methods.

In view of the above, the staff did not agree that the potential increased cost and difficulty of obtaining an LOC after a market decline justifies a delay in covering a shortfall.

Comment 10 The Parent Company Guarantee (PCG) Imposes Significant Costs

A parent company guarantee imposes significant indirect costs due to its prohibition on using the pledged assets as collateral for any other obligation, which can lead to credit stress, possibly even a ratings downgrade. For example, providing a PCG for $300 million could result in significant adverse financial consequences due to the requirement to set aside assets worth at least six times the amount guaranteed, and a prohibition on pledging the set-aside assets as collateral for other any other obligation.

Response 10

The staff concluded that the commenter overestimated the indirect cost of the PCG due to misunderstanding the provisions of Appendix A to 10 CFR Part 30, which governs the PCG. However, the staff reviewed an extensive body of information to verify that the PCG did not impose indirect costs on the parent company.

The PCG is simply an agreement between a parent company and its licensee subsidiary.[62] Under the terms of the PCG, the parent agrees to pay funds into the decommissioning trust, up to the face amount of the PCG, if the licensee fails to meet its decommissioning obligation. It has no financing costs, and the commenter did not assert any.[63] Licensees that have no parent

61 FPL Group, Inc. 2009 Annual Report, p.93

62 Revision 1 to RG 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," p. 57, October 2003.

63 The NRC stated that the self-guarantee, which is similar to the PCG, was provided as a financial assurance mechanism, in part, on the basis that it would eliminate the financing cost of third party methods, such as an LOC, insurance, or a surety. See 58 FR 68726. The self-guarantee requires a higher credit rating ("A") and greater assets (10 times the amount guaranteed) than a PCG. See Appendix C, "Criteria Related to Use of Financial Tests and Self Guarantees for Providing Reasonable Assurance of Funds for Decommissioning," to 10 CFR Part 30.

company cannot use the PCG.[64] However, those licensees may use the self-guarantee, which is very similar, but has a more stringent financial test.[65] The evaluation of costs described below applies equally to the PCG and the self-guarantee.

The staff disagreed that the PCG imposed indirect costs via “setting aside” assets that would otherwise be available to serve as collateral for other obligations. The commenter cited NRC regulations as the basis of its statement. However, the commenter misunderstood Appendix A to 10 CFR Part 30, which governs the PCG. The regulation imposes a financial test which requires the parent company to “have” an investment grade bond rating, tangible net worth at least six times the amount guaranteed, and assets located in the United States with a value at least six times the amount guaranteed.[66] The regulation does not require the parent company to set aside any assets and it places no restriction on using the parent’s assets as collateral for any other purpose. The NRC provides regulatory guidance on PCGs in RG 1.159 and NUREG-1577, “Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance,” Volume 3. The guidance contains model language for the PCG agreement that must be submitted to the NRC to implement the regulations of Appendix A to 10 CFR Part 30. The PCG agreement recites the financial test criteria of the regulation and states the amount the parent will provide in the event the licensee fails to perform its required decommissioning activities. The PCG agreement does not impose a requirement to set any funds aside in anticipation of a default by the licensee, and it does not restrict the parent company’s use of its funds in any way. The staff concluded that neither the regulation nor the regulatory guidance contained any restrictions on the use of the parent company’s assets that would impose the indirect costs asserted by the commenter.

The regulatory history of the PCG supports the staff’s conclusion that the PCG method does not impose indirect costs. The NRC added the PCG method at the request of licensees for materials and research and test reactors when it issued the original financial assurance rules in 1988.[67] The NRC issued the PCG rule on the basis that it would minimize impacts on licensees.[68] Later, in 1998, the NRC extended the use of the PCG to power reactors in response to a comment requesting that action.[69] None of the comments received in response to either of the NRC rulemakings made a claim that indirect costs would make the PCG unworkable. Similarly, the U.S. Environmental Protection Agency (EPA) has allowed PCGs as financial assurance for environmental cleanup obligations.[70] The EPA did not receive comments in its rulemaking activities that claimed the PCG imposed indirect costs.[71]

The staff reviewed relevant accounting standards to determine whether accounting practices might impose indirect costs not previously considered by the NRC. The staff found no previously unconsidered indirect costs. Accounting for decommissioning costs is specified

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64 Appendix A to 10 CFR Part 30.

65 Appendix C to 10 CFR Part 30.

66 An alternate financial test the licensee may choose does not require an investment grade bond rating, but adds two requirements: (1) to meet certain financial ratios and (2) to have net working capital worth at least six times the amount guaranteed. No licensee currently uses this alternate test to qualify for the PCG.

67 1988 Decommissioning Rule, 53 FR 24018, 24034.

68 1988 Decommissioning Rule, 53 FR 24018, 24035.

69 63 FR 50465, 50470–71, September 22, 1998.

70 40 CFR 264.143(f).

71 Personal communication, P. Bailey, ICF Consulting. Mr. Bailey has extensive experience with the NRC and EPA financial assurance regulations. He has provided consulting services to the NRC on many occasions.

under Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143).[72] The standard arose from a request from the Edison Electric Institute to the Financial Accounting Standards Board (FASB) to address accounting for the costs of nuclear decommissioning, as well as similar costs incurred in other industries.[73] FASB issued SFAS 143 in 2001, to be effective for fiscal years beginning after June 15, 2002.[74] The standards in SFAS 143 require a company to record its decommissioning liability on its balance sheet using specific procedures based on the amount of the decommissioning cost, the time when the costs will be incurred, and the company's borrowing rate. The relevant point is that the PCG does not affect the size of the decommissioning liability, its timing, or the parent's borrowing rate, so using a PCG does not affect the asset retirement accounting procedures.

FASB established a specific standard to define the disclosure requirements for corporate guarantees in FASB Interpretation No. 45 (FIN No. 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," issued in November 2002. FIN No. 45 states that guarantees issued between a parent company and its subsidiary are not required to be recognized as a liability on the balance sheet.[75] The PCG fits into the exception established by FIN No. 45, therefore, it is not required to be recorded on the balance sheet as a liability. For example, in its 2004 Annual Report, Progress Energy disclosed that it used PCGs for nuclear decommissioning in a section titled, "Off-Balance Sheet Arrangements and Contractual Obligations."[76] The PCG is off the balance sheet because it is not recorded as a liability. In view of this, the staff concluded that the relevant accounting standards do not impose indirect costs of the type asserted by the commenter.

The staff reviewed financial reports from three licensee parent companies to verify its conclusion. In the following examples, the parent companies used LOCs and parent guarantees with very large dollar amounts for many purposes. PCGs used for nuclear decommissioning were a small percentage of the total.

The first example involves Duane Arnold, which used a $93 million PCG provided by its parent, FPL Group, as part of its decommissioning financial assurance. FPL Group disclosed the PCG in its September 2009 Quarter Report, in a note titled, "Guarantees and Letters of Credit," which stated the following:

> FPL Group and FPL obtain letters of credit and issue guarantees to facilitate commercial transactions with third parties and financings. Letters of credit and guarantees support, among other things, the buying and selling of wholesale energy commodities, debt and related reserves, capital expenditures for wind development, nuclear activities, the commercial paper program of FPL's consolidated VIE from which it leases nuclear fuel and other contractual agreements. Each of FPL Group and FPL believe it is unlikely that it would incur any liabilities associated with the letters of credit and guarantees. Accordingly, at

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72 R. Schroeder, S. Sevin, K. Yarbrough, "Reporting Effects of SFAS 143 on Nuclear Decommissioning Costs," *Int'l Advances in Econ. Res.*, Vol. 11, p. 450, 2005.

73 SFAS 143, p. 24, June 2001.

74 Id. p. 6.

75 FIN No. 45, p. 4.

76 Progress Energy 2004 Annual Report, p. 43.

> September 30, 2009, FPL Group and FPL did not have any liabilities recorded for these letters of credit and guarantees.[77]

As of September 2009, FPL Group had LOCs totaling $737 million and guarantees with a notional amount of $9.6 billion.[78] The $93 million PCG provided for Duane Arnold was a small amount compared to the total amount of guarantees issued by FPL Group. Note that, despite the large total amount of the guarantees, FPL Group did not record them on its balance sheet. Disclosing such guarantees without recognizing them as liabilities on the balance sheet is consistent with FIN No. 45, as discussed above. FPL Group reported that it received credit ratings of "A" or better by the three major credit rating agencies.[79] The disclosures and credit ratings reported by FPL Group contradict the commenter's assertion that use of a PCG is likely to result in credit stress and possible credit rating downgrading.

FirstEnergy Corp., owner of Beaver Valley, provided a second example of a parent company with large amounts of LOCs and parent guarantees. In 2008, FirstEnergy Corp. used $2.1 billion in LOCs[80] and, including its subsidiaries, provided $3.8 billion in guarantees.[81] At the time, FirstEnergy Corp. used an $80 million PCG for Beaver Valley.[82] The Beaver Valley PCG is small compared to the total amount of guarantees. In addition, FirstEnergy Corp. made the following statement:

> We believe the likelihood is remote that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with ongoing energy and energy-related activities.[83]

When reading the FirstEnergy Corp. statement quoted above, the word "remote" is a term of art in accounting use. A loss contingency classified as "remote" is defined as one with only a slight chance of occurring.[84] Accordingly, it does not require recognition on the balance sheet as an accrued liability.[85]

FirstEnergy Corp.'s credit ratings also contradict the commenter's assertion that using PCGs leads to potential credit downgrading. In fact, Standard and Poor's changed its outlook for FirstEnergy Corp. from "negative" to "stable" and upgraded the credit rating of several of FirstEnergy Corp.'s subsidiaries from BBB- to BBB.[86] The upgrading occurred during a period when FirstEnergy Corp. carried $5.9 billion in LOCs and parent guarantees.

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77 FPL Group, Inc. Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, 2009 Form 10-Q, p. 38, September 30, 2009. [Hereinafter FPL 2009 Form 10-Q]

78 Id.

79 FPL 2009 Form 10-Q, p. 38

80 FirstEnergy Corp., 2008 Annual Report, p. 96.

81 FirstEnergy Corp., 2008 Annual Report, p. 37.

82 Id.

83 Id.

84 Preliminary Summary of Financial Accounting Standards for Environmental Liabilities, Intangible Assets and Climate Change Risk, Draft Report, U.S. Environmental Protection Agency, p. 12, April 28, 2008. Available at http://www.epa.gov.

85 Id., p. 13.

86 FirstEnergy Corp., 2008 Annual Report, p. 35.

The staff reviewed a third example where three power reactor licensees used the PCG as a timely, minimal cost method for providing temporary financial assurance in response to an equity market decline. Progress Energy, which owns electric utility licensees, demonstrated the PCG's usefulness in its March 28, 2003, biennial decommissioning fund status report. A licensee must determine the status of its decommissioning fund as of December 31 of each even numbered year and file a report by the following March 31, although in certain circumstances the licensee must submit the report annually. Progress Energy informed the NRC that the decommissioning trust fund balances for three of its public utility reactors (Robinson 2, Brunswick 1 and 2) did not cover the minimum required amount specified in 10 CFR 50.75(c), as stated below:

> However, in order to provide an amount at least equal to the estimated decommissioning costs for each of those facilities, the trust funds are being combined with parent company guarantees, pursuant to 10 CFR 50.75(e)(1)(iii)(B), as identified on Attachments 1, 2, and 3. The financial tests required by 10 CFR 30, Appendix A, and other documents recommended by draft Regulatory Guide 1106 to support the guarantee are enclosed.
>
> The use of the parent company guarantees is considered an interim measure for maintaining compliance with the regulations. The reactors identified in Attachments 1, 2, and 3 are currently at different stages in the license renewal process. When issued, license renewal is expected to improve the status of the respective trust fund. If the status of a trust fund improves such that financial assurance of decommissioning funds can be established without the use of the associated parent company guarantee, PEC plans to terminate the associated parent company guarantee, as permitted by the regulations.[87]

The shortfalls resulted from a decline in the equity markets.[88] The amount guaranteed for the three reactors was $276 million,[89] which is very close to the $300 million NEI asserted would cause financial stress and credit rating downgrading. In fact, Progress Energy's credit ratings were downgraded, although for reasons unrelated to the PCGs issued to cover the shortfalls. Progress Energy stated that its credit ratings had been downgraded due to the slower-than-planned pace of its efforts to pay down debt from its acquisition of Florida Progress.[90] However, in contradiction to the commenter's assertion of the consequences of credit downgrading, the company stated that it remained in the investment grade category, and that the downgrades had not materially affected its access to liquidity or the cost of its short-term borrowings. In accordance with FIN No. 45, the PCGs were not recorded as liabilities on the balance sheet.[91]

The staff drew several conclusions from the Progress Energy experience. First, the use of a PCG as a temporary measure to cover a shortfall is a proven technique. Second, a licensee has the ability to provide PCGs to cover shortfalls within 3 months. Third, even in a case in

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87 Letter, Biennial Decommissioning Funding Status Report and Notification of Change in Decommissioning Funding Method, p. 2, March 28, 2003. (ADAMS Accession No. ML030970280)

88 Progress Energy 2003 Annual Report, p. 35.

89 Progress Energy 2003 Annual Report, p. 87. Progress Energy had $1,057 million of parental guarantees outstanding at the time, including the $276 million for nuclear decommissioning. Progress Energy was authorized by its rate regulator to issue up to $3 billion in guarantees (Id., p. 36).

90 Progress Energy 2003 Annual Report, p. 38.

91 Progress Energy 2004 Annual Report, p. 43.

which a credit downgrading occurs, a licensee does not necessarily experience liquidity difficulties or higher short-term borrowing costs. Fourth, a licensee anticipating license renewal can cover a shortfall with a PCG until the renewal application is resolved. Finally, it appears there are no financial reasons to avoid using a PCG to cover a shortfall, if the parent can pass the NRC's financial test.

New reactor applications also contradict the commenter's assertion that PCGs in the range of $300 million impose significant indirect costs on a licensee. The combined license application for the Bell Bend Nuclear Power Plant stated that it would provide a PCG in the amount of $398.6 million. The applicant did not identify any potential financial stress caused by indirect costs from its planned use of the PCG.[92]

As another check, the NRC staff discussed the effect of a PCG on a company's financial statements with the staff of the Securities and Exchange Commission (SEC). The SEC has authority under Section 19 of the Securities Act of 1933 to establish generally accepted accounting procedures for public companies.[93] SEC staff stated that using a PCG would not be expected to result in credit downgrading or reduced liquidity.[94]

The staff also contacted Moody's Investor Services, one of the three major credit rating agencies in the United States. The Moody's analyst had personal knowledge of the methods used to develop the ratings for large parent companies that own nuclear reactors. The analyst stated that parent company guarantees (PCGs) are considered when developing a rating for a company. But, when a guarantee is contingent with little likelihood of performance, it normally has little weight in the rating. The staff noted that the PCG allowed by the NRC is a contingent agreement because the PCG does not require performance on the part of the parent company unless the licensee subsidiary is not able to provide funds when needed for decommissioning. However, NRC regulations require a licensee subsidiary to accumulate full funding of decommissioning costs by the time of permanent shutdown, so the expectation is that the PCG provided for decommissioning financial assurance would not normally require performance. The analyst stated that a PCG of that nature would not normally be expected to affect the liquidity analysis or credit rating of the parent company, in view of the assets and cash flow of companies that operate power reactors for electricity production.[95]

In view of the above information, the staff concluded that the direct and indirect costs to a licensee using a PCG are minimal and are not an undue financial burden.

Comment 11 NRC Should Allow More than 3 Months to Cover a Shortfall

Covering a shortfall in the 3-month timeframe between the end of the decommissioning fund status reporting period on December 31 and the fund status report due date on the following March 31 could result in higher costs and diversion of resources from operating plants.

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92 Bell Bend Nuclear Power Plant Combined License Application, Part 1: General and Administrative Information, Revision 1, p. 1-11, February 27, 2009. (ADAMS Accession No. ML090710465)

93 William W. Bratton, *Private Standards, Public Governance: A New Look At The Financial Accounting Standards Board*, p. 7, *Boston College L. Rev*. Vol. 48:1, January 2007.

94 Personal communication, A. Simmons, NRC attendee at the SEC meeting.

95 Personal communication, T. Fredrichs, US NRC.

Response 11

A licensee has the ability to make forward-looking plans to meet the decommissioning financial assurance requirements before the December 31 recalculation of the minimum requirement for decommissioning. As noted in Comment 10, "The Parent Company Guarantee (PCG) Imposes Significant Costs," Progress Energy's experience demonstrated that 3 months provide sufficient time to cover a shortfall without adverse impacts to a company's liquidity or short-term borrowing costs. If a PCG is used, no costs are incurred. Using an LOC or a surety, the costs are a very small percentage of the resources available to the licensee. Where the licensee uses a forward looking plan to arrange a credit facility to issue LOCs, an LOC can be obtained within 3 months. Using either method, no diversion of resources from an operating plant would be necessary. In view of this information, the staff concluded that the cost of covering a shortfall within 3 months did not justify a delay in covering a shortfall.

Comment 12 Impact on Immediate Priorities

Additional funds placed in the decommissioning trust to cover a shortfall could possibly impact more immediate priorities, which places an undue burden on the licensee.

Response 12

The staff disagreed with this comment for two reasons.

First, the regulations do not specify the timing of adding funds to the decommissioning trust. As discussed above, a licensee may select from a variety of methods to provide financial assurance at reasonable cost. That flexibility allows the licensee to control the timing of making contributions to its decommissioning fund as necessary. No undue burden exists with respect to the timing of cash contributions to the decommissioning trust.

Second, the staff disagreed on the grounds that the NRC found that requiring annual contributions to the decommissioning trust was not an undue burden when it issued the 1988 Decommissioning Rule. In particular, at that time, the NRC compared the cost of requiring annual cash deposits with the cost of keeping an internal reserve as a financial assurance method.

The NRC recognized that the cost of placing funds in a prepaid account or an external sinking fund was more expensive than allowing the licensee to hold the funds in an internal reserve.[96] However, the NRC rejected the use of an internal reserve, despite its lower apparent expense. In doing so, the NRC listed several reasons for concluding that the cost of paying into a prepaid account or an external sinking fund was not an inordinate financial burden on the licensee.[97] First, an external sinking fund could be collected over time.[98] That remains true for utility licensees. Merchant plant licensees can also use an external sinking fund, if combined with a PCG, to effectively gain the same advantage allowed to utility licensees. Second, the favorable tax treatment of decommissioning trust funds reduces the cost differential between the external

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96 50 FR 5600, 5608, Decommissioning Criteria for Nuclear Facilities, Proposed Rule, February 11, 1985.

97 1988 Decommissioning Rule, 53 FR 24018, 24033.

98 Id.

sinking fund and an internal reserve.[99] Third, many licensees engage in diversified financial activities which involve more financial risk, and it is increasingly important that decommissioning funds be provided on a more assured basis.[100] Fourth, in the event of bankruptcy, there is not reasonable assurance that internal reserves can be effectively protected from the claims of creditors.[101]

The staff concluded that the reasons listed in 1988 remain valid today for concluding that cash payments into a prepaid fund or external sinking fund are not an undue financial burden.

Comment 13 Annual Adjustments Invite Poor Investment Behavior

Requiring adjustments over a short period of time could invite poor fund investment behavior, such as seeking higher risk, short-term investments to increase near-term earnings and regain liquidity tied up in PCGs.

Response 13

The staff disagreed that requiring a licensee to cover a shortfall could result in poor investment behavior, regardless of the time period allowed for adjustments.

The NRC regulations impose a number of safeguards prohibiting poor investment behavior on the part of merchant plant licensees.[102] First, the trust agreement must specify that the fund manager will follow, at a minimum, a prudent investor standard of care. The trust may not be amended in any material respect, such as the standard of care requirement, without written notification to, and absence of objection from, the NRC. The licensee is prohibited from engaging in the day-to-day management direction of the fund, except for passive investments tracking market indices. The safeguards placed on fund management prevent poor fund investment behavior such as seeking higher risk, short-term investments.

The staff disagreed that regaining liquidity tied up in PCGs could serve as a rational incentive to engage in poor investment behavior. The discussion of the PCG above demonstrates that the PCG does not tie up funds and does not decrease liquidity.

Finally, the fact remains that three-quarters of NRC licensees used financial assurance strategies that avoided shortfalls in 2009. The performance of the large majority of licensees demonstrates that a licensee has the ability to make forward-looking plans to ensure adequate financial assurance at any time during the life of the facility. Establishing and using a forward-looking plan will remove the incentive to engage in risky fund investment behavior for short-term gains. Providing guidance to cover a shortfall on an annual frequency should encourage licensees to adopt forward-looking plans that avoid shortfalls, rather than relying on market growth to make up the shortfall.

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99 Id.

100 Id. The potential risk of diversified financial activities may be more relevant today then in 1988.

101 Id.

102 10 CFR 50.75(h)(1) imposes the conditions on merchant plant trust funds. The NRC did not impose similar conditions on public utility licensee trust funds on the grounds that NRC oversight was not necessary because rate regulators exercised authority over the funds. See Decommissioning Trust Provisions, Final Rule, 67 FR 78332, 78333, December 24, 2002.

Comment 14 Licensees Should Have as Much Flexibility as Pension Fund Managers

Licensees require flexibility to manage long-term investments during periods of market crisis, analogous to the Congressional reduction of funding targets for pensions in the Worker, Retiree, and Employer Recovery Act of 2008, which reduced the mandatory minimum contributions required of employer-provided pension fund plans.

Response 14

The staff disagreed that the Worker, Retiree, and Employer Recovery Act (WRERA) of 2008 offers a relevant analogy to NRC licensees.

The basis of Congressional action in the WRERA of 2008 was to avoid job losses that could have occurred if cash-strapped employers were required to make large mandatory contributions to their pension funds. During the discussions with NRC licensees in the summer of 2009, no licensee claimed that it would experience job losses as a result of covering the shortfalls in financial assurance. To the extent that the WRERA was motivated by the desire to save jobs, it has no relevance to NRC licensees.

Likewise, the method used by the WRERA of 2008 has no relevance to NRC licensees. The method selected by Congress to implement the goal of the WRERA was to reduce the size of mandatory contributions to the pension funds.[103] In contrast, the NRC does not require mandatory contributions into decommissioning funds.[104] Under NRC regulations, a licensee has the flexibility to choose cash contributions or noncash guarantee methods to provide financial assurance for decommissioning. That flexibility allows the licensee to manage its cash flows as necessary in a market crisis without seeking relaxation of the decommissioning funding requirements. Therefore, the mechanism used by the WRERA is irrelevant to NRC licensees.

However, additional factors contradict the commenter's argument that employers managing pension funds enjoy greater flexibility than NRC licensees possess in managing decommissioning financial assurance. Pension funding is subject to an extensive regulatory system that provides assurances and penalties that are not part of the NRC's system. The commenter engaged in cherry-picking by singling out a favorable provision while ignoring the disfavored provisions. Two examples of pension funding protections that offset the risk of a temporary reduction in pension fund contributions will further demonstrate the inaptness of the analogy offered by the commenter.[105] The most significant protection for pension funding is the Pension Benefit Guaranty Corporation (PBGC), which provides insurance to cover shortfalls in pension funds.[106] Employers must pay the insurance premiums.[107] A second significant

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103 Technical Explanation of H.R. 7327, "Worker, Retiree, And Employer Recovery Act Of 2008," As Passed By The House On December 10, 2008, Joint Committee on Taxation, pp. 28–29, December 11, 2008 (hereinafter referred to as Technical Explanation of H.R. 7327). Available at http://www.dol.gov/ebsa/pdf/HR7327JCTTechnicalExplanation.pdf.

104 However, 10 CFR 50.75(e)(2) authorizes the NRC to modify a licensee's schedule for accumulation of funds.

105 In the WRERA of 2008, Congress temporarily reduced the funding targets for pension funds according to the following schedule: 94 percent for 2008, 96 percent for 2009, and 98 percent for 2010. See Technical Explanation of H.R. 7327, The "Worker, Retiree, And Employer Recovery Act Of 2008," As Passed By The House On December 10, 2008, Joint Committee on Taxation, Dec. 11, 2008, p.29, *available at* http://www.dol.gov/ebsa/pdf/HR7327JCTTechnicalExplanation.pdf

106 61 FR 39278

protection requires the imposition of liens against the employer's property for failing to make timely contributions to the pension plan. When the shortfall in a pension fund exceeds $1 million, the pension statutes provide that a lien in favor of the plan shall be placed on the employer's property in the amount of the unpaid balance.[108]

As a final point, the flexibility permitted by the NRC's regulations already provide greater flexibility than allowed under pension funding rules. NRC licensee may choose from a variety of financial assurance methods in addition to making cash deposits into a trust fund. The NRC provides three methods of non-cash guarantee methods, and allows credits for future collections and earnings. This flexibility allows NRC licensees to manage their cash flows in a manner that best serves their needs while still providing adequate financial assurance for decommissioning. In contrast, the pension funds have only one option—to set funds aside in trust.[109]

In view of the above discussion, the NRC's regulations already permit its licensees adequate flexibility to adjust contributions to decommissioning trust funds as needed, as long as the required minimum is maintained using some combination of approved methods.

Comment 15 Cash Contributions Cause Overfunding

Making a cash contribution to the decommissioning trust after a market decline will result in overfunding when the market recovers.

Response 15

The commenter confused funding with financial assurance.

"Funding" refers to the actual amount of funds available for decommissioning. A fully-funded decommissioning trust would have a balance that meets or exceeds the minimum required amount of 10 CFR 50.75(c). Until a fund is fully-funded, it cannot be overfunded. The distinction will be clearer by understanding the several components that make up the amount of financial assurance provided by a licensee.

"Financial assurance" refers to the system of regulation used by the NRC to assure that funds are available when needed for decommissioning. It also refers to the total amount of assurance provided using one or more of the methods specified in 10 CFR 50.75(e). When referring to the total amount of financial assurance, it is the sum of funds accumulated in a segregated account outside the licensee's control plus the amount of any guarantees provided; plus the projected amounts of earnings on the accumulated funds; plus projected ratepayer collections by utilities; plus projected nonbypassable charges authorized by a rate regulatory agency; plus, for Government licensees, the amount provided by a statement of intent; plus projected payments from certain contractual obligations that meet NRC requirements; plus projected earnings on collections, payments, and nonbypassable charges. If applicable, financial assurance may include other methods, if the NRC determines that they provide a level of assurance equivalent to the methods of 10 CFR 50.75(e). However, in contrast to the amount of funding, a licensee is

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107 General FAQs about PBGC. Available at http://www.pbgc.gov/about/wrfaqs.html.

108 Employee Retirement Income Security Act of 1974, as amended, Section 303(k).

109 Eric D. Chason, "Outlawing Pension-Funding Shortfalls," p. 520, *Va. Tax Rev.*, Vol. 26, 2007.

required to provide financial assurance at all times during the life of the facility, through termination of the license, that adequate funds will be available to complete decommissioning.[110]

Until the trust accumulates enough funds to pay for decommissioning, it is underfunded in the sense that the available funds are less than the amount needed to pay for decommissioning. However, when the earnings credit is added to an underfunded trust, the sum may exceed the amount needed for decommissioning. Thus, when the market recovers, the trust may become "overassured" while remaining "underfunded." If the licensee elects to use cash contributions to cover the shortfall, a market recovery could yield an overassured result, but would provide the advantage of increasing the likelihood that full funding will be achieved at the time of termination of operations. In addition, cash contributions reduce the vulnerability of the fund to market volatility, which strengthens the licensee's ability to avoid future shortfalls. Alternatively, if the licensee wanted to preserve cash for other purposes, it could use a guarantee method to provide assurance in an amount no larger than necessary to cover the shortfall. If the market increases, the licensee can then discontinue the guarantee. In either case, the staff concluded that the potential for overassurance did not justify a delay in covering a shortfall.

Comment 16 Annual Adjustments Would Impose Unnecessary Premiums

If the proposed guidance were applied to the 2009 decommissioning status report, the NRC would effectively be forcing utilities to pay an unnecessary premium for decommissioning funds that will not be used for decades. To illustrate this point, the funds for those merchant nuclear plants that were identified as having shortfalls as of December 31, 2008, have collectively increased in value by well over $300 million through July 2009 with no action on the part of licensees.

Response 16

The commenter argues from hindsight. Looking backward to calculate the amount the market recovered, as the commenter did, misses the mark. When the licensees submitted their decommissioning fund status reports on March 31, 2009, no one could predict, looking forward, when or if the market would recover its value. The commenter attempts to justify delay in covering a shortfall by looking backward and observing that the actual market recovery produced gains without taking any action. However, trying to justify delay in covering a shortfall by claiming the market will "really" increase greater than the 2-percent real rate of return was discussed and rejected in Response 18.

At the same time, the commenter misses the obvious question of what might have happened if the licensees had followed the existing guidance. RG 1.159 currently provides guidance to make needed adjustments in conjunction with the decommissioning fund status report that is required by March 31 of odd numbered years. As noted earlier, 26 of 27 licensees did not resolve their shortfalls as of March 31, 2009. The staff estimated the gain that could have been realized if the merchant plant licensees referenced by the commenter had increased the investments held in their trust funds on March 31, 2009, when they submitted their decommissioning fund status reports. The Dow Jones Industrial Average increased about 20

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110 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

percent from the end of March to the end of July 2009.[111] If the merchant licensees had covered their shortfalls by investing cash in their trust funds on March 31, 2009, they could have earned 20 percent on an additional \$1.7 billion, or about \$340 million.[112] The gain would have been in addition to the \$300 million in recovery reported by the commenter for the no action strategy used by the licensees. The staff concluded that the merchant plant licensees could have earned more than double their actual gain if they had followed the existing guidance.

Of course, the staff calculation suffers from the same hindsight error that the commenter employed. The point is that no one can predict the direction or timing of the market looking forward. Therefore, licensees should make forward-looking plans that take market volatility into account. As discussed earlier, the NRC regulations allow the use of guaranty methods with minimal cost to provide financial assurance in cases in which the licensee wants to preserve cash. Therefore, the staff concluded that the potential for market recovery does not justify delay in covering a shortfall.

INVESTMENT HORIZON

Comment 17 License Renewal Adds 20 Years to Accumulate Funds

The current business outlook makes it likely that most power reactors will have an additional 20 year time horizon to accumulate funds by obtaining license renewal.

Response 17

The staff disagreed that the availability of license renewal provides an extra 20 years to accumulate funds. License renewal merely provides the option of continued operation; it provides no guarantee that operation will actually continue. In support of that position, the staff noted that since the License Renewal Rule was issued in 1991,[113] eight power reactors have permanently shut down without applying for license renewal.[114] The commenter conceded the potential that a reactor may not seek license renewal in his statement the “most” reactors will “likely” obtain license renewal. Until a license has actually been renewed by the NRC, the potential added time horizon remains speculative, which does not justify a delay in covering a shortfall in decommissioning financial assurance.

Comment 18 Investments Will Grow to Fulfill Decommissioning Obligations

Decommissioning funds are long-term investments that will grow over time to fulfill a future obligation. For example, SAFSTOR provides up to 60 years to accumulate funds. It is unnecessary to cover a shortfall on a short-term basis since, over the long term, decommissioning funding will be adequate.

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111 The Dow Jones Industrial Average closing price for March 31, 2009, was 7608.39; the close on July 31, 2009, was 9171.61.

112 The \$1.7 billion was the gross shortfall for the merchant plants in 2009.

113 Nuclear Power Plant License Renewal, Final Rule, 56 FR 64943, December 13, 1991.

114 NUREG-1350, Volume 21, 2009–2010 Information Digest, Appendix B, August 2009.

Response 18

The staff compared the commenter's confident prediction of well-timed market growth with a similarly confident prediction from Shakespeare's King Henry IV:

> Glendower: I can call spirits from the vasty deep.
>
> Hotspur: Why, so can I, or so can any man;
> But will they come when you do call for them?[115]

Substitute, "I can call capital gains from the misty future," for Glendower's boast and Hotspur's skeptical retort applies equally well to the claim that the stock market will produce cash on demand to pay for decommissioning.

The claim that a long-term investment will cover decommissioning expenses relies on the assumption that the market will rise. Of course, many studies support the general notion of a long-term average rise in stock market value.[116] However, saying the market will rise is like saying Denver is uphill from San Francisco—true on the average, but it ignores significant peaks, valleys, and flats along the way. And, unlike the trip to Denver, the path of the market is unpredictable. The commenter ignored both volatility and unpredictability in his assumption.

Equally important, the commenter is forced to implicitly assume that the market will grow at a rate higher than the 2-percent real rate of return allowed by the NRC regulations. That assumption is required to support the commenter's argument because, when a shortfall occurs, the earnings credit projected using the NRC's 2-percent rate does not provide adequate funding to pay for decommissioning, when combined with all other methods of assurance provided by the licensee. That is, a cash flow analysis would show that the licensee would run out of money. Table 1, "Example Cash Flow Analysis," illustrates that situation. If the licensee does not provide any additional financial assurance to cover the shortfall, the argument that the investment will grow to fulfill the obligation amounts to a claim that the earnings credit will "really" be greater than a 2-percent real rate of return.[117] That implicit assumption exceeds the regulatory limit. The NRC considered and rejected using a higher real rate of return in its analysis for the 1998 Decommissioning Rule.[118]

However, many organizations have considered how much to rely on uncertain market returns as a source of funding for large future obligations. The staff reviewed this information to gain insight on how much weight should be given to potential market gains when determining how frequently adjustments should be made to cover shortfalls in decommissioning financial assurance.

As a first step, the staff examined actual market performance since the end of the 19th century. Table 4 displays data on long-term bear markets. The data reveal significant periods of time

115 William Shakespeare, King Henry VI, Part I, Act 3, Scene 1. *Available at* http://www.shakespeare-literature.com/Henry_IV,_part_1/8.html

116 Peter A. Diamond, "What Stock Market Returns to Expect for the Future?," *Social Security Bulletin*, Vol. 63, No. 2, p. 38, 2000.

117 Public utility licensees may use a higher rate, if authorized by their rate regulator. The same arguments apply, but turn on the utility licensee's higher rate of return.

118 1998 Decommissioning Rule, 63 FR 50477

when the market did not rise at a rate greater than the NRC's 2-percent real rate of return allowance. When looking at the table, the annual returns cannot be directly compared to the NRC's 2-percent annual real rate of return. To make the comparison, the NRC's rate must be converted to a nominal rate that includes inflation. For example, during the period shown in the last row of Table 4, from 2/1/00 to 12/1/09, the inflation rate was approximately 2.7 percent per year. [119] When the inflation rate is added to the NRC's real rate, the result is approximately 4.7 per year. That is, applying the NRC's real rate of return to the period from 2/1/00 to 12/1/09 implies that the actual annual return would have been 4.7 percent. Using the inflation-adjusted annual rate, the market should have achieved a cumulative increase of about 58 percent, rather than the -4.68 percent it actually achieved. Inspection of Table 4 shows that actual performance fell short of the projection for the decade. The frequency and duration of the long-term bear markets appear significant enough to question the ability of capital gains to provide cash when needed. The staff concluded that a licensee that relied too heavily on projected earnings as a source of funds may encounter difficulty in accumulating adequate funds for decommissioning.

Table 4. Long-Term Bear Markets 1896 to 2009[120]
Dow Jones Industrial Average Index

Start Date	End Date	Duration in Years	Annual Return	Cumulative Return
2/1/06	6/1/24	18	-0.24%	-4.29%
9/1/29	11/1/54	25	0.07%	1.69%
2/1/66	10/1/82	17	0.05%	0.83%
2/1/00	12/1/09	10	-0.48%	-4.68%

The staff considered information gathered by the Social Security Advisory Board (SSAB). In 2001, the SSAB solicited the views of distinguished economists to consider whether to change the Social Security system to include some form of investment of funds in private equities.[121] A key element in the evaluation was whether historical rates of return for the last century should be used to make long-term projections over the coming decades or whether an alternative rate or range of rates is more appropriate.[122] Among the views presented to the SSAB were the following statements by Professor John Y. Campbell, who is the Morton L. and Carole S. Olshan Professor of Economics at Harvard University:

> The unprecedented nature of recent stock market behavior makes it impossible to base forecasts on historical patterns alone.…[123]

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119 Inflation calculated from the Consumer Price Index – Urban, as compiled by the Bureau of Labor Statistics.

120 Rydex Security Global Investors, using data on the Dow Jones Industrial Average Index. For purposes of the chart, a secular bear market, or downward-trending market, occurs when a trend does not rise above the previous high. Available at http://www.getalts.com/downloads/dowJonesChart.shtml. Last visited May 27, 2010.

121 Forecasting U.S. Equity Returns in the 21st Century, Estimating the Real Rate of Return on Stocks Over the Long Term, Presented to the Social Security Advisory Board, p. 1, August 2001.

122 Id.

123 John Y. Campbell, "Forecasting U.S. Equity Returns in the 21st Century," Estimating the Real Rate of Return on Stocks Over the Long Term, Presented to the Social Security Advisory Board, p. 7, August 2001. Available at http://www.ssab.gov/Publications/Financing. Last visited April 6, 2010.

> [I]t is impossible to predict timing of market corrections …[124]
>
> Finally, I note that it is tricky to use these numbers appropriately in policy evaluation. … Even if the probability of underperformance is small over a long holding period, it cannot be zero or the stock market would be offering an arbitrage opportunity or "free lunch."[125]

Professor Eric D. Chason, Associate Professor of Law at the University of Virginia School of Law, provided a pithier statement of the uncertainty of market growth. The following statement appears in his article on pension funding shortfalls:

> Volatility is a property of markets; it is not a disease for which accounting is the cure.[126]

Professor Chason's view particularly applies to the use of SAFSTOR to extend the time period for adding earnings credits to the amount of financial assurance. SAFSTOR does not cure market volatility.

A second set of pragmatic experts on decommissioning funding—namely, NRC licensees—support Professor Campbell's views that market growth cannot simply be assumed to cover future obligations. For example, Dominion Resources, Inc. (Dominion), owns seven operating reactors and one reactor in decommissioning. The following statement in Dominion's 2009 annual report to the SEC leaves no doubt that decommissioning trust funds may suffer poor market growth, which could require significant additional funding for decommissioning:

> Market performance and other changes may decrease the value of decommissioning trust funds and benefit plan assets or increase Dominion's liabilities, which could then require significant additional funding.…These assets are subject to market fluctuation and will yield uncertain returns, which may fall below expected return rates.…If the decommissioning trust funds and benefit plan assets are not successfully managed, Dominion's results of operations and financial condition could be negatively affected.[127]

The Zion Nuclear Power Station (Zion) license transfer provides a case study illustrating that a well-informed industry participant will not rely on market growth as the basis for funding an actual decommissioning project.

In the Zion case, Exelon Generation Company, LLC (Exelon) agreed to transfer the license and decommissioning liability for the Zion site to ZionSolutions, LLC (ZionSolutions). ZionSolutions was formed for the sole purpose of decommissioning the Zion site and maintaining the Zion independent spent fuel storage facility; it is a wholly owned subsidiary of EnergySolutions,

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124 Id., p. 12.

125 Id., p. 8.

126 Eric D. Chason, "Outlawing Pension-Funding Shortfalls," *Va. Tax Rev*., Vol. 26, 2007, quoting Lawrence N. Bader & Jeremy Gold, "Reinventing Pension Actuarial Science," The Pension Forum, January 2003, at 1, 12.

127 Dominion Resources, Inc., Annual Report Pursuant to Section 13 of 15(d) of the Securities Exchange Act of 1934, Form 10-K, p. 24, February 26, 2010. Available at http://investors.dom.com.

Inc.[128] In exchange, ZionSolutions obtained the decommissioning trust funds. As originally agreed, the closing date for the transfer was scheduled for the end of 2008.[129] The project was expected to take 10 years.

However, after the transfer application was submitted, the Zion decommissioning trust fund balance declined about 10 percent by October 2008.[130] The drop in market value prompted EnergySolutions to defer the license transfer and delay the decommissioning start date as stated in the following announcement:

> EnergySolutions does not believe that it is in the best interests of its stakeholders to finalize the transfer of the Zion Nuclear Power Station assets until after the financial market stabilizes and the company reaffirms that there is sufficient value in the Zion decommissioning trust funds to ensure adequate funds for the accelerated decommissioning of the plant…[131]

EnergySolutions' decision to defer the Zion license transfer demonstrates that a well-informed market participant will not depend on market growth to cover a shortfall in funds needed to complete decommissioning.

The staff drew the following conclusions from the above information: (1) allowing shortfalls to persist implicitly accepts an earnings projection in excess of the amount provided in the NRC's regulations, (2) the probability of market underperformance over a long holding period is not zero, (3) using the 60-year SAFSTOR period to project earnings does not cure market volatility, (4) the consequences of market underperformance could require the licensee to provide significant additional funding, (5) a licensee that relied too heavily on market returns as a source of funds may encounter difficulty in accumulating adequate funds for decommissioning, and (6) market volatility can delay decommissioning. On that basis, the staff concluded that relying on unpredictable long-term market growth to cover a shortfall does not provide adequate financial assurance that funds will be available when needed.

However, additional reasons argue against reliance on long-term market growth to cover shortfalls.

Waiting for the markets to "sort themselves out"[132] gives a competitive advantage to licensees who choose to rely heavily on market gains to provide funds for decommissioning. They can increase net income a bit above similarly situated competitors that take a less optimistic view of the market as a funding method. The competitive advantage may provide an incentive for

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[128] Application for License Transfers and Conforming Administrative License Amendments (hereinafter referred to as the Zion Transfer Application), cover letter, p. 2, January 25, 2008. (ADAMS Accession No. ML080310521)

[129] Zion Transfer Application, Enclosure 6, Schedule & Financial Information for Decommissioning, p. 1, January 25, 2008.

[130] Steve Daniels, "Credit Crisis Delays Start of Cleanup at Exelon's Zion Nuke," Crain's Chicago Business, October 14, 2008. Available at http://www.chicagobusiness.com/cgi-bin/news.pl?id=31397.

[131] Id.

[132] Exelon Generation Company, LLC stated that, "the most prudent course of action is to allow time for the financial markets to sort themselves out from such a fall in value…." Transcript, U.S. Nuclear Regulatory Commission Briefing On Decommissioning Funding, pp. 9–10, February 23, 2010. (ADAMS Accession No. ML010610257)

licensees to adopt a reactive strategy of addressing shortfalls after they occur, with no particular urgency, rather than following a forward-looking strategy of avoiding shortfalls.

Fairness issues arise when some smaller licensees do not have the same flexibility as the large fleet owners. An owner of a minority interest in a power reactor raised a fairness issue to a staff member attending the Nuclear Decommissioning Trust Fund Study Group in May 2010. The owner remarked that it must pay over the decommissioning charges required by its rate regulator annually. That owner expressed the view that it was unfair that small State-regulated utilities must pay when owners of large fleets of reactors are allowed to delay.[133]

The issue of fairness to future generations also comes into play when considering the market gain argument as a financial assurance method. In a 1977 report to Congress on the NRC's approach to decommissioning, the Comptroller General of the United States stated the following:

> We believe the cost of decommissioning should be paid by the current beneficiaries, not by future generations.[134]

Using future market gains to pay for decommissioning transfers the cost from the current beneficiaries of energy production to a future generation. The issue of intergenerational equity argues against heavy reliance on capital gains to fund decommissioning.

Finally, as a technical point, reliance on market gains would be difficult to use as a regulatory mechanism. Hope springs eternal that the market will rise quickly in the near future. Waiting for the markets to "sort themselves out" does not appear to have an obvious endpoint to select as a regulatory deadline.

Comment 19 SAFTOR Extends the Investment Horizon

As a collateral benefit, the long investment horizon provided by SAFSTOR increases the amount of financial assurance credited to a trust fund balance.

Response 19

The NRC's regulations provide 60 years or more, if approved, to decommission a reactor.[135] The decommissioning period may include a period of safe storage, known as SAFSTOR.[136] However, safety and waste disposal issues formed the NRC's basis for providing SAFSTOR as a decommissioning option:

- The primary purpose of the SAFSTOR period is to enhance worker safety by allowing time for decay of radioactivity in the workplace.[137]

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133 Personal communication, A. Simmons, NRC, reporting a comment made at the recent Nuclear Decommissioning Trust Fund Study Group meeting.

134 Cleaning Up the Remains of Nuclear Facilities—A Multibillion Dollar Problem, Report No. EMD-77-46, p. 25, June 16, 1977.

135 10 CFR 50.82(a)(3).

136 1988 Decommissioning Rule, 53 FR 24018, 24022.

137 Decommissioning Criteria for Nuclear Facilities, Proposed Rule, 50 FR 5600, 5603, February 11, 1985.

- Other factors that could delay decommissioning include the following:[138]
    - the unavailability of waste disposal capacity
    - the presence of operating nuclear facilities on the same site

In view of the purpose of SAFSTOR, the collateral effect of extending the period of projected earnings should not be understood to allow delay in covering a shortfall. The NRC's rules still require the licensee to accumulate the full amount of funds needed for decommissioning by the time of permanent shutdown. The Commission stated this requirement on at least four occasions as follows:

> Combination of these steps, first establishing a general level of adequate financial responsibility for decommissioning early in life, followed by periodic adjustment, and then evaluation of specific provisions close to the time of decommissioning, will provide reasonable assurance that the Commission's objective is met, namely that at the time of permanent end of operations sufficient funds are available to decommission the facility in a manner which protects public health and safety.[139] (1988)
>
> Moreover, the provisions of §§ 50.82(a) and 50.75(e) reflect the Commission's objective that *"at the time of permanent end of operations* sufficient funds are available to decommission the facility in a manner which protects public health and safety".[140] (1991) [emphasis in original]
>
> The NRC disagrees with recommendations that the NRC should abandon its general policy of requiring all funds needed for decommissioning be available prior to the start of final dismantlement. As described in the proposed rule (56 FR 41493), the June 27, 1988, final rule clearly requires funds at the time of permanent end of operations.[141] (1992)
>
> First, it should be noted that § 50.75(e)(1) and (2) also require full funding of decommissioning ''at the time termination of operation is expected.'' Thus, the commenters have not provided a complete picture of the situation.[142] (2002)

The NRC's rules allow a licensee to use earnings projected into the SAFSTOR period as part of its financial assurance. However, if a shortfall continues to exist after the SAFSTOR earnings credit is included, the licensee has exhausted the benefit and must cover the remaining shortfall. An example of a shortfall that exceeds the benefit of the additional earnings credit is discussed in Comment 20, "NRC Should Use NPV Methods for Financial Assurance Calculations."

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138 10 CFR 50.82(a)(3); 1988 Decommissioning Rule, 53 FR 24018, 24023.

139 1988 Decommissioning Rule, 53 FR 24018, 24030–31.

140 Decommissioning Funding for Prematurely Shutdown Power Reactors, Proposed Rule, 56 FR 41493, August 21, 1991.

141 Decommissioning Funding for Prematurely Shutdown Power Reactors, Final Rule, 57 FR 30384, 30395, July 9, 1992.

142 67 FR 78332, Decommissioning Trust Provisions, Final Rule, December 24, 2002.

NET PRESENT VALUE (NPV)

Comment 20 NRC Should Use NPV Methods for Financial Assurance Calculations

Using calculation methods that are not based on net present value improperly mix current and future values for the same obligation.

Response 20

The staff considers its use of current and future values appropriate for the purpose of evaluating compliance with the rule to provide financial assurance in an amount that may not be less than the specification of 10 CFR 50.75(c)(1) and 10 CFR 50.75(c)(2).

The staff is aware of the applications of NPV and discount rates for making decisions in capital investment analysis[143]. However, use of NPV can result in levels of financial assurance that are not adequate to pay for decommissioning.[144] An example of the NPV method that led to underestimating a shortfall in financial assurance is discussed below. But first, the NRC's method of incorporating inflation and future cash flows in its analysis will be discussed.

The first step in the NRC's evaluation makes an inflation adjustment to obtain the cost of decommissioning in current year dollars. The minimum estimated cost of decommissioning is specified in 1986 dollars in 10 CFR 50.75(c)(1). The escalation rate used to adjust the 1986 cost to current dollars is specified in 10 CFR 50.75(c)(2). The licensee must report the amount of funds accumulated for decommissioning in current year dollars in accordance with 10 CFR 50.75(f)(3). The escalation performed by the staff permits a direct comparison of the requirement to the licensee's reported funds.

If the licensee does not have sufficient funds in its decommissioning trust to cover the cost of decommissioning, the staff will include amounts assured by other methods, such as guarantees, projected earnings, and future payments. The staff uses 2009 dollars in this part of its analysis. That is, the amounts are not adjusted for inflation after 2009. The staff uses 2009 dollars to estimate the amounts expected to be received in the future for two reasons. First, it allows direct use of the 2-percent real rate of return specified in the regulations. The real rate of return is already adjusted to subtract inflation, as explained by the Federal Reserve Bank:

> Real interest:
> Interest rates adjusted for the expected erosion of purchasing power resulting from inflation. Technically defined as nominal interest rates minus the expected rate of inflation.[145]

Second, using constant 2009 dollars simplifies the evaluation. If nominal, inflation-adjusted future payments and earnings were included, the staff would need to make projections of the inflation rate. Then, it would convert the nominal future values back to 2009 dollars to complete the analysis. Using 2009 dollars throughout the analysis reduces the administrative burden on

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143 1998 Decommissioning Rule, 63 FR 50465, 50477.

144 Id.

145 Glossary, The Federal Reserve Bank of Minneapolis. Available at http://www.minneapolisfed.org/glossary.cfm#r.

the staff. As noted in the 1988 Decommissioning Rule, one of the objectives of codifying financial assurance requirements was to reduce the administrative burden of providing financial assurance.[146] The constant dollar approach aligns with that objective.

As a result of using constant 2009 dollars for the analysis, a cash flow occurring in the future does not require discounting to be compared with a cash flow occurring in the present. Using the NPV method to discount the results of the NRC's evaluation could result in an inadequate amount of financial assurance, since it would amount to a double subtraction of inflation.

Table 5 below illustrates the differences between using the 2-percent earnings method and the NPV method to evaluate financial assurance. It compares the results of the staff analysis and the licensee analysis of financial assurance submitted for a power reactor with a shortfall as of December 31, 2009. The staff used the constant dollar method described above. The licensee used an NPV method. Both analyses express the cash flows in constant 2009 dollars and begin the analysis with the licensee's decommissioning trust fund balance as of December 31, 2009. The only point of agreement between the two methods is the fund balance as of October 17, 2026, when the plant operating license will expire.[147]

Enclosure 4 shows the decommissioning expense amounts and timing as determined by the licensee in a site-specific cost estimate. The first three years show high expense when the plant will be prepared for a 49 year safe storage period. Then, in 2079, the licensee plans to complete the decommissioning over a 10 year period. The staff found the expenses reasonable and used them for its cash flow analysis.

The staff analysis follows the method explained in the previous section titled, "NRC's Evaluation Method for Decommissioning Financial Assurance." The results are shown in Enclosure 3. The staff analysis shows the trust fund balances at the beginning and end of each year, with subtractions for the annual expense and additions for annual earnings at a 2-percent real rate of return. The staff analysis shows that the money will run out in 2083. There will be approximately $68 million in expenses remaining after the assured funds run out. The entries in Table 5 for the staff results can be read directly off the staff's spreadsheet.

The licensee's analysis is shown in Enclosure 4. It does not display the decommissioning trust fund balances or the earnings credit. The total expense can be read directly from the spreadsheet. However, the column labeled "Decommissioning Cost Less Decommissioning Period Credit" requires explanation. The licensee explained that the column represented the NPV of the decommissioning cost for the year, discounted back to 2026. As a result, the licensee's spreadsheet does not show that the money will run out in 2083. The licensee nevertheless determined that a shortfall existed, as shown in the boxed table on page 2 of Enclosure 4. The relevant figures are reproduced in Table 5.

Referring now to Table 5, an explanation is needed for the differences in the staff and licensee results. Turning first to the "Decommissioning Period Credit," the staff's figure is much less than the licensee's figure. The staff figure was calculated as the total of all the annual earnings on the trust fund balance from 2026 until the funds ran out, as shown on the staff spreadsheet.

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146 1988 Decommissioning Rule, 53 FR 24030.

147 The slight difference in projections appears to be due to details of how spreadsheets handle the number of days in a leap year.

The licensee calculated the figure by subtracting the total of its annual "Decommissioning Cost Less Decommissioning Credit" values from the total decommissioning cost. Or, more concisely, the licensee subtracted the NPV of the expenses from the expenses. The staff was unable to discover a logical reason why the licensee's calculation would yield a result that equaled the 2-percent earnings calculation performed by the staff. In any event, comparing the licensee figure to the staff figure shows that the licensee figure for the credit exceeds the amount of cash that the trust fund balance is projected to earn using the 2-percent rate, after subtracting the decommissioning expense. The staff concluded that the licensee's calculation of the amount of earnings credited to the decommissioning trust was incorrect.

Table 5 shows that the staff and the licensee estimated different shortfall amounts. Note, however, that the shortfall amounts depend on the date. The staff used 2009 dollars since that is the date at which the shortfall must be covered. The licensee selected two dates to calculate the NPV of the shortfall – 2026 and 2009. Referring to the boxed table on page 2 of Enclosure 4, the licensee calculated the shortfall as $14 million and $10 million. The $14 million figure represents the difference between the licensee's estimated actual and required amount of financial assurance as of the date of license expiration. The $10 million figure represents the licensee's estimate of how much additional cash would be needed in the decommissioning trust as of 2009 to increase the projected earnings enough to cover the projected expenses. The staff concluded the licensee's calculations were incorrect.

The last row of Table 5 shows the projected trust fund amount calculated by the staff and the licensee. The staff's figure of $286 million can be read off its spreadsheet. The highest value occurs on the first day, since the expenses draw down the balance faster than the earnings can replenish it. The licensee's calculation appears on the page 2 of Enclosure 4. The licensee calculated the total projected trust fund amount by adding the balance on October 17, 2026 to its figure for "Decommissioning Period Credit" to arrive at $600 million. The staff concluded that the licensee's calculation was incorrect.

The example shows that the NPV method can produce an incorrect and undervalued result for a shortfall in decommissioning financial assurance.

Table 5. Comparison of Staff and Licensee Calculations of Shortfall ($ 2009)

Calculated Amount	Staff Calculation Using 2% Return	Licensee Calculation Using NPV Method
10/17/2026 Balance	286,249,000	286,233,000
Plus Decommissioning Period Credit	259,519,864	313,775,000
Less Total Cost	614,184,000	614,184,000
Surplus (Shortfall) as of 2026	Not calculated	(14,179,000)
Surplus (Shortfall) as of 2009	(68,415,136)	(10,166,000)
Total Projected Trust Fund Amount	286,249,000	600,008,000

An additional weakness of the NPV concept bears mentioning. NPV varies depending on the future time at which the shortfall occurs, so equal shortfalls may yield different NPVs, which make comparison of licensee performance more complex. Table 6 below illustrates this weakness. The time periods were selected to show the difference for a renewed license term, a full-term license, and a renewed license term plus a 53-year safe storage period following permanent shutdown.

Table 6. Variability in NPV of Shortfall

Shortfall	NPV @ 2% for Shortfall Occurring in the Future		
	20 Years in Future	40 Years in Future	73 Years in Future
$100,000,000	$67,297,133	$45,289,042	$23,560,661

The above discussion explains why the NRC does not use NPV to determine the amount of a shortfall.

Comment 21 NRC Does Not Comply with Generally Accepted Accounting Procedures

Using calculation methods that are not based on net present value is at odds with generally accepted accounting practices (GAAP).

Response 21

The staff disagreed that GAAP restrict the NRC's authority to choose the method best suited to make its independent evaluation of the adequacy of financial assurance provided by a licensee. The Commission addressed that point in its 1998 Decommissioning Rule as follows:

> The commenter's concern that 2 percent is less than the 7 percent and 3 percent discount rates called for in NRC's regulatory analysis guidance is not relevant. Discount rates are used for capital investment analysis and other decision-making purposes but, if used to calculate contributions to decommissioning funds, could result in financial assurance levels that are not adequate to pay for all assured obligations.[148]

The staff referred to the FASB for additional insight on the applicability of GAAP to the NRC's evaluation of licensee financial assurance. Since 1973, FASB has been designated by the SEC as the private-sector standard setter for GAAP for the United States.[149] Based on statements issued by the FSAB, the NRC sees no contradiction in using methods other than GAAP to make its decisions. In the following statement, FASB recognizes that GAAP are limited in the role they play:

[148] 63 FR 50465, 50477.

[149] William W. Bratton, "Private Standards, Public Governance: A New Look At The Financial Accounting Standards Board," p. 7, *Boston College L. Rev*., Vol. 48:1, January 2007.

> The role of financial reporting in the economy is to provide information that is useful in making business and economic decisions, not to determine what those decisions should be.[150]

Furthermore, FASB recognizes that end users of financial reports have a responsibility to do their own independent evaluation of information reported under GAAP, as stated below:

> Investors, creditors, and others may use reported earnings and information about the elements of financial statements in various ways to assess the prospects for cash flows. They may wish, for example, to evaluate management's performance, estimate "earning power," predict future earnings, assess risk, or to confirm, change, or reject earlier predictions or assessments. Although financial reporting should provide basic information to aid them, they do their own evaluating, estimating, predicting, assessing, confirming, changing, or rejecting.[151]

The independent evaluation performed by the NRC is consistent with that responsibility.

Comment 22 Licensees Should Be Permitted to Use NPV Methods

Licensees should be permitted to use net present value methods to determine the amount of a guarantee provided for financial assurance.

Response 22

The staff disagreed for three reasons.

First, as demonstrated in the response to Comment 20, "NRC Should Use NPV Methods for Financial Assurance Calculations," the NPV method can result in financial assurance levels that are not adequate to meet all future obligations.

Second, the regulations provide for an earnings credit only for funds held in a prepaid account or an external sinking fund. The regulations governing the guarantee methods do not provide for an earnings credit.

Third, there are no funds associated with a PCG or other guarantee method, so there is nothing that can generate earnings.

Some licensees have suggested that the PCG could be converted into cash, which could be placed in an account that produces earnings. Therefore, an earnings credit should be added to the face amount of the PCG for financial assurance purposes. To see why the potential convertibility does not solve the problem, think of a PCG as a box of money buried in the ground that will be dug up to pay for a shortfall in financial assurance. No matter how long you wait, it is just a box of money with exactly the same amount as when it was buried. For example, suppose that the licensee will have a shortfall of $30 million dollars 20 years in the future. The

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150 Statement of Financial Accounting Concepts No. 1, Objectives of Financial Reporting by Business Enterprises, as amended, FASB, p. 10, November 1978. Available at http://www.fasb.org.

151 Id., p. 2.

NPV of that shortfall, using a 2-percent discount rate, is $20 million. The licensee puts $20 million in a box and buries it on site. Twenty years later, when the licensee digs up the box, it still has $20 million. The box full of money is not enough to pay the $30 million shortfall.

Comment 23 NRC Approved NPV Methods in the Past

The NRC approved three license transfers which included parent company guarantees calculated by the applicant using the net present value method.

Response 23

With respect to the license transfer cases referenced by the commenter, the staff noted that each case was completed before the staff issued its procedure for analyzing reactor decommissioning funding assurance. The procedure is Office Instruction LIC-205, "Procedures for NRC's Independent Analysis of Decommissioning Funding Assurance for Operating Nuclear Power Reactors." LIC-205 was issued in 2006, while the latest of the references provided by the commenter was completed in 2005. Consequently, the three cases have no value as precedent. LIC-205 established the method used by the NRC to measure the adequacy of the licensee's financial assurance and determine the amount of a shortfall, if any. Due to the lack of regulatory provisions to apply NPV calculations to the guarantee methods, as well as the inherent inaccuracy of the method when used to determine the adequacy of financial assurance, LIC-205 does not provide for the NPV method.

UTILITY LICENSEES

Comment 24 Do Not Address Funding in Every Rate Case

The guidance should not state that public utility licensees should address decommissioning funding at every rate case.

Response 24

The staff agreed that addressing decommissioning funding in "every" rate case before the licensee's rate regulator could lead to duplication of effort. A licensee may have more than one active docket before its rate regulatory authority. The final version of RG 1.159, Revision 2, will not advise the licensee to address decommissioning funding at every rate case.

Comment 25 Good Faith Efforts for Rate Relief

Guidance endorsing good-faith efforts by public utility licensees to obtain rate relief should not be removed from the existing guidance. A reasonable amount of time should be allowed to pursue rate relief.

Response 25

The statement on good-faith efforts was removed from the proposed guidance in favor of stating that the licensee should address decommissioning funding in every rate case. As noted above, the final version of RG 1.159, Revision 2, will not recommend that the licensee address decommissioning funding in every rate case.

When the commenter proposed reinstating guidance that the licensee should use good-faith efforts to obtain rate relief, no suggestion was made on what action would constitute a good-faith effort. The commenter offered no suggestion on the timeframe to complete the action.

Two objectives informed the staff's evaluation of what action would constitute a good-faith effort by the licensee and the time period for taking the action.

First, the NRC has a policy to minimize its involvement with the rate-making process.[152] Obtaining rate relief for a shortfall would logically start with the rate regulator receiving information that the shortfall had occurred. The rate regulators perform periodic reviews of decommissioning costs and funding. However, State rate regulators perform reviews of decommissioning fund balances on a frequency that generally ranges from semiannual to once every 5 years.[153] One option for a licensee would be to wait until the next scheduled rate review to inform its rate regulator of the shortfall. However, that strategy may not be appropriate, depending on the size of the shortfall, the time when the next review is scheduled, and the time when the decommissioning funds will be needed. Another consideration is that waiting for the next scheduled review does not constitute taking action.

The staff concluded that the licensee should take self-initiated action to notify its rate regulator when a shortfall occurs and request a review of decommissioning funding. The rate regulator can then use its processes to determine the appropriate timing and level of adjustment in ratepayer collections. In addition, action by the licensee will minimize the involvement of the NRC in the process, as compared to the NRC communicating directly with the rate regulator to provide information on a licensee's shortfall.

Second, in considering the timing of the licensee's action, the staff was informed by the NRC's policy that requires the licensee to provide adequate financial assurance at all times. This policy states the following:

> A licensee is required to provide assurance that at any time during the life of the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning.[154]

As discussed in Introduction, the optimal timing to cover a shortfall is annually. That conclusion was based on the CY experience of economic distress within 3 years, the apparent decline in effectiveness of the existing 2-year guidance, and the requirement that the licensee must provided adequate financial assurance at any time during the life of the facility. The timing for a utility licensee to notify its rate regulator should be March 31, when a shortfall occurs on the previous December 31. The March and December dates coincide with the reporting requirements of 10 CFR 50.75(f) and are consistent with the guidance for merchant plant licensees. In the notification, the licensee should describe the amount of the shortfall and the potential effect it could have on decommissioning funding. The licensee should request that its rate regulator review its decommissioning funding within the year.

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152 1988 Decommissioning Rule, 53 FR 24030.

153 SECY-07-0197 (ML072610606)

154 Decommissioning of Nuclear Power Reactors, Final Rule, 61 FR 39278, July 29, 1996.

The staff determined that the 6 year period to obtain rate relief in the existing guidance should be reduced to 5 years to coincide with upper end of the typical rate regulator review schedule.

Putting the burden of notification on the licensee conforms to the NRC's policy of minimizing its involvement with the rate regulatory process. However, the NRC retains the authority to take additional actions, either independently or in cooperation with FERC or the licensee's State public utilities commission, as appropriate, including modification of the schedule to accumulate funds.

EDITORIAL COMMENT

Comment 26 References in Guidance

References cited in the guidance should be updated.

Response 26

The staff agreed.

Staff Calculation Using 2% Earnings

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

License expiration 10/17/2026

Beginning Fund Balance - Expense + 2% Earnings = Ending Fund Balance

Year [1]	Beginning Fund Balance	Expense [2] 12/31/2009 dollars	2% Earnings	Ending Fund Balance
10/17/2026 [3]	286,249,000	9,819,000	1,136,014	277,566,014
2027	277,566,014	53,297,000	4,485,380	228,754,394
2028	228,754,394	12,862,000	4,317,848	220,210,242
2029	220,210,242	3,739,000	4,329,425	220,800,667
2030	220,800,667	3,739,000	4,341,233	221,402,900
2031	221,402,900	3,739,000	4,353,278	222,017,178
2032	222,017,178	3,746,000	4,365,424	222,636,602
2033	222,636,602	3,734,000	4,378,052	223,280,654
2034	223,280,654	3,734,000	4,390,933	223,937,587
2035	223,937,587	3,734,000	4,404,072	224,607,658
2036	224,607,658	3,745,000	4,417,253	225,279,912
2037	225,279,912	3,734,000	4,430,918	225,976,830
2038	225,976,830	3,734,000	4,444,857	226,687,686
2039	226,687,686	3,734,000	4,459,074	227,412,760
2040	227,412,760	3,745,000	4,473,355	228,141,115
2041	228,141,115	3,734,000	4,488,142	228,895,258
2042	228,895,258	3,734,000	4,503,225	229,664,483
2043	229,664,483	3,734,000	4,518,610	230,449,092
2044	230,449,092	3,745,000	4,534,082	231,238,174
2045	231,238,174	3,734,000	4,550,083	232,054,258
2046	232,054,258	3,710,000	4,566,885	232,911,143
2047	232,911,143	3,710,000	4,584,023	233,785,166
2048	233,785,166	3,720,000	4,601,303	234,666,469
2049	234,666,469	3,710,000	4,619,129	235,575,599
2050	235,575,599	3,710,000	4,637,312	236,502,910
2051	236,502,910	3,710,000	4,655,858	237,448,769
2052	237,448,769	3,720,000	4,674,575	238,403,344
2053	238,403,344	3,710,000	4,693,867	239,387,211
2054	239,387,211	3,710,000	4,713,544	240,390,755
2055	240,390,755	3,710,000	4,733,615	241,414,370
2056	241,414,370	3,720,000	4,753,887	242,448,258
2057	242,448,258	3,710,000	4,774,765	243,513,023
2058	243,513,023	3,710,000	4,796,060	244,599,083
2059	244,599,083	3,710,000	4,817,782	245,706,865
2060	245,706,865	3,720,000	4,839,737	246,826,602
2061	246,826,602	3,710,000	4,862,332	247,978,934
2062	247,978,934	3,710,000	4,885,379	249,154,313
2063	249,154,313	3,710,000	4,908,886	250,353,199
2064	250,353,199	3,720,000	4,932,664	251,565,863

Staff Calculation Using 2% Earnings

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

License expiration 10/17/2026

Beginning Fund Balance - Expense + 2% Earnings = Ending Fund Balance

Year [1]	Beginning Fund Balance	Expense [2] 12/31/2009 dollars	2% Earnings	Ending Fund Balance
2065	251,565,863	3,710,000	4,957,117	252,812,980
2066	252,812,980	3,710,000	4,982,060	254,085,040
2067	254,085,040	3,710,000	5,007,501	255,382,541
2068	255,382,541	3,720,000	5,033,251	256,695,792
2069	256,695,792	3,710,000	5,059,716	258,045,508
2070	258,045,508	3,710,000	5,086,710	259,422,218
2071	259,422,218	3,710,000	5,114,244	260,826,462
2072	260,826,462	3,720,000	5,142,129	262,248,591
2073	262,248,591	3,710,000	5,170,772	263,709,363
2074	263,709,363	3,710,000	5,199,987	265,199,350
2075	265,199,350	3,710,000	5,229,787	266,719,137
2076	266,719,137	3,720,000	5,259,983	268,259,120
2077	268,259,120	3,710,000	5,290,982	269,840,103
2078	269,840,103	3,710,000	5,322,602	271,452,705
2079	271,452,705	14,085,000	5,147,354	262,515,059
2080	262,515,059	52,128,000	4,207,741	214,594,800
2081	214,594,800	101,665,000	2,258,596	115,188,396
2082	115,188,396	81,365,000	676,468	34,499,864
2083	34,499,864	43,658,000	0	(9,158,136)
2084	0	34,244,000	0	(43,402,136)
2085	0	2,233,000	0	(45,635,136)
2086	0	22,580,000	0	(68,215,136)
2087	0	88,000	0	(68,303,136)
2088	0	88,000	0	(68,391,136)
2089	0	24,000	0	(68,415,136)
Total		614,184,000	259,519,864	

Notes:

[1] All years start on Jan. 1, except first year

[2] Expense data provided by licensee

[3] 75 days interest from date of shutdown

Staff Calculation of Surplus (Short)	
Projected 10/17/2026 Balance	286,249,000
Plus Decommissioning Period Earnings	259,519,864
Less Total Cost	614,184,000
Surplus (Short) as of 2009 =	(68,415,136)

Licensee Calculation Using NPV

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

10/17/2026 Projected Fund Balance = 286,233,000

License expiration 10/17/2026

Year	Decommissioning Cost 12/31/2009 dollars	Decommissioning Cost Less Decommissioning Period Credit [1]
2026	9,819,000	9,723,000
2027	53,297,000	51,737,000
2028	12,862,000	12,240,000
2029	3,739,000	3,489,000
2030	3,739,000	3,420,000
2031	3,739,000	3,353,000
2032	3,746,000	3,294,000
2033	3,734,000	3,219,000
2034	3,734,000	3,156,000
2035	3,734,000	3,094,000
2036	3,745,000	3,042,000
2037	3,734,000	2,974,000
2038	3,734,000	2,916,000
2039	3,734,000	2,858,000
2040	3,745,000	2,810,000
2041	3,734,000	2,747,000
2042	3,734,000	2,694,000
2043	3,734,000	2,641,000
2044	3,745,000	2,596,000
2045	3,734,000	2,538,000
2046	3,710,000	2,472,000
2047	3,710,000	2,424,000
2048	3,720,000	2,383,000
2049	3,710,000	2,330,000
2050	3,710,000	2,284,000
2051	3,710,000	2,239,000
2052	3,720,000	2,201,000
2053	3,710,000	2,152,000
2054	3,710,000	2,110,000
2055	3,710,000	2,069,000
2056	3,720,000	2,034,000
2057	3,710,000	1,988,000
2058	3,710,000	1,949,000
2059	3,710,000	1,911,000
2060	3,720,000	1,879,000
2061	3,710,000	1,837,000
2062	3,710,000	1,801,000
2063	3,710,000	1,765,000
2064	3,720,000	1,736,000

Licensee Calculation Using NPV

SAFSTOR Cash Flow ($ 2009)

12/31/2009 Fund Balance = 205,217,000

10/17/2026 Projected Fund Balance = 286,233,000

License expiration 10/17/2026

Year	Decommissioning Cost 12/31/2009 dollars	Decommissioning Cost Less Decommissioning Period Credit [1]
2065	3,710,000	1,697,000
2066	3,710,000	1,664,000
2067	3,710,000	1,631,000
2068	3,720,000	1,603,000
2069	3,710,000	1,568,000
2070	3,710,000	1,537,000
2071	3,710,000	1,507,000
2072	3,720,000	1,481,000
2073	3,710,000	1,448,000
2074	3,710,000	1,420,000
2075	3,710,000	1,392,000
2076	3,720,000	1,369,000
2077	3,710,000	1,338,000
2078	3,710,000	1,312,000
2079	14,085,000	4,883,000
2080	52,128,000	17,716,000
2081	101,665,000	33,873,000
2082	81,365,000	26,578,000
2083	43,658,000	13,982,000
2084	34,244,000	10,752,000
2085	2,233,000	687,000
2086	22,580,000	6,814,000
2087	88,000	26,000
2088	88,000	25,000
2089	24,000	7,000
Total	614,187,000	300,412,000

Decommissioning Period Credit = Decommissioning Cost - Decommissioning Cost Less Decommisioning Credit
313,775,000 = 614,187,000 - 300,412,000

Total Projected Trust Fund Amount = 10/17/2026 Balance + Decommisisoning Period Credit
600,008,000 = 286,233,000 + 313,775,000

Note:

[1] Values are the net present value (NPV) of annual Decommissioning Cost discounted to 2026

Licensee Calculation of Surplus (Short)	
Projected 10/17/2026 Balance	286,233,000
Plus Decommissioning Period Credit	313,775,000
Less Total Cost	614,187,000
Surplus (Short) as of 10/17/2026 =	(14,179,000)
Surplus (Short) as of 12/31/2009 =	(10,166,000)

Proposed Final Section 1.3 of REGULATORY GUIDE 1.159, Revision 2, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors” (Draft was issued as DG-1229)

No change from DG-1229.

Change from RG 1.159, Revision 1 was to update references. See underlined paragraph. Revised sentence listing items outside the scope of the decommissioning process. See underlined text.

1.3 Decommissioning Cost Estimates

Five decommissioning cost estimates are required to be developed and submitted for NRC review:

(1) initial estimate that may be calculated according to 10 CFR 50.75(c), or that may be site-specific and at least equal to the decommissioning cost from 10 CFR 50.75(c);

(2) preliminary decommissioning cost estimate at or about 5 years before the projected end of operations, in accordance with 10 CFR 50.75(f)(2);

(3) estimate of expected costs contained in the PSDAR, in accordance with 10 CFR 50.82(a)(4)(i);

(4) site-specific decommissioning cost estimate within 2 years following permanent cessation of operations, in accordance with 10 CFR 50.82(a)(8)(iii);

(5) updated site-specific estimate of remaining decommissioning costs contained in the license termination plan, in accordance with 10 CFR 50.82(a)(9)(ii)(F).

The NRC developed guidance providing details on content and format for the reporting of these cost estimates and published it in Regulatory Guide 1.202, “Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors,” issued February 2005 (Ref. 8), and in NUREG-1713, “Standard Review Plan for Decommissioning Cost Estimates for Nuclear Power Reactors,” issued December 2004 (Ref. 9).

In general, decommissioning cost estimates are provided by major activity and major decommissioning phase or time period. The cost estimate must account for the entire decommissioning work scope but not for items that are outside the scope of the decommissioning process. Examples of activities outside of decommissioning include, but are not limited to: 1) the maintenance and storage of spent fuel, 2) the design and/or construction of a spent fuel dry storage facility, 3) activities that are not directly related to supporting long-term storage of the facility, or 4) any other activities not directly related to radiological decontamination of the site. If nondecommissioning cost items are included, these items should be identified separately.

Cost estimates should provide costs for each of the following (or similar) major activities and phases with a level of detail appropriate to the type of cost estimate:

(1) major radioactive component removal—reactor vessel and internals, steam generators, pressurizers, large-bore reactor coolant system piping, and other large components that are radioactive to a comparable degree;

(2) radiological D&D—removal of remaining radioactive plant systems, including radiological decontamination;

(3) management and support (undistributed costs)—costs such as labor costs of utility support staff and decommissioning contractor staff, energy costs, regulatory costs, small tools, insurance, etc.;

(4) waste packaging/shipping—placing waste in packages and shipping to waste vendors or burial site;

(5) waste burial or waste vendor—waste burial charges, including waste vendors' processing fees;

(6) contingency—allowance for unexpected costs.

Cost estimates should also include the assumptions, references, and bases for unit costs used in developing the estimates, as well as a description of how inflation is accounted for in the cost estimate. The cost estimate should be provided in current-year dollars. Escalation of the waste disposition costs is considered separately from the general inflation rate applicable to labor, material, and energy costs. Regulatory Position 1.2 discusses escalation factors.

Proposed Final Section 2.1.5 of REGULATORY GUIDE 1.159, Revision 2, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors” (Draft was issued as DG-1229)

Change from DG-1229 was to add a reference to Commission policy requiring adequate financial assurance at all times during the life of the facility, to remove guidance that utility licensees should address decommissioning funding in every rate case, add guidance on good faith effort to obtain rate relief, and rewrite for clarity.

Change from RG 1.159, Revision 1: in addition to changes to DG-1229, increased frequency of covering shortfalls for merchant plant licensees from 2 years to 1 year, and for utility licensees from every 6 years to every 5 years.

2.1.5 A licensee is required to provide assurance that at any time during the life of the facility, through termination of the license, adequate funds will be available to complete decommissioning. See 61 FR 39278. Pursuant to 10 CFR 50.75(b)(1) and (b)(2), the minimum amount of financial assurance required for decommissioning must be adjusted annually, using a rate at least equal to that stated in paragraph (c)(2) of 10 CFR 50.75. The licensee should calculate the amount of the adjustment as of December 31 of each year. If the amount of financial assurance provided by the licensee does not equal or exceed the minimum required amount of financial assurance recalculated on December 31, then the licensee must adjust the amount of financial assurance it provides, such that it meets or exceeds the required amount.

The adjustment in the amount being provided should occur by March 31 of each year, based on the amount of financial assurance as recalculated by the licensee on December 31 of the preceding year. The staff will normally evaluate the amount of financial assurance provided by the licensee in conjunction with the decommissioning funding status report required biennially, or annually in some cases, pursuant to 10 CFR 50.75(f).

However, under the provisions of 10 CFR 50.75(e)(2), the staff reserves the right to review, as needed, the rate of accumulation of decommissioning funds and, either independently or in cooperation with the FERC and the licensee’s State PUC, take additional actions on a case-by-case basis, including modification of the licensee’s schedule for the accumulation of funds.

A licensee that may rely exclusively on an external sinking fund to provide financial assurance under the circumstances defined in 10 CFR 50.75(e)(ii)(A) or (B), that is, where the total cost of decommissioning is provided through rates established by cost-of-service ratemaking or non-bypassable charges, may make a good-faith effort to obtain rate relief to cover its shortfall. A licensee meeting these criteria should inform its rate regulator by March 31 of each year when a shortfall in financial assurance has occurred as of December 31 of the preceding year. The information should include the NRC minimum financial assurance requirement, the actual amount of the licensee’s decommissioning financial assurance, and the amount of additional cost recovery needed to meet the NRC amount. The licensee should request its rate regulator to schedule a review of decommissioning cost recovery by the end of the year. A copy of the information and request should be included in the licensee’s decommissioning fund status report in the years that the report is required. The licensee is expected to obtain rate relief as necessary to meet the minimum requirement of 10 CFR 50.75(c), but in any case, within 5 years.

Proposed Final Section 2.2.8 of REGULATORY GUIDE 1.159, Revision 2, “Assuring the Availability of Funds for Decommissioning Nuclear Reactors” (Draft was issued as DG-1229)

No change from DG-1229.

Changes from RG 1.159, Revision 1:

- Section 2.2.8.1. Delete sentence, “A reasonable time may be used to make up any deficit, consistent with good-faith efforts to obtain rate relief.” See strikethrough text.
- Section 2.2.8.2. Add phrase, “that will provide the total amount of funds necessary for decommissioning.” See underlined text.
- Section 2.2.8.4. Add sentence, “The allowed credit during the period of safe storage must reflect any withdrawals from decommissioning funds during this period, such as withdrawals to pay for annual costs to maintain the facility in a safe storage condition.“ See underlined text.
- Add subsection numbers 2.2.8.1 through 2.2.8.7.

2.2.8 Annual deposits in an external sinking fund, including projected earnings, should attempt to approximate the total amount remaining to be accumulated, divided by the remaining years of the license, as determined by the initial and updated certification amount specified in 10 CFR 50.75(c)(1) and (2).

2.2.8.1 Arithmetic precision is not required for fund accumulation rates. If, during the course of collecting funds, a licensee has accumulated significantly greater decommissioning funds than anticipated, it may reduce its remaining contributions commensurately. Likewise, if a licensee is significantly behind in collections, increased contributions should be used to make up the deficit. ~~A reasonable time may be used to make up any deficit, consistent with good-faith efforts to obtain appropriate rate relief.~~ However, licensees should avoid undue reliance upon contributions weighted in constant dollars toward the end of projected facility operating life. Additionally, the NRC staff considers reliance on an estimated tax deduction for decommissioning expenses, at the time such expenses are incurred, to be a form of internal reserve and thus not allowed under 10 CFR 50.75(e). If sufficient rate relief by a State PUC or FERC is ultimately not obtained, the licensee’s stockholders will be expected to cover decommissioning costs through reduced return on equity. Projected rates of earnings on an external sinking fund during plant operation should reasonably approximate the historical real rate of earnings (i.e., after inflation and taxes) obtained by a given type of investment.

2.2.8.2 For decommissioning funds that are prepaid or in external sinking fund accounts, the regulations in 10 CFR 50.75(e)(i) and (ii) allow a credit for projected earnings of up to a 2 percent annual real rate of return (i.e., nominal rate less inflation and taxes) from the time of the future funds’ collection as a factor in calculating the total amount of funds that would be sufficient to pay decommissioning costs. This allowed credit may be greater than 2 percent if a licensee is subject to a rate-setting authority <u>that will provide the total amount of funds necessary for decommissioning</u> and the authority has specifically presumed a higher rate. The period of time for which the credit may be taken is determined by whether a generic formula or a site-specific estimate with a specified safe-storage period is used as the basis for estimating decommissioning costs, as discussed below.

2.2.8.3 For licensees that use a generic formula for decommissioning cost estimates, during the period of plant operation this credit may be taken for the remaining years left on the operating license, and an additional pro-rata credit may be taken into the presumed immediate dismantlement period (i.e., the first 7 years after shutdown), as long as such credit reflects the expected cash flow of expenditures during this period. If license renewal for a plant has been approved by the NRC, the licensee may take the credit during the extended license period.

2.2.8.4 A licensee that uses a site-specific estimate may take the allowed credit through the projected decommissioning period, provided that the site-specific estimate is based on a period of safe storage that is specifically described in the estimate. This decommissioning period includes the period of safe storage, final dismantlement, and license termination. <u>The allowed credit during the period of safe storage must reflect any withdrawals from decommissioning funds during this period, such as withdrawals to pay for annual costs to maintain the facility in a safe storage condition.</u>

2.2.8.5 When a licensee adjusts the cost estimate for decommissioning annually, pursuant to 10 CFR 50.75(b)(2), the adjusted estimate less amounts already accumulated should form the basis of future collections, which can take into account the allowed credit. Funds already accumulated, plus scheduled fund contributions, in the case of those licensees authorized to utilize external sinking funds, plus projected earnings on these funds, should be sufficient to pay decommissioning costs at the time termination of operation is expected, allowing for extending the real rate of return credit into the decommissioning period, as noted above.

2.2.8.6 Actual earnings on existing funds may be used to calculate the need for future funds. However, pursuant to 10 CFR 50.75(f)(3), when a licensee is within 5 years of the projected end of operations and submits its preliminary decommissioning cost estimate, the licensee may take up to a 2 percent earnings credit (or a higher credit, if specifically presumed by a rate-setting authority) over a storage period, as long as the storage period and its cost implications for total decommissioning costs are specifically addressed in the preliminary decommissioning cost estimate.

2.2.8.7 Licensees who operate multiple modular reactors at a single site may take credit for earnings in such a manner that the assumptions for earnings credit track the cash flows for decommissioning expenses for each module.

Proposed additional definitions for RG 1.159

decommissioning financial assurance – The system of regulation used by the NRC to assure that funds are available when needed for decommissioning. It also refers to the total amount of assurance provided using one or more of the methods specified in 10 CFR 50.75(e). When referring to the total amount of financial assurance, it is the sum of funds accumulated in a segregated account outside the licensee's control; plus the amount of any guarantees provided; plus the projected amounts of earnings on the accumulated funds; plus projected ratepayer collections by utilities; plus projected non-bypassable charges authorized by a rate regulatory agency; plus, for government licensees, the amount provided by a statement of intent; plus projected payments from certain contractual obligations that meet NRC requirements; plus projected earnings on collections, payments, and non-bypassable charges. If applicable, financial assurance may include other methods if the NRC determines that they provide a level of assurance equivalent to the methods of 10 CFR 50.75(e). A licensee is required to provide financial assurance at all times during the life of the facility through termination of the license, that adequate funds will be available to complete decommissioning. (61 FR 39278)

shortfall – Where the amount of financial assurance provided by the licensee is less than the amount of financial assurance required, the difference is the shortfall.