Regulatory Analysis

Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirements

TABLE OF CONTENTS

Page

EXECUTIVE SUMMARY

The Nuclear Regulatory Commission (NRC) is proposing an alternative set of risk-informed requirements that licensees may voluntarily choose in lieu of the current requirements for analyzing the performance of emergency core cooling systems (ECCS) in 10 CFR 50.46. The alternative requirements will enable some licensees to change aspects of facility design and procedures. This complex rulemaking culminates years of study and analysis on the topic of risk-informing technical requirements in Part 50.

This regulatory analysis assesses the potential values and impacts of the final rule. Because the final rule is voluntary, it is difficult to project whether and how different types of licensees may use it. Moreover, the final rule contains new procedures and requirements whose costs cannot be precisely benchmarked. Therefore, the regulatory analysis follows a conservative approach throughout and addresses uncertainty by analyzing three scenarios representing different degrees to which licensees may employ the rule. Based on input from the Boiling Water Reactors (BWR) Owners' Group and the Westinghouse Owners Group, the analysis quantifies values and impacts only for pressurized water reactors (PWRs) and analyzes the potential use of the rule only for power uprates and relaxation of emergency diesel generator (EDG) start times.

The increased ability to uprate should make this an attractive rule for PWRs despite the regulatory costs, which exceed required capital costs at lower uprate levels (at 7.5% uprates, capital costs exceed regulatory costs). The NRC also will incur substantial review and research costs, most of which can be recovered from licensees.

The regulatory analysis considered two types of benefits. The dominant benefit came from increased power generation due to uprating that will displace some of the high cost oil and gas generation and lead to significant cost savings. The expected monetary benefits related to EDGs were much smaller but still significant.

Integrating the values and impacts reveals a final rule with a positive net present value (NPV). The NPV ranges from $279 million to $2.9 billion (7% discount rate) and $568 million to $5.7 billion (3% discount rate). This is a cost-beneficial rule, as measured by the data and assumptions documented in the regulatory analysis.

1. STATEMENT OF THE PROBLEM AND NRC OBJECTIVES

During the last few years, the NRC has had numerous initiatives underway to make improvements in its regulatory requirements that would reflect current knowledge about reactor risk. The overall objectives of risk-informed modifications to reactor regulations include:

(1) Enhancing safety by focusing NRC and licensee resources in areas commensurate with their importance to health and safety;

(2) Providing NRC with the framework to use risk information to take action in reactor regulatory matters; and

(3) Allowing use of risk information to provide flexibility in plant operation and design, which can result in reduction of burden without compromising safety.

In stakeholder interactions, one candidate area identified for possible revision was emergency core cooling system (ECCS) requirements in response to postulated loss-of-coolant accidents (LOCAs). The NRC acknowledges that LOCAs in the larger break size region are considered very rare events. Requiring reactors to conservatively withstand such events focuses attention and resources on extremely unlikely events. This could have a detrimental effect on mitigating accidents initiated by other more likely events. Nevertheless, because of the interrelationships between design features and regulatory requirements, making changes to technical requirements of certain parts of the regulations on ECCS performance has the potential to affect many other aspects of plant design and operation. The NRC has evaluated various aspects of its requirements for ECCS and LOCAs in light of the very low estimated frequency of the large LOCA initiating event.

NRC's regulations and their implementation are largely based on a "deterministic approach," which establishes requirements for engineering margin and quality assurance in design, manufacture, and construction. In addition, it assumes that adverse conditions can exist (e.g., equipment failures and human errors) and establishes a specific set of design basis events (DBEs) for which specified acceptance criteria must be satisfied. Each DBE encompasses a spectrum of similar but less severe accidents. The deterministic approach then requires that the licensed facility include safety systems capable of preventing and/or mitigating the consequences of those DBEs to protect public health and safety. While the requirements are stated in deterministic terms, the approach contains implied elements of probability (qualitative risk considerations), from the selection of accidents to be analyzed to the system level requirements for emergency core cooling (e.g., safety train redundancy and protection against single failure). Those structures, systems or components (SSC) necessary to defend against the DBEs were defined as "safety-related," and these SSCs were the subject of many regulatory requirements designed to ensure that they were of high quality, high reliability, and had the capability to perform during postulated design basis conditions.

Defense-in-depth is an element of NRC's safety philosophy that employs successive measures, and often layers of measures, to prevent accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. Defense-in-depth is used by the NRC to provide redundancy through the use of a multiple-barrier approach against fission product releases. The defense-in-depth philosophy ensures that safety will not be wholly dependent on any single element of the design, construction, maintenance, or operation of a nuclear facility. The net effect of incorporating defense-in-depth into reactor design, construction, maintenance and operation is that the facility or system in question tends to be more tolerant of failures and external challenges.

The LOCA is one of the design basis accidents established under the deterministic approach. If coolant is lost from the reactor coolant system and the event cannot be terminated (isolated) or the coolant is not restored by normally operating systems, it is considered an "accident" and then subject to mitigation and consideration of potential consequences. If the amount of coolant in the reactor is insufficient to provide cooling of the reactor fuel, the fuel would be damaged, resulting in loss of fuel integrity and release of radiation.

A "probabilistic approach" to regulation enhances and extends the traditional deterministic approach by allowing consideration of a broader set of potential challenges to safety, providing a logical means for prioritizing these challenges based on safety significance, and allowing consideration of a broader set of resources to defend against these challenges. In contrast to the deterministic approach, probabilistic risk assessments address a very wide range of credible initiating events and assess the event frequency. Mitigating system reliability is then assessed, including the potential for common cause failures. The probabilistic treatment considers the possibility of multiple failures, not just the single failure requirements used in the deterministic approach. The probabilistic approach to regulation is therefore considered an extension and enhancement of traditional regulation that considers risk (i.e. product of probability and consequences) in a more coherent and complete manner.

The NRC published a Policy Statement on the Use of Probabilistic Risk Assessment (PRA) on August 16, 1995 (60 FR 42622). In the policy statement, the NRC stated that the use of PRA technology should be increased in all regulatory matters to the extent supported by the state of the art in PRA methods and data, and in a manner that complements the deterministic approach and that supports the NRC's defense-in-depth philosophy. PRA evaluations in support of regulatory decisions should be as realistic as practicable and appropriate supporting data should be publicly available. The policy statement also stated that, in making regulatory judgments, NRC's safety goals for nuclear power reactors and subsidiary numerical objectives (on core damage frequency and containment performance) should be used with appropriate consideration of uncertainties.

In addition to quantitative risk estimates, the defense-in-depth philosophy is invoked in risk-informed decision-making as a strategy to ensure public safety because both unquantified and unquantifiable uncertainties exist in engineering analyses (both deterministic analyses and risk assessments). The primary need with respect to defense-in-depth in a risk-informed regulatory system is guidance to determine which measures are appropriate and how good these should be to provide sufficient defense-in-depth.

To implement the Commission Policy Statement, the NRC developed guidance on the use of risk information for reactor license amendments and issued Regulatory Guide (RG) 1.174. This RG provided guidance on an acceptable approach to risk-informed decision-making consistent with NRC's policy, including a set of key principles. These principles include: (1) being consistent with the defense-in-depth philosophy; (2) maintaining sufficient safety margins; (3) allowing only changes that result in only a small increase in core damage frequency or risk (consistent with the intent of NRC's Safety Goal Policy Statement); and (4) incorporating monitoring and performance measurement strategies.

Regulatory Guide 1.174 further clarifies that in implementing the above principles, the NRC expects that all safety impacts of the proposed change are evaluated in an integrated manner as part of an overall risk management approach in which the licensee is using risk analysis to improve operational and engineering decisions broadly by identifying and taking advantage of opportunities to reduce risk; and not just to eliminate requirements that a licensee sees as burdensome or undesirable.

The process described in RG 1.174 is applicable to changes to plant licensing bases. As experience with the process and applications grew, NRC recognized that further development of risk-informed regulation would require making changes to the regulations themselves. In June 1999, NRC decided to implement risk-informed changes to the technical requirements of Part 50. The first risk-informed revision to the technical requirements of Part 50 consisted of changes to the combustible gas control requirements in 10 CFR 50.44; 68 FR 54123 (September 16, 2003).

The NRC also decided to examine the requirements for large break LOCAs. A number of possible changes were considered, including changes to General Design Criteria (GDC) 35 and changes to § 50.46 acceptance criteria, evaluation models, and functional reliability requirements. The NRC also plans to refine previous estimates of LOCA frequency for various sizes of LOCAs to more accurately reflect the current state of knowledge with respect to the mechanisms and likelihood of primary coolant system rupture.

Industry interest in a redefined LOCA was shown by filing of a Petition for Rulemaking (PRM 50-75) by the Nuclear Energy Institute (NEI) in February 2002. Notice of that petition was published in the *Federal Register* for comment on April 8, 2002 (67 FR16654). The petition requested the NRC to amend § 50.46 and Appendices A and K to allow an option [to the double-ended rupture of the largest pipe in the reactor system] for the maximum LOCA break size as "up to and including an alternate maximum break size that is approved by the Director of the Office of Nuclear Reactor Regulation." Seventeen sets of comments were received, mostly from the power reactor industry in favor of granting the petition. A few stakeholders were concerned about potential impacts on defense-in-depth or safety margins if significant changes were made to reactor designs based upon use of a smaller break size. The NRC is addressing the technical issues raised by the petitioner and stakeholders in this rulemaking.

During public meetings, industry representatives expressed interest in a number of possible changes to licensed power reactors resulting from redefinition of the large break LOCA. These include: containment spray system design optimization, fuel management improvements, elimination of potentially required actions for postulated sump blockage issues, power uprates, and changes to the required number of accumulators, diesel start times, sequencing of equipment, and valve stroke times; among others. In later written comments provided after an August 17, 2004, public meeting, the Westinghouse Owners Group concluded that the redefinition of the large break LOCA should have a substantial safety benefit. The NEI submitted comments which included a discussion of six possible plant changes made possible by such a rule. The NEI stated its expectation that all six changes would most likely result in a safety benefit.

The NRC staff requirements memorandum (SRM) of March 31, 2003, on SECY-02-0057, approved most of the staff recommendations related to possible changes to LOCA requirements and also directed the NRC staff to prepare a proposed rule that would provide a risk-informed alternative maximum break size. The NRC began to prepare a proposed rule responsive to the SRM direction. However, after holding two public meetings the NRC found that there were significant differences between stated NRC and industry interests. The original concept in SECY-98-300 for Option 3 was to make risk-informed changes to technical requirements in all of Part 50. The March 2003 SRM, as it related to LOCA redefinition, preserved design basis functional requirements (i.e., retaining installed structures, systems and components), but allowed relaxation in more operational aspects, such as sequencing of EDG loads. The NRC supported a rule that allowed for operational flexibility, but did not support risk-informed removal of installed safety systems and components. Stakeholders expressed varying expectations about how broadly LOCA redefinition should be applied and the extent of changes to equipment that might result, based upon their understanding of the intended purpose of the Option 3 initiative.

To reach a common understanding about the objectives of the LOCA redefinition rulemaking, the NRC staff requested additional direction and guidance from the Commission in SECY-04-0037, "Issues Related to Proposed Rulemaking to Risk-Inform Requirements Related to Large Break Loss-of-Coolant Accident (LOCA) Break Size and Plans for Rulemaking on LOCA with Coincident Loss-of Offsite Power," (March 3, 2004). The Commission provided direction in a SRM dated July 1, 2004. The Commission stated that the staff should determine an appropriate risk-informed alternative break size and that breaks larger than this size should be removed from the design basis event category. The Commission indicated that the rule should be structured to allow operational as well as design changes and should include requirements for licensees to maintain capability to mitigate the full spectrum of LOCAs up to the double-ended guillotine break of the largest reactor coolant system pipe. The Commission stated that the mitigation capabilities for beyond design-basis events should be controlled by NRC requirements commensurate with the safety significance of these capabilities. The Commission also stated that LOCA frequencies should be periodically re-evaluated and should increases in frequency require licensees to restore the facility to its original design basis or make other compensating changes, the backfit rule (10 CFR 50.109) would not apply.

On March 29, 2005, in SECY-05-0052, "Proposed Rulemaking for 'Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirements'", the NRC staff provided a proposed rule to the Commission for its consideration. In an SRM on July 29, 2005, the Commission directed the NRC staff to publish the proposed rule for public comment after making certain changes. The most significant change requested by the Commission was to require that after implementing the alternative § 50.46a requirements, *all* subsequent plant changes made by a licensee would be evaluated by the licensee's risk-informed process to ensure that they met all of the requirements in § 50.46a. Another change requested by the Commission was to address the issue of seismic loading of degraded piping during very large earthquakes and to solicit public comments on the subject.

On November 7, 2005, (70 FR 67598), the proposed rule was published in the *Federal Register* (FR) with a comment period of 90 days. In response to two different stakeholder requests, on January 18, 2006, the NRC extended the public comment period by 30 days to expire on March 8, 2006.

As directed by the Commission in its SRM on SECY-05-0052, the NRC staff addressed the seismic issue by preparing a report entitled “Seismic Considerations for the Transition Break Size” (ML053470439). This report was posted on the NRC’s rulemaking web site and a notice of its availability and opportunity for public comment was published in the FR on December 20, 2005, (70 FR 75501). A public workshop was held on February 16, 2006, to ensure that stakeholders understood the NRC’s intent and interpretation of the proposed rule and two public meetings were held on June 28, 2006, and August 17, 2006, to discuss public comments received on the proposed rule.

After evaluating all written public comments and comments received at the public meetings, the NRC completed draft final rule language that addressed nearly all commenters’ concerns. On October 31 and November 1, 2006, the NRC staff met with the Advisory Committee on Reactor Safeguards (ACRS) to discuss the draft final rule. In a letter dated November 16, 2006, (ML063190465) the ACRS provided its evaluation of the draft final rule. In its November 16, 2006, letter to the Commission, the ACRS recommended that the rule not be issued in its current form. The ACRS recommended numerous changes to the rule, primarily to increase the defense-in-depth provided for large pipe breaks. The NRC staff evaluated the ACRS recommendations, and in SECY-07-0082, “Rulemaking to Make Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirements; 10 CFR 50.46a “Alternative Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,” (May 16, 2007) sought additional guidance from the Commission on the priority of the rule and on the issues raised by the ACRS. In its August 10, 2007, SRM (ML072220595) responding to SECY-07-0082, the Commission approved NRC staff recommendations for a revised priority and approach for addressing the ACRS concerns and completing the final rule. On April 1, 2008, the NRC staff provided the Commission with its planned schedule (ML080370355) for completing the rule.

As the NRC staff modified the rule in response to the ACRS recommendations and the Commission’s direction, numerous substantive changes were made to the requirements in the draft final rule. After considering the extent of these changes, the NRC decided to provide an additional opportunity for public stakeholders to review and submit comments on the revised rule language. The NRC published the supplemental proposed rule on August 10, 2009 (74 FR 40006). In the *Federal Register* document publishing the supplemental proposed rule, the NRC addressed the public comments on the initial proposed rule and explained the bases for all changes made to the rule language.

On August 18, 2009, NEI requested a 120-day extension to the public comment period. The NRC granted the extension request on September 24, 2009, (74 FR 48667) by extending the comment period for all stakeholders until January 22, 2010. The NRC evaluated public comments and prepared a draft final rule which was made publicly available on May 12, 2010 and posted on regulations.gov. The NRC held a public meeting on June 4, 2010 to discuss resolution of public comments and the draft final rule language with stakeholders. The NRC then prepared the final rule.

Because the criteria in NUREG/BR-0058, "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," Rev.4, Section 3.1 are not met, a safety goal evaluation was not performed as part of this regulatory analysis. In accordance with Section 4.3.2 of NUREG/BR-0058, as revised, this regulatory analysis considered the costs of each individual requirement of the rule. However, the benefits of the rule and the overall balancing of costs and benefits were considered in the aggregate because the NRC determined that all of the key requirements of the rule are necessary to ensure reasonable assurance of adequate protection to the public under the alternative requirements governing ECCS. In addition, based upon the cost analysis of the rule's specific requirements, there is no reason to believe that the cost associated with a particular provision of the rule is being masked by the aggregated benefits. Accordingly, the NRC did not prepare a regulatory analysis which disaggregates cost and benefits.

2. ANALYSIS OF ALTERNATIVE REGULATORY STRATEGY

The NRC is establishing an alternative set of risk-informed requirements with which licensees may voluntarily chose to comply in lieu of meeting the current emergency core cooling system requirements in 10 CFR 50.46. Using the alternative ECCS requirements will provide some licensees with opportunities to change aspects of facility design and operations. The overall structure of the risk-informed alternative is described below.

This rulemaking will apply to operating plants and to new reactor designs that are demonstrated to be similar to existing operating reactors. The rule will establish risk-informed LOCA break sizes[1] (smaller than the double-ended guillotine break (DEGB) of the largest reactor coolant system pipe) to divide the current spectrum of LOCA break sizes into two regions, which are delineated by a "transition" break size (TBS). The first region includes small size breaks up to and including the TBS. The second region includes breaks larger than the TBS up to and including the DEGB of the largest reactor coolant system pipe.

Pipe breaks in the smaller break size region are considered more likely than pipe breaks in the larger break size region. Consequently, each region will be subject to different ECCS requirements, commensurate with the relative likelihood of the breaks in each region. LOCAs in the smaller break size region will continue to be analyzed by current methods, assumptions, and criteria.

Based on their lower likelihood, accidents in the larger break size region will be analyzed by less stringent methods. Although loss-of-coolant accidents for break sizes larger than the transition break will become "beyond design-basis accidents," the NRC will include requirements ensuring that licensees maintain the ability to mitigate all LOCAs up to and including the DEGB of the largest reactor coolant system pipe.

[1] Different transition break sizes (diameters) for PWRs and BWRs are being established due to the differences in design between these two types of reactors.

Licensees who perform the new LOCA analyses using the risk-informed alternative requirements may find that their plant designs are no longer limited by certain parameters associated with previous DEGB analyses. Reducing the DEGB limitations could enable licensees to propose a wide scope of design or operational changes. Potential design changes include optimization of containment spray designs, increasing power, modifying core peaking factors, optimizing setpoints on accumulators or removing some from service, eliminating fast starting of one or more EDGs, etc. Some of these design and operational changes could increase plant safety, since a licensee could optimize its systems to mitigate the more likely LOCAs. The risk-informed § 50.46a option will establish criteria for evaluating design changes. The criteria will be consistent with the criteria for risk-informed license amendments contained in Regulatory Guide 1.174. These criteria ensure both the acceptability of the changes from a risk perspective and the maintenance of sufficient defense-in-depth.

The rule also will require that facility changes be reviewed and approved by the NRC via the routine process for risk-informed license amendments,[2] including any needed changes to the facility's technical specifications, except for certain plant changes that have such a minimal impact on risk that licensees will be allowed to make them without NRC review or approval. Potential impacts of plant changes on facility security would be evaluated as part of the license amendment review process.

The NRC periodically will evaluate LOCA frequency information. If estimated LOCA frequencies significantly increase, the NRC will undertake rulemaking (or issue orders, if appropriate) to change the transition break size. In that case, the backfit rule (10 CFR 50.109) would not apply. As the result of changing the transition break size, some licensees might be required to take appropriate action to modify their facilities in order to restore compliance with § 50.46a requirements. In these cases, the backfit rule (10 CFR 50.109) would not apply.

BACKFIT CONSIDERATION

The NRC has determined that the final 10 CFR 50.46a and the conforming changes in 10 CFR parts 50 and 52 generally do not constitute backfitting as defined in the backfit rule, 10 CFR 50.109(a)(1), or are otherwise in conflict with the various issue finality provisions in part 52. In addition, the NRC has determined that three provisions of the rule which exclude certain NRC actions from the purview of the backfit rule, *viz*., § 50.109(b)(2); § 50.46a(d)(4), and § 50.46a(m), are appropriate. The basis for each of these determinations is detailed in the Backfit Analysis section of the *Federal Register* notice for the final rule (ADAMS Accession no. ML103260109).

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[2] The administrative requirements governing NRC processing of license amendments are specified in 10 CFR 50.90. They include public notice of all amendment requests in the *Federal Register*, an opportunity for affected persons to request a public hearing, preparation of an environmental analysis, and a detailed NRC technical evaluation to ensure that the facility will continue to provide adequate protection of public health and safety after the amendment is implemented.

3. ESTIMATION AND EVALUATION OF VALUES AND IMPACTS

3.0 Overview

This section describes the analysis conducted to identify and evaluate the benefits (values) and costs (impacts) of the rule. Section 3.1 identifies the attributes that the rulemaking is expected to affect. Section 3.2 describes the baseline used to analyze the benefits and costs associated with changes to the affected attributes. Section 3.3 presents the impacts of the rule, while Section 3.4 presents the benefits.

3.1 Identification of Affected Attributes

This section identifies the factors that affect the public and private sectors as a result of the rulemaking. These factors are classified as "attributes" using the list of potential attributes provided in Chapter 5 of the NRC's "Regulatory Analysis Technical Evaluation Handbook."[3] Each attribute listed in Chapter 5 was evaluated, and the basis for selecting those attributes expected to be affected by the potential action is presented in the balance of this section.

- *Industry Implementation*. The regulatory action will require licensees to prepare and submit ECCS re-analyses for LOCAs at or below and LOCAs above the TBS, risk-informed assessments, and license amendment applications to support changes to design, operations, and technical specifications.

- *Industry Operation*. Licensees will need to update their PRAs periodically, submit reports, and perform annual monitoring of approved changes. In addition, licensees may need to implement corrective actions as necessary to ensure compliance with all applicable regulatory requirements. Licensees are expected to incur significant operational benefits from the opportunities provided by the rule, both in cost savings as well as revenue enhancements.

- *NRC Implementation*.[4] In order to implement the regulatory action, the NRC will review ECCS re-analysis and risk-informed information submitted by licensees and conduct the license amendment process. NRC also will develop one or more Regulatory Guides for the final rule.

- *NRC Operation*. The action would require NRC inspections of facility changes, review of PRA updates, and evaluation of LOCA frequency information.

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[3]NUREG/BR-0058 Revision 4, "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, September, 2004.

[4] Consistent with direction in Section 5.7.9 of the NRC's " Regulatory Analysis Technical Evaluation Handbook," this analysis does not include the predecisional costs of analyzing and promulgating the proposed requirements.

- *Regulatory Efficiency*. The action would enhance regulatory efficiency by reducing attention on very-low probability accident scenarios.

- *Improvements in Knowledge*. The rule will require licensees to use acceptable PRAs or other risk assessment techniques and update them periodically.

- *Other Considerations*. The rule could affect public confidence in the NRC. The rule could increase public confidence of those individuals who view it as focusing the application of NRC and licensee resources away from the less risk-significant accidents toward the more risk-significant accident scenarios. Alternately, although NRC believes that meeting the generic acceptance criteria will maintain an adequate level of safety; the public may perceive the new rule's flexibility as providing less assurance of safety. Consequently, the public may perceive NRC to be unnecessarily relaxing safety standards.

The rulemaking is not expected to affect the following attributes:

- *Environmental Considerations*
- *General Public*
- *Public Health (Routine)*
- *Other Government*
- *Occupational Health (Routine)*
- *Safeguards and Security Considerations*

The NRC anticipates that the rulemaking would have insignificant effects on the following attributes:

- *Public Health (Accidental)*
- *Occupational Health (Accidental)*
- *Offsite Property*
- *Onsite Property*

The magnitudes of the risk increases and associated public health and property impacts caused by plant modifications to increase licensed power and modify EDG start time are highly plant-specific. The NRC has not attempted to quantify the level of these potential increases. Because § 50.46a(f)(2)(ii) would permit an increase in accident risk of no more than very small (approximately 10^{-6} per year in CDF and 10^{-7} per year in LERF), the NRC expects that accident-related costs associated with the above attributes will be offset by the increased power generation.

Industry implementation/operation and NRC implementation/operation are evaluated quantitatively. Quantitative analysis requires a baseline characterization of factors such as the number of licensees anticipated to take advantage of the rule, the cost to prepare and review a § 50.46a request, and the economic benefits of uprates and delayed EDG start-times.

3.2 Baseline for Analysis

This regulatory analysis estimates the incremental benefits and costs of the rulemaking relative to a baseline, which is how the world would be if the regulation were not imposed. The regulation is applicable to both pressurized water reactors (PWRs) and boiling water reactors (BWRs). However, NRC expects that PWRs will be the primary beneficiaries. The NRC expects that most PWRs may be able to uprate power, depending upon plant-specific equipment capabilities, such as steam generator capacity, and also may be able to extend EDG start times. The Westinghouse Owners Group (WOG) has identified Redefinition for LOCAs above the TBS as the highest priority regulatory issue facing the industry since 2000 and reiterated that position in its response to the questions raised at the August 17, 2004, public meeting. Although the WOG did not survey its membership to determine how many would take advantage of redefinition for LOCAs above the TBS, it expected that most PWRs (>75%) will ultimately perform one or more applications, such as power uprates and relaxation of EDG start times. BWRs, which tend not to be LOCA-limited, may not be able to uprate power but may be able to relax technical specifications and reduce analysis as well as operations and maintenance costs. The BWR Owners' Group, in comments submitted in response to the questions raised at the August 17, 2004 meeting, identified no potential values at the TBS and added that it was extremely difficult to evaluate the cost-benefit of the rule, independent of any value that could be gained, due to uncertainties about the true costs of adopting the rule. Accordingly, this regulatory analysis focuses solely on PWRs.

The NRC staff assumes that all 69 pressurized water power reactor licensees will seek and obtain license renewals. This is consistent with NUREG/BR-0058, "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," Rev. 4, which states that, "… estimates for a license renewal term should be made if the analyst judges that the results of the regulatory analysis could be significantly affected by the inclusion of such a renewal term."

The construction of new pressurized water power reactors is possible but uncertain. For the purposes of this analysis, it is assumed that any new reactors will not benefit from the regulation. This assumption is based on uncertainty regarding when new reactors will be constructed and the extent of the benefits available from the regulation given the use of new designs.

Section 3.3 presents the estimated incremental costs and Section 3.4 presents the estimated incremental benefits associated with the rule relative to this baseline. The benefits of the rule include any desirable changes in affected attributes while the costs include any undesirable changes in affected attributes.

NRC believes that the most likely benefit from the rule change appears to be the potential for PWRs to seek power uprates to generate additional electricity. Since 1977, NRC staff have approved 76 power uprate license amendments for PWRs. These license amendment applications have been filed by 58 of the 69 PWRs (84 percent). Sixteen PWRs have received power uprate license amendments more than once:

- Beaver Valley 1 (1.4 percent and 8 percent)
- Beaver Valley 2 (1.4 percent and 8 percent)
- Comanche Peak 1 (1.4 percent and 4.5 percent)

•	Comanche Peak 2	(1 percent, 0.4 percent, and 4.5 percent)
•	Crystal River 3	(0.9 percent and 1.6 percent)
•	H.B. Robinson	(4.5 percent and 1.7 percent)
•	Indian Point 2	(1.4 percent and 3.3 percent)
•	Indian Point 3	(1.4 percent and 4.9 percent)
•	Kewaunee	(1.4 percent and 6 percent)
•	Palo Verde 1	(2 percent and 2.9 percent)
•	Palo Verde 2	(2 percent and 2.9 percent)
•	Palo Verde 3	(2 percent and 2.9 percent)
•	Salem 1	(2 percent and 1.4 percent)
•	Seabrook	(5.2 percent and 1.7 percent)
•	Vogtle 1	(4.5 percent and 1.7 percent)
•	Vogtle 2	(4.5 percent and 1.7 percent)

Power uprates by PWRs have ranged from 0.4 percent to 16.8 percent. The most frequently requested power uprate level among the 59 approved uprates is 1.4 percent, which occurred 16 times. The average power uprate level granted to PWRs is 3.5 percent, while the median power uprate level is 2.9 percent.

Eleven PWRs (representing approximately 16 percent of all PWRs) have yet to receive power uprate license amendments:

- Arkansas Nuclear 1
- Catawba 1
- Catawba 2
- Diablo Canyon 2
- McGuire 1
- McGuire 2
- Oconee 1
- Oconee 2
- Oconee 3
- Prairie Island 1
- Prairie Island 2

As of January 2009, NRC staff are reviewing two power uprate license amendments for PWRs. Due to the uncertainty associated with these pending uprates, NRC excluded them from the baseline used for this regulatory analysis:

- Calvert Cliffs 1 (1.4 percent)
- Calvert Cliffs 2 (1.4 percent)

In this regulatory analysis, the values and impacts associated with future power uprates are calculated based on three scenarios that could result from the rule change. The power uprate scenarios were developed by the NRC staff based on the history discussed above (e.g., 84 percent of PWRs have received uprates ranging from 0.4 percent to 16.8 percent, with an average of 3.5 percent and median of 2.9 percent), ongoing research and analysis, and other expertise available in published literature. The scenarios are defined in Exhibit 1.

Exhibit 1
SUMMARY OF POWER UPRATE SCENARIOS

Scenario	Degree of Power Uprate	Participating Plants
1	1%	18
2	3%	18
3	10%	14

Scenario 1 is based on the regulatory analysis related to the revision of Appendix K, 10 CFR Part 50.[5] In the Appendix K analysis, NRC assumed that all nuclear power reactors would be able to achieve a power uprate of 1 percent. However, based on input from industry and the voluntary nature of the regulation, NRC assumed that roughly 25 percent of PWRs, or 18 PWRs, would take advantage of the regulation. NRC staff believes that this scenario is a realistic lower bound for the rule change currently under consideration.

The assumptions for Scenario 2 are based on formal comments made by industry and the Westinghouse Owners' Group (WOG) regarding the § 50.46 rule change. In a published interview, an NEI staff member predicts "power uprates on the order of 3 percent."[6] The WOG, in its comments in response to the questions raised in the August 17, 2004 public meeting, stated that, depending on how the revised rule is written, up to 25 percent of PWRs would use the new § 50.46a rule to achieve a 2.5% power uprate. NRC believes it is quite plausible that 25% percent of PWRs will be able to achieve a 3 percent uprate. Based on NRC's assumption of PWR participation, 18 PWRs, or 25 percent of total PWRs, would take advantage of the regulation for a 3 percent uprate.

Scenario 3 serves as an upper bound for the anticipated power uprates in this regulatory analysis. Although NRC staff believes that the rule change will result in power uprates of up to 10 percent, it is not known how many reactors will actually be able to accomplish that level of power uprate. Based on NRC's conservative assumption, 14 PWRs, or 20 percent of total PWRs, will take advantage of the regulation for a 10 percent uprate. Although power uprates greater than 10 percent also may be feasible, Scenario 3 is considered a realistic upper bound for the uprate values and impacts NRC expects to result from this rule change.

This analysis also assumes that licensees applying for a license amendment to uprate power will simultaneously seek reductions to their EDG start times. However, licensees are not expected to incur the costs of § 50.46a solely to secure the benefits of relaxed EDG start times. Therefore, the rates of PWR's seeking relaxed EDG start times were assumed to be identical to the three scenarios enumerated above (e.g., 18 PWRs, 18 PWRs, 14 PWRs).

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[5] U.S. Nuclear Regulatory Commission, "Regulatory Analysis for Revision of 10 CFR Part 50, Appendix K." September 23, 1999.

[6] Knapik, M. "Industry, Seeing Huge Benefits, Presses for Redefining Large-Break LOCA," *Inside NRC* (January 15,2001.4)

Appendix A further describes the methodology and data used to analyze quantitatively the benefits associated with the rule.

3.3 Analysis of the Impacts

3.3.1 Impacts to Licensees

Unit Regulatory Costs. The PWRs will incur implementation costs associated with pursuing power uprates and relaxed start times for EDGs through § 50.46a. To achieve the benefits associated with this rule change, a PWR must submit a § 50.46a package and license amendment request to NRC. To ensure that safety is not compromised, NRC requires documentation from the licensee to support the risk-informed changes. As a result, the licensee is subject to costs associated with providing these supporting analyses. NRC staff assume that these costs will begin to accrue to industry following the promulgation of the final rule in June 2010 (estimated) and will continue for several years.

(a) Initially, to take advantage of the rule, a licensee must conduct ECCS re-evaluations separately for LOCAs at or below and LOCAs above the TBS that meet applicable requirements and acceptance criteria. The NRC estimates that an ECCS process requires 2,500 hours of industry staff/consultant time.[7] To complete separate ECCS evaluations for LOCAs at or below and LOCAs above the TBS, 3,750 hours are estimated. At an average labor rate of $238 per hour (2008$), the NRC estimates that this activity will cost $892,500 (i.e., 3,750 hours x $238 per hour) over a several month period for each submission. The $238 per hour labor rate is the current amount that NRC charges per hour to licensees for NRC review of various documents.

(b) The next step is preparing the risk-informed assessment. Analysis of safety margins, defense-in-depth, equipment reliability, risk estimates, and a PRA[8] of large break LOCA frequencies (or other type of risk assessment) must be performed under the assumption that the plant changes have been implemented. The NRC expects that this process will require 1900 person-hours of industry staff time and 600 hours of contractor support time. Using an average labor rate of $238 per hour both for industry and its contractors, the NRC estimates the cost of this engineering analysis to be $595,000 (i.e., (1,900 hours + 600 hours) x $238 per hour). For this analysis, it is assumed these costs will be incurred over an eight-month period.

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[7] *OMB Supporting Statement for Acceptance Criteria for Emergency Core Cooling Systems (ECCS): 10 CFR 50.46 and Appendix K (Section 7).*

[8] The licensee will need to address PRA quality issues. At a minimum, licensees will need to have a PRA that reflects the current plant configuration, is sufficiently complete for the intended application, meets a quality standard (RG 1.200), and is up-to-date. Depending on the state of the licensee's PRA, this activity could involve a significant commitment in resources. NRC notes that many licensees have already made investments in development of a PRA and having the PRA peer-reviewed for use in various applications, such as implementation of Section 50.65(a)(4) and new § 50.69. Some licensees who choose to implement this risk-informed alternative already may have incurred many of these costs and would be interested in additional opportunities for using the PRA.

(c) The rule will require that proposed facility changes be reviewed and approved by the NRC as risk-informed applications in accordance with the existing license amendment process, including any needed changes to the facility's technical specifications. Potential impacts of the changes on facility security will be evaluated as part of the process for performing license amendment reviews. In addition, the application will be reviewed to ensure that any changes to onsite physical protection systems and security organizations needed to maintain high assurance that activities involving nuclear material are not inimical to the common defense and security and do not constitute an unreasonable risk to the public health and safety are identified. Alternatively, a justification of why changes are not needed must be provided. NRC has previously estimated a licensee burden of 384 hours for a license amendment under § 50.59, 50.90, or 50.91. At an average labor rate of $238 per hour, the NRC estimates that this licensing process will cost a licensee $91,392 (i.e., $238 per hour x 384 hours).

(d) In order to ensure equipment and SSCs continue functioning properly if changes to a plant have been made, and to retain proper documentation of all plant changes and the effects of those changes, a licensee must create and maintain a comprehensive continuous monitoring program. The NRC estimates that design and planning of a monitoring program specifically for plant alterations and documentation in line with the new rule will require 850 person-hours of staff time. Likewise, the NRC estimates that a licensee will incur an additional annual monitoring burden of 1150 person-hours of staff time to oversee changes related to the new risk-informed rule. The NRC estimates this additional monitoring burden will cost a licensee $273,700 annually (i.e., 1150 hours x $238 per hour) after a one-time cost of $202,300 (i.e., 850 hours x $238 per hour) to design the monitoring plan over a three-month period. For the purposes of this regulatory analysis, these annual costs will accrue until the year 2054, when the last PWR license is set to expire.

(e) To satisfy the requirements of § 50.46a(d)(6), licensees will need to evaluate all proposed changes to a facility before such changes are implemented to ensure that the change does not invalidate the evaluation performed pursuant to paragraph (c)(1)(i) demonstrating the applicability to the licensee's facility of the generic studies performed in NUREG-1829, "Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process," March 2008, and NUREG-1903, "Seismic Considerations for the Transition Break Size," February 2008, that support the technical basis for this section. NRC estimates that the evaluation will require 550 licensee person-hours annually. At an average labor rate of $238 per hour, each evaluation will cost a licensee $130,900 (i.e., 550 hours x $238/hour).

(f) To implement § 50.46a, licensees will incur impacts that result from the need to periodically (every other refueling outage) re-evaluate and update risk assessments to reflect subsequent changes to the plant, operational practices, equipment performance, changes in the model, and other factors. NRC believes that licensees have already developed much of this infrastructure in order to comply with the PRA quality guidance being implemented in support of the maintenance rule. NRC estimates that the update will require 200 licensee person-hours and 200 contractor hours every three years. At an average labor rate of $238 per hour, each update will cost a licensee $95,200 (i.e., 400 hours x $238/hour). For the purposes of this regulatory analysis, these recurring costs will accrue until the year 2052, the last year the update will be necessary before the expiration of the last PWR license in 2054.

(g) Licensees should design, purchase, and install local monitoring equipment for critical components of the RCPB for leaks. NRC estimates that, on average, the monitoring will cost each licensee $100,000. For the purposes of this analysis, it is assumed that the monitoring will require 315 licensee person-hours, and $25,000 in capital expenditures.

(h) The rule will require licensees to evaluate the capabilities of leakage monitoring systems to ensure effective management of leakage. NRC estimates that this evaluation will require 210 licensee person-hours. At an average labor rate of $238 per hour, each evaluation will cost a licensee $50,000 (i.e., 210 hours x $238/hour).

(i) To implement § 50.46a, licensees will need to modify plant technical specifications to ensure that all non safety equipment credited in the analysis of breaks larger than the TBS is listed in the technical specifications. NRC estimates modifying technical specifications will require 210 licensee person-hours. At an average labor rate of $238 per hour, each modification will cost a licensee $50,000 (i.e., 210 hours x $238/hour).

(j) During maintenance and refueling outages, licensees should take actions to identify the source of any unidentified leakage that was detected during plant operation. Licensees should take corrective action to eliminate the condition resulting in the leakage. NRC estimates that revising procedures during maintenance and refueling outages will require 84 person-hours. At an average labor rate of $238 per hour, each modification will cost a licensee $20,000 (i.e., 84 hours x $238/hour). For the purposes of this analysis, it is assumed that all plants will modify procedures.

(k) To implement § 50.46a(c), licensees will need to prepare a written evaluation demonstrating applicability of results in NUREG-1829 and NUREG-1903 to the licensee's facility. Under § 50.46a(c)(1)(i), for facilities that differ significantly from plants analyzed in NUREG-1903, the licensee's application must contain a plant specific analysis to demonstrate that the risk of seismically-induced LOCAs larger than the transition break size is less than or comparable to the seismically-induced LOCA risk reported in NUREG-1903. NRC estimates that preparing the applicability evaluation will require 1,500 person-hours. At an average labor rate of $238 per hour, each evaluation will cost a licensee $357,000 (i.e., 1,500 hours x $238/hour).

Total upfront plant-specific implementation would cost $2,358,192 per application, as depicted in Exhibit 2. For comparison purposes, in its September 16, 2004, submission, WOG estimated an implementation cost between $700K and $1 million per unit, plus up to $500,000 ($787,176, $1,124,537, and $562,268 in 2008$ respectively) per licensee for new thermal-hydraulic analyses for breaks larger than the transition break size.

Exhibit 2
SUMMARY OF § 50.46a UNIT COSTS TO LICENSEES
(2008$)

Activity	Burden	Estimated Cost
ECCS Re-Analysis	3,750 hours	$892,500
Risk-Informed Assessment	2,500 hours	$595,000
Develop Monitoring Plan	850 hours	$202,300
License Amendment Process	384 hours	$91,392
Design, Install Monitoring Equipment	315 hours	$75,000
Local Monitoring Equipment	Capital expenditure	$25,000
Evaluate Systems Capabilities	210 hours	$50,000
Modify Technical Specifications	210 hours	$50,000
Modify Procedures	84 hours	$20,000
Prepare Applicability Evaluation	1500 hours	$357,000
	Upfront Implementation Total	$2,358,192
PRA Updates	400 hours/@3 years	$95,200/@3 years
Evaluate Proposed Changes	550 hours/year	$130,900/year
Implement Monitoring	1150 hours/year	$273,700/year

Uprate Capital Costs. Licensees will incur capital costs associated with the plant modifications needed to uprate PWRs; however, relaxation of EDG start times requires no significant additional capital. Following NRC's approval for license modification, PWRs will require upgrades in order to achieve the power uprate. These upgrades can range from minor to major plant modifications. For the purposes of the regulatory analysis, NRC staff assume that license amendment approvals will be spread over a three-year period, reflecting the assumption that NRC staff approve one-third of all power uprate requests per year. Therefore, upfront capital costs will accrue to licensees in 2010, 2011, and 2012.

In general, the larger the power uprate, the greater the capital investment necessary to achieve the higher power level. As a result, NRC assumes that the power uprates from Scenarios 1 and 2 associated with this rule change will require capital costs that range from $206 per kilowatt to $460 per kilowatt (2008$).[9] This range of costs is typical of a stretch power uprate. NRC estimates that Scenario 1 will add about 153,000 kW[10] to nuclear electricity generation by 2013, while Scenario 2 will add 406,000 kW. Scenario 3 assumes that 75 percent of the participating PWRs will achieve a higher power uprate (10 percent); generally, power uprates at this level

[9] Renwick, B. "Nuclear Station Performance Fuels Industry Renaissance." *Power*. July/August, 2001.

[10] Estimates for additional kW are based on a baseline average PWR capacity of 950,000 kW, and assuming PWRs operate at full capacity 95 percent of the time.

require higher capital costs. Therefore, NRC has assigned larger unit capital cost estimates (in 2008$) to Scenario 3 ($500/kW to $825/kW).[11] NRC estimates that Scenario 3 will add 1.17 million kW to baseline nuclear electricity generation by 2013. For the purposes of this regulatory analysis, NRC staff conservatively chose the upper bound of each unit cost range to estimate total capital costs associated with power uprates. Exhibit 3 contains the estimated capital costs associated with power uprates for all licensees according to the three scenarios, calculated by multiplying the unit cost per kilowatt by the total number of kilowatts added, assuming an equal number of kilowatts added in 2010, 2011, and 2012.

Exhibit 3
TOTAL UPFRONT INDUSTRY CAPITAL COSTS OF POWER UPRATES
(millions 2008$)

		Expected Years of Implementation	Estimated Cost All Licensees
Capital Costs	Scenario 1	2011 - 2012 - 2013	$75
	Scenario 2	2011 - 2012 - 2013	$199
	Scenario 3	2011 - 2012 - 2013	$1,043

Accordingly, Exhibit 4 contains the net present value of total capital costs for the three power uprate scenarios discussed in the regulatory analysis. The net present value is calculated using both a 3 percent and 7 percent discount rate.

[11] Renwick, B. "Nuclear Station Performance Fuels Industry Renaissance." *Power*. July/August, 2001.

Exhibit 4
NPV OF INDUSTRY CAPITAL COSTS OF POWER UPRATES
(millions 2008$)

		Estimated NPV **3 % discount rate** **7 % discount rate**
Capital Costs All Licensees	Scenario 1	\$66 \$57
	Scenario 2	\$177 \$152
	Scenario 3	\$927 \$797

<u>Relaxation of EDG Start Times</u>. The regulatory analysis considers scenarios described in Section 3.2, where 75 percent to roughly 100 percent of the participating PWRs apply for power uprates while simultaneously seeking relaxation of EDG start times. This assumption differs from the WOG expectation that (depending on how the revised rule is written) a greater portion (50 percent) of PWRs will seek changes in EDG start times than will seek power uprates. Given the initial costs of applying for § 50.46a, this analysis assumes that a licensee would seek both power uprate and EDG benefits in the absence of other constraints. EDG benefits alone are not likely to be worth the costs to licensees, based on commercial discount rates.

In this regulatory analysis, the values and impacts associated with EDG start time relaxation are therefore calculated using three plausible scenarios that could result from the rule change, defined as follows:

Exhibit 5
SUMMARY OF EDG START TIME RELAXATION SCENARIOS FOR PWRS

Scenario	**Degree of Participation**
1	25%
2	25%
3	20%

Each EDG scenario corresponds to the power uprate scenario described in 3.2. PWRs not applying for power uprates are assumed in this analysis to also not apply for relaxation of EDG start times.

The PWRs will incur costs associated with pursuing the EDG start-time relaxations. For the purposes of this regulatory analysis, the industry's costs include:

- Implementation costs associated with preparing EDG start-time relaxation requests; and
- Operating costs associated with monitoring changes related to EDG start-time relaxations.

There are no significant capital costs associated with plant modifications related to relaxation of EDG start-time requirements.

To achieve the benefits associated with EDG start-time changes resulting from this rule, a PWR must submit a § 50.46a package and license amendment request to NRC. To ensure that safety is not compromised, NRC requires documentation from the licensee to support the EDG start-time relaxation. As a result, the licensee is subject to costs associated with providing these supporting analyses. By piggy-backing on the § 50.46a package for power uprates, each licensee can use the same ECCS re-analysis, avoiding incurring a cost of $892,500. However, the other elements of the application listed in sections 3.3.1(b)-3.3.1(j) must be tailored to this set of changes, excluding the costs of local monitoring equipment which is not an analytical cost, or $100,000, and the regulatory analysis does not assume any "learning curve" cost avoidance because the applications occur concurrently. The up-front cost per licensee for requesting relaxation of EDG start times was then calculated by subtracting the costs for the ECCS re-analysis and the local monitoring equipment from the total up-front costs for requesting power uprates (i.e., $2,358,192 - $892,500 - $100,000). This calculation results in a total up-front cost per licensee for requesting relaxation of EDG start times of $1,365,692 (2008$). This impact is expected to accrue to licensees through 2011, assuming the rule change is effective in June 2010.

The three scenarios result in estimated implementation costs shown in Exhibit 6.

Exhibit 6
SUMMARY OF UPFRONT IMPLEMENTATION COSTS FOR EDG START TIME RELAXATION REQUESTS (2008$)

Category		Expected Year of Implementation	Estimated Cost
License Amendment Request Costs	Scenario 1	2010	$24,582,456
	Scenario 2	2010	$24,582,456
	Scenario 3	2010	$19,119,688

Summary. NRC assumes that licensees must conduct all the activities, with the exceptions of the ECCS re-analysis and designing and installing local monitoring equipment, twice to account for power uprates and EDG start time relaxation applications. NRC believes this is a conservative approach to estimating the impacts on the industry. Exhibits 7 and 8 display the total net present value, discounted at 3% and 7% respectively, of the total industry burden for all activities required to implement the new rule and benefit from both power uprates and EDG start time relaxation.

Exhibit 7
NPV SUMMARY OF IMPACTS TO INDUSTRY @ 3% Discount Rate (millions 2008$)

Activity	Scenario 1	Scenario 2	Scenario 3
ECCS Re-analysis	$15.14	$13.46	$11.78
Risk-Informed Assessment	$20.19	$17.95	$15.7
Implementation & Monitoring Plan	$6.86	$6.1	$5.34
License Amendment	$3.1	$2.76	$2.41
Design/Install Monitoring Equipment	$1.7	$1.51	$1.32
Evaluate Capabilities	$1.7	$1.51	$1.32
Modify Tech Specifications	$1.7	$1.51	$1.32
Modify Procedures	$.68	$.6	$.53
Prepare Applicability Evaluation	$12.11	$10.77	$9.42
Capital Costs	$66	$177	$927
Subtotal (Upfront costs)	**$130**	**$233**	**$976**
Monitoring Program	$234.55	$208.49	$182.43
Evaluate Proposed Changes	$56.09	$56.09	$43.62
PRA Reassessments	$24.48	$21.76	$19.04
Total	***$445***	***$513***	***$1,221***

Exhibit 8
NPV SUMMARY OF IMPACTS TO INDUSTRY @ 7% Discount Rate (millions 2008$)

Activity	Scenario 1	Scenario 2	Scenario 3
ECCS Re-analysis	$14.03	$12.47	$10.91
Risk-Informed Assessment	$18.71	$16.63	$14.55
Implementation & Monitoring Plan	$6.36	$5.65	$4.95
License Amendment	$2.87	$2.55	$2.24
Design/Install Monitoring Equipment	$1.57	$1.4	$1.22
Evaluate Capabilities	$1.57	$1.4	$1.22
Modify Tech Specifications	$1.57	$1.4	$1.22
Modify Procedures	$.63	$.56	$.49
Prepare Applicability Evaluation	$11.23	$9.98	$8.73
Capital Costs	$58	$152	$797
Subtotal (Upfront costs)	**$116**	**$204**	**$842**
Monitoring Program	$125.29	$111.37	$97.45
Evaluate Proposed Changes	$29.96	$29.96	$23.30
PRA Reassessments	$12.49	$11.1	$9.71
Total	***$283***	***$398***	***$973***

3.3.2 Impacts to NRC

In implementing the regulatory action, the NRC expects to incur costs from performing regulatory review and research activities.

(a) Activities involved in processing applications under § 50.46a include the following:
- review of the ECCS re-analyses;
- proposed plant modifications (e.g., for power uprates and relaxation of EDG start times) and their anticipated effects on SSCs, safety margins, and defense-in-depth measures;
- licensee plans for monitoring plant operations and equipment, and changes in risk estimates (CDF (core damage frequency) and LERF (large early release frequency));
- changes to licensee technical specifications pursuant to 10 CFR 50.36; and
- the scientific validity of the PRA performed by the licensee which encompasses the proposed plant changes.

The NRC estimates that the staff burden for reviewing applications for changes to the licensing basis will depend on the size of the requested power uprate.[12,13] Therefore, NRC has calculated

[12] *Final OMB Supporting Statement for PRA in Risk Informed Decisions on Plant-Specific Changes to the Current Licensing Basis* (Sections 33, 3150-0011).

[13] U.S. Nuclear Regulatory Commission, "Status Report on Power Uprates," *SECY-04-0104*, June 24, 2004.

three distinct review burdens for the three power uprate scenarios (1 percent, 3 percent, 10 percent) enumerated above. NRC estimates thirty percent more time to review applications for changes to a licensing basis under the new § 50.46a rule than to review applications solely for power uprates, due to a larger work load associated with reviewing the risk-informing and PRA information. The NRC review burden calculations are presented in Exhibit 9 below. An estimated average labor rate of $99 per hour was assigned for NRC staff time.

Exhibit 9
NRC REVIEW BURDEN FOR § 50.46a APPLICATIONS
(2008$)

Power Uprate Type	Review Burden	Impacts
Measurement Uncertainty Recapture (1%)	1,248 hours	$123,552
Stretch (3%)	2,340 hours	$231,660
Extended Power (10%)	5,070 hours	$501,930

Source: U.S. Nuclear Regulatory Commission, *SECY-04-0104: Status Report on Power Uprates*. June 24, 2004, and NRC calculations.

(b) Should the NRC decide to endorse a proposal for changes to the licensing basis, NRC must thoroughly document the decision and rationale for approval. The NRC has estimated this process will take 200 person-hours per application. Using an average NRC labor rate of $99 per hour, the cost to NRC is estimated to be $19,800 per license approved. NRC assumes this work burden will be accomplished in four month's time.

In 2001 and 2002 uprate requests increased significantly, NRC approved 22 power uprate requests in 2001 and 18 requests in 2002.[14] NRC staff have indicated that, apart from review of the ECCS re-evaluation and risk-based change submissions, the power uprates resulting from this rule change will not require extensive NRC review.[15] Therefore, in terms of Scenarios 1 and 2, it is reasonable to assume that NRC reviews will be completed within a similar time period. With regard to Scenario 3, NRC assumes a longer review time since 10 percent power uprates are considered "extended power" and therefore require more time to review.

This analysis assumes that these review costs will accrue to the NRC in 2010, 2011, and 2012. Exhibit 10 presents the annual costs associated with license amendment reviews under the three scenarios outlined above.

[14] U.S. Nuclear Regulatory Commission. "Fact Sheet: Power Uprates for Nuclear Plants." Washington, D.C. March 2004.

[15] Based on a phone conversation conducted with NRC staff July 30, 2004.

Exhibit 10
TOTAL ANNUAL NRC REVIEW BURDEN FOR § 50.46a UPRATE APPLICATIONS (2008$)

Scenario	Years	Number of Current Licensing Basis Requests	Review Burden	Licensing Process
1	2010-2012	6	$741,312	$237,600
2	2010-2012	5.33	$1,389,960	$237,600
3	2010-2012	4.67	$2,342,340	$184,800

(c) NRC is planning to develop two regulatory guides for this rule. This analysis assumes that 2,000 hours of NRC staff time and 4,000 hours of NRC contractor time will be required.[16] At an average labor rate of $99 per hour for NRC staff and $238 per hour for NRC contractors, the cost for the regulatory guide(s) would be $1,150,000, which would be incurred in 2010-2011.

(d) NRC must undertake the responsibility of reviewing risk reassessments from industry. NRC estimates that each risk reassessment review takes 200 person-hours of staff time. Using an NRC labor rate of $99 per hour, the NRC burden for reviewing each risk reassessment is $19,800 (i.e., 200 person-hours x $99 per hour). NRC anticipates reviewing licensee risk reassessments approximately every 3 years. For the purposes of this regulatory analysis, these recurring costs will accrue until the year 2052, the last year reviews will be necessary before the expiration of the last PWR license in 2054.

(e) NRC has directed the staff to conduct a rigorous re-estimation of LOCA frequency distributions every 10 years and review for new types of failures every 5 years. Staff is to conduct a practical reconciliation of LOCA frequency distributions by the (1) expert use of service-data, (2) probabilistic fracture mechanics (PFM), and (3) expert elicitation to converge the results. Research will be carried out to determine the accuracy of the previous frequency estimates and to determine if a new TBS should be set. This effort will be repeated every ten years. The NRC estimates this process will require 6,000 person-hours of NRC staff time and 12,000 person-hours of NRC contractor support time.[17] Using the

[16] The Probabilistic Safety Assessment Branch of the Division of Systems Safety & Analysis estimated, in August 2004, required resources of 600 staff hours to revise existing regulatory documents pertaining to crediting containment accident pressure in determining net positive suction head of ECCS and containment heat removal pumps. The original burden estimated for this regulatory analysis has been doubled to account for the new applicability requirement § 50.46a(c)(1)(i).

[17] NRC issued a three-year, $2.3 million, sole-source contract RS-RES-02-074 to Battelle Memorial Institute Columbus Operations to provide "Technical Development of Loss-of-Coolant Frequency Distributions," including PFM code, estimated LOCA frequency distributions, and management of expert elicitation process. This contract was preceded by a four-year contract NRC-04-98-039 for approximately $600K which ran from 1998-2002.

average labor rates of $99 per hour for NRC staff and $238 per hour for its contractors, the costs for each ten-year review are estimated to be $3,450,000 in 2008 dollars.

(f) NRC also will incur implementation costs associated with the review and approval of the EDG start-time relaxation requests. Activities involved in processing EDG applications under § 50.46a include review of the ECCS re-analyses; proposed plant modifications and their anticipated effects on SSC's, safety margins, and defense-in-depth measures; licensee plans for monitoring plant operations and equipment; changes in risk estimates (CDF, LRF, and LERF); and the scientific validity of the PRA performed by the licensee which encompasses the proposed plant changes. The NRC estimates that 2,000 person-hours of NRC staff time and 1,000 person-hours of contractor time will be required to perform each review. Using an estimated average labor rate of $99 per hour for NRC staff time and $238 per hour for NRC contractor support time, the total cost for each NRC review is anticipated to be $436,000 [(2,000 person-hours x $99 per hour) + (1,000 person-hours x $238 per hour)]. Since the EDG package will be submitted together with the power uprate application, NRC will not need to review the ECCS re-analyses, which NRC estimates to be about 25 percent of the total review burden, thus avoiding $109,000 (i.e., .25 x $308,000), for a net cost of 2,400 hours and $327,000, as summarized in Exhibit 11 below.

Exhibit 11
TOTAL ANNUAL NRC REVIEW BURDEN FOR PIGGY-BACKED EDG START TIME RELAXATION APPLICATIONS (2008$)

Scenario	Years	Number of Requests	Costs to NRC
1	2010 - 2012	6	$2,703,312
2	2010 - 2012	5.33	$3,351,960
3	2010 - 2012	4.67	$3,868,340

(g) NRC will need to evaluate applicability evaluations in accordance with § 50.46a(c)(1). NRC estimates that this burden will be proportional to the burden on licensees to meet the requirements of § 50.46a(c)(1). For the purposes of this regulatory analysis, it is assumed that NRC's burden is a 1:2 ratio to licensee burden (i.e. 1 hour of NRC effort for every 2 hours of licensee effort), based on other reciprocal burdens of this analysis. Accordingly, it is estimated that evaluating an applicability evaluation will require 750 hours of NRC staff time, based on a licensee burden of 1,500 person hours to prepare an applicability evaluation. Using an estimated average labor rate of $99 per hour, each applicability evaluation is anticipated to be $74,250.

(h) The new rule requires NRC to review any new codes, and it is possible that licensees will choose to perform an ECCS re-evaluation with a new code that has not been previously approved. NRC estimates reviewing a new code will require one staff-year of time. At an estimated average labor rate of $99 per hour, each review is anticipated to be $205,920. For the purposes of this regulatory analysis, it is assumed that two PWR fuel vendors, Westinghouse and Areva, will choose to perform an ECCS evaluation with a new code.

(i) The cost associated with analyzing the proposed changes also will be incorporated into this analysis. The analysis is assumed to have taken the time of two full-time employees at an estimated annual salary of $158,000, for a total cost of $316,000 (i.e., 2 x $158,000).

Exhibits 12 and 13 display the net present value, discounted at 3 and 7 percent respectively, of the total NRC impacts for all activities required to implement the new rule and review industry requests for changes to licensing basis given the three scenarios. The Review Submissions, Process License Amendments, and Review of PRA Updates lines of these exhibits reflect the total net present value of the costs associated with both the uprate and EDG applications.

Exhibit 12
NPV SUMMARY OF IMPACTS TO NRC @ 3% Discount Rate
(2008$)

Activity	Scenario 1	Scenario 2	Scenario 3
Prepare Reg. Guide(s)	$1,116,505	$1,116,505	$1,116,505
Review Submissions	$7,207,672	$8,937,121	$10,313,913
Process License Amendments	$633,498	$633,498	$492,721
Applicability Evaluation	$1,187,809	$1,187,809	$923,851
ECCS for New Code	$376,892	$376,892	$376,892
Review PRA Updates	$5,090,737	$5,090.737	$3,959,462
Research LOCA Frequencies	$6,179,900	$6,179,900	$6,179,900
Cost of Analysis	$316,000	$316,000	$316,000
Total	***$22,109,013***	***$23,838,463***	***$23,679,245***

Exhibit 13
NPV SUMMARY OF IMPACTS TO NRC @ 7% Discount Rate
(2008$)

Activity	Scenario 1	Scenario 2	Scenario 3
Prepare Reg. Guide(s)	$1,074,766	$1,074,766	$1,074,766
Review Submissions	$6,196,476	$7,683,293	$8,866,929
Process License Amendments	$544,622	$544,622	$423,595
Applicability Evaluation	$1,021,166	$1,021,166	$794,240
ECCS for New Code	$336,184	$336,184	$336,184
Review PRA Updates	$2,597,821	$2,597,821	$2,020,528
Research LOCA Frequencies	$3,137,180	$3,137,180	$3,137,180
Cost of Analysis	$316,000	$316,000	$316,000
Total	***$15,224,216***	***$16,711,033***	***$16,969,422***

3.4 Analysis of the Benefits

This section analyzes the different quantifiable benefits associated with the rule and estimates the present value of these benefits using 3 and 7 percent discount rates. Benefits are calculated separately for the three uprate scenarios discussed above and the corresponding increased generation over a "business-as-usual" baseline.

- Section 3.4.1 analyzes *Power Uprate Benefits*. Because electricity generated from nuclear units is cheaper than electricity generated from fossil fuels, increased nuclear generation due to uprates can lead to significant monetary benefits. *Power Uprate Benefits* are valued on the assumption that this increased nuclear generation would displace some of the more expensive generation capacity from other sources at the margin. Because nuclear generation costs less than fossil fuel generation on a per-unit basis, significant cost savings for the industry and society can result. This valuation method is defined as the *Generation Cost Savings* method in this study.

- Section 3.4.2 estimates the value of *EDG Benefits* by assessing how relaxed requirements for EDGs can lead to cost savings, not just from reduced labor cost and materials needed for maintenance tear downs, but also from the replacement power saved due to shortened outages.

The following sections provide details on the methods, data, and assumptions used to quantify these benefits associated with the rule change.[18] Summary tables providing the discounted benefits under the different scenarios are presented at the end of Section 3.4.

3.4.1 Power Uprate Benefits

Increased generation from existing PWR units can lead to significant quantifiable benefits. Because nuclear generation is cheaper than the other primary generating type -- fossil fuel -- increased nuclear generation from uprates can lead to significant monetary benefits.

NRC's method of valuing increased nuclear generation is to compare its cost to the more expensive generation costs from other sources, assuming that the former displace the latter and lead to *Generation Cost Savings*. On a per-unit basis, nuclear generation costs less than most other types of fossil generation, especially oil and gas generation. Oil and gas units have the highest variable cost of generation due to their high fuel cost. Because they have the highest cost, NRC assumed that, *at the margin*, the increased generation from nuclear units would replace the most expensive oil and gas units and lead to significant cost savings for the industry and society.

[18] In addition to these quantified benefits, industry representatives mentioned other potential benefits expected as a consequence of this proposed rulemaking (i.e., optimization of containment spray setpoints, fuel management improvements; elimination of potentially required actions for postulated sump blockage issues; changes to required number of accumulators, sequencing of equipment, and valve stroke times; among others).

The benefits depend not only on the cost and performance characteristics of nuclear power generation, but also on the characteristics of other sectors of the power industry, particularly oil and gas units (since the calculation depends on the ability of increased nuclear generation to displace oil and gas generation). Moreover, because of the extended time period for this analysis, the study uses projected data that take into account well-defined assumptions about the power industry. The data used for the projected cost and performance characteristics of the electricity generation industry are taken from the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic, linear programming model of the electric power sector used extensively by the Federal Energy Regulatory Commission (FERC) and the U.S. Environmental Protection Agency (EPA) to analyze policy and regulatory issues and to consider the costs and benefits of alternate proposals. Details on IPM's forecast capabilities and reasons why NRC chose to use IPM data for this analysis are discussed in Appendix A.

The data used for fossil and nuclear generation costs come from IPM projections for the Base Case scenario where results are reported for 2010, 2015, 2020, 2025, and 2032.[19] Specific years were chosen for reporting purposes in the exhibit below. This analysis assumes that the first year PWRs start benefitting from the LOCA rule is 2011, and therefore reports results for that year using 2010 data from IPM. For reasons discussed elsewhere in this report, NRC also assumed an annual phase-in rate such that the full impact of the rule is felt in 2013 (see Section 3.3.2 where the phase-in rate is discussed).

NRC's preferred approach to value the benefit of increased PWR generation is to assume that this increase will replace an equivalent amount of electricity generated by units that are most expensive to operate *at the margin*.[20] Comparison of generation cost data from IPM Base Case results indicate that, in terms of fuel and non-fuel variable operation and maintenance (VOM) costs, the most expensive units at the margin are the existing oil and gas units. In this method, NRC considered only the fuel and non-fuel VOM costs of competing sources of electricity to determine which units are more expensive than nuclear units, because these two cost components are functions of the generation level. Exhibit 14 below provides the projected costs for these types of units.

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[19] For details about the assumptions used in IPM Base Case scenario, see Appendix A.

[20] NRC employed this method in the Regulatory Analysis for the Revision of Appendix K of 10 CFR Part 50 (1999).

Exhibit 14
GENERATION COST SAVINGS ASSUMPTIONS
(2008$/MWh)

Assumptions	**2010**	**2015**	**2020**	**2025**	**2032**
Coal Generation Cost	21.62	20.99	20.56	20.42	23.19
Oil/Gas Generation Cost	53.93	49.46	47.35	48.31	48.92
Nuclear Generation Cost	8.55	9.04	9.43	9.53	9.38
Cost Savings per MWh[1]	**45.38**	**40.42**	**37.92**	**38.78**	**39.54**

[1] Cost Savings are calculated as the difference between the generation costs of oil/gas units and nuclear units. Generation cost data for the coal units are presented for illustrative purposes only.
Sources: IPM Base Case results and NRC calculations.

According to IPM's Base Case forecasts, generation cost from oil/gas units is expected to hover around $47-$53/MWh between 2010 and 2032. Generation cost from nuclear units in the same time period is projected to be less than $10/MWh. The difference in the per MWh generation cost is thus $45.38/MWh in 2010, which indicates the per-unit cost saving if a MWh of oil and gas generation is replaced by additional nuclear generation. Similar calculations were performed to obtain the per-unit generation cost savings for the other years in the exhibit above.

Given the increased generation expected from PWRs because of this rule, NRC then calculated the total generation cost savings by multiplying this per-unit cost savings times the incremental generation expected from PWRs for each of the three scenarios. The analysis assumes that one third of participating PWRs will experience power uprates in 2012, two thirds in 2013, and all participating PWRs for each scenario will experience power uprates through the remaining life of their license, until the expiration of the last license in 2054.

3.4.2 Relaxation of EDG Start Time Benefits

NRC believes that the rule change will allow PWRs to eliminate fast-starts of EDGs. This will yield two categories of benefits to the plants.

First, PWRs will benefit from the reduced cost and time needed for EDG maintenance tear downs. Specifically, reactors will experience cost savings related to materials and labor used to conduct tear downs. For each uprate scenario, NRC assumed 80 percent of the plants will save $213,396 per year and the remaining 20 percent will save $328,111 per year in reduced costs for maintenance tear downs (in 2008$). The $213,396 per-year figure is based on a savings of 26% in baseline tear down costs of $500,000 (in 2000$) per EDG every 18 months; the latter figures were provided by WOG in 2000, and NRC adjusted and inflated the numbers to reflect a per-year value, as plants typically have 2 EDGs. The $328,111 figure also originates with WOG estimates that, if EDG tear downs had been outsourced, the reduction in scope of the tear down could result in $200,000 (in 2000$) savings per EDG by allowing the work to be performed in-house. NRC adjusted the $200,000 savings figure to reflect 2 EDGs per plant and an annual basis. Based on input from the vendor community and NRC staff, and to be conservative, the regulatory analysis assumes most PWRs will be able to attain the smaller savings amount, as opposed to the larger amount.[21]

Second, EDG tear downs typically occur during scheduled reactor outages necessary for refueling and other maintenance. Such refueling outages occur, on average, every 18 months and last 35 days. This rule is expected to reduce the duration of such outages by reducing the duration of the tear downs. In 2000, the WOG stated that if the EDG tear down was done during a refueling outage and was on the critical path, the tear down scope reduction could reduce the critical path duration by 3.5 days. To be conservative, NRC assumed, for each uprate scenario, only 10 percent of the plants experiencing EDG benefits will save 3.5 days of avoided replacement power costs (out of the average duration of 35 days) in addition to the savings above.

Since the replacement power cost savings in this section arise only during outages, NRC first determined the number of PWRs having such outages every year, based on their last scheduled outage data[22] and assuming these outages occur every 18 months for each plant. Then, because the number of units affected under the three uprate scenarios are different, NRC estimated the corresponding number of units that can save on replacement power costs due to reduced outage duration, assuming all PWRs are equally likely to benefit. For example, since 75 percent of the participating plants are affected under uprate scenario 3, and since only 10 percent of these units may save on replacement power, NRC assumed 7.5 percent of the participating operating units save on replacement power (75% x 10% = 7.5%). Moreover, since 3.5 days of savings out of a 35-day outage duration translate to a 10 percent savings for these plants, the overall savings is estimated to be 0.75 percent of the total replacement power needs for participating PWRs (10% x 7.5% = 0.75%).

To estimate how much replacement power is needed during these scheduled outages every year, and consequently, how much money can be saved, NRC used the projected annual generation under the baseline and assumed an average outage duration of 35 days per outage per plant. However, since the number of operating plants decrease rapidly over time (once licenses expire), NRC weighted the total generation lost by the proportion of operating plants having scheduled outages for each year. Combining these calculations, NRC estimated the total MWh of replacement power that can be saved annually by relaxing EDG start times.

To estimate the value of the replacement power saved, NRC then multiplied the MWh of replacement power saved calculated above, by the difference between the wholesale price of electricity (in $/MWh) and the average variable cost of nuclear generation consisting of the fuel, and non-fuel VOM costs (in $/MWh). This difference represents the per MWh savings for a plant from not having to purchase replacement power during outages, and multiplying this per-

[21] It is possible that the BWRs also benefit from the reduced cost and time needed for EDG maintenance tear downs. However, the analysis presented above does not attempt to quantify the benefits to BWRs from this rule.

[22] Scheduled outage data were obtained from the NRC Daily Report Files, available at www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status.

unit savings by the MWh of replacement power saved gives the total cost savings due to a 3.5-day reduction in scheduled outages.

Finally, the total benefit is calculated by summing up the cost savings from reduced tear down labor and materials and the cost savings from reduced replacement power needs for each scenario for each year. Results are presented using 3 and 7 percent discount rates.

According to NRC staff, over the past 10 years, the NRC has become increasingly open to relaxing the testing requirements for fast-starts. This has included changing from fast-start tests on a monthly basis to monthly tests using a slow-start procedure and one fully loaded test every six months that mimics an emergency situation calling for a fast-start. Additionally, the NRC is allowing pre-lube and pre-warm systems during all surveillance start tests, and has relaxed the 3-day servicing to be conducted while the plant is on-line. On-line servicing has significantly reduced the replacement power issue associated with major tear down events. Unfortunately, data were not available regarding the extent to which PWRs have been able to take advantage of these policies.

3.4.3 Results of Benefits Analyses

In sum, Exhibits 15, 16, and 17 below present benefit results for Scenarios 1, 2, and 3, respectively, using 3 and 7 percent discount rates.

Exhibit 15
PRESENT VALUE OF MONETIZED BENEFITS UNDER UPRATE SCENARIO 1[a]
(2008$ in Millions)

Discount Rates	Increased Nuclear Energy Benefits	Relaxation of EDG Benefits	Total
3 percent	899	136	1,035
7 percent	505	72	577

[a] Uprate Scenario 1 assumes a 1% uprate for 18 PWRs.
Totals may not add due to rounding.

Exhibit 16
PRESENT VALUE OF MONETIZED BENEFITS UNDER UPRATE SCENARIO 2[a]
(2008$ in Millions)

Discount Rates	Increased Nuclear Energy Benefits	Relaxation of EDG Benefits	Total
3 percent	2,697	136	2,832
7 percent	1,515	72	1,588

[a] Uprate Scenario 2 assumes a 3% uprate for 18 PWRs
Totals may not add due to rounding.

Exhibit 17
PRESENT VALUE OF MONETIZED BENEFITS UNDER UPRATE SCENARIO 3[a]
(2008$ in Millions)

Discount Rates	Increased Nuclear Energy Benefits	Relaxation of EDG Benefits	Total
3 percent	6,796	104	6,901
7 percent	3,811	56	3,866

[a] Uprate Scenario 3 assumes a 10% uprate for 14 (75% of) PWRs
Totals may not add due to rounding.

4. VALUE-IMPACT RESULTS

This section integrates the principal costs and benefits associated with the rulemaking to add provisions to 10 CFR Part 50.46 to enable licensees to use a risk-informed alternative maximum LOCA break size to support risk-informed changes in a reactor's design and operations.

4.1 Principal Benefits Assessed

The following benefits were quantified as part of this regulatory analysis:

Power Uprate Benefits. These benefits accrue from the increased nuclear generation facilitated by the rulemaking. Because nuclear power is cheaper to generate than power from non-nuclear sources, the rulemaking will result in cost savings.

Relaxed EDG Start-Time Benefits. These benefits result from savings in the cost of EDG tear downs as well as some additional savings due to reduced outages and replacement power needs resulting from less time required for EDG tear downs.

4.2 Principal Costs Assessed

The following costs were quantified as part of this regulatory analysis:

Industry Costs. The burden of these costs will fall on nuclear power licensees and may be further classified as:

- *Initial Licensing Costs*: These upfront costs include the emergency core cooling system re-analysis, engineering analysis, design of annual monitoring program, definition of change, license amendment, submission of license modification proposal, costs of local monitoring equipment, evaluation of leakage monitoring systems, modification of technical specifications, procedural modifications, and preparing applicability evaluations.

- *Capital Costs*: These are the costs of plant upgrades that will be necessary to achieve the projected uprate levels. *(**Note:** This analysis computed both a low-end and a high-end* *estimate of capital costs. Only the high-end values are displayed and utilized in the value-impact analysis).*

- *Recurring Monitoring/Licensing Costs:* These include an annual monitoring program and a recurring three-yearly probabilistic risk reassessment update.

NRC Costs. The burden of these costs initially would fall on the NRC and may be further classified as:

- *Initial Regulatory Costs:* These up-front costs include the NRC review of submissions, management of the license amendment process, the development of regulatory guides, the review of applicability evaluations, and the review of new codes .

- *Deferred/Recurring Regulatory Costs:* These include the cost of a recurring 10-year TBS review and a recurring three-yearly probabilistic risk reassessment review.

4.3 Key Assumptions

Scenarios Assessed. Three different scenarios reflecting potential industry responses to the rule-making were assessed as part of this analysis. These scenarios were described earlier in Section 3.3.3; a summary table is repeated here for ready reference.

Exhibit 18
SUMMARY OF POWER UPRATE AND EDG SCENARIOS
(BASED ON BASELINE OF 18 PARTICIPATING PWRS)

Scenario	Degree of Power Uprate	Degree of Participation
1	1%	25%
2	3%	25%
3	10%	20%

The regulatory analysis assumes that PWRs which apply for power uprates simultaneously apply for relaxed EDG start times. PWRs which do not apply for power uprates are assumed to not apply for relaxed EDG start times.

Energy Demand. An assumption inherent in this analysis is that the increased nuclear generation will be "absorbed" in the market. Under the three scenarios for this rule, the highest overall increase in PWR generation is 1.9 percent under Scenario 3, which, assuming PWRs comprise about two-thirds of all nuclear generation, and nuclear generation is approximately 20 percent of total generation, implies an overall increase of less than 1 percent of electricity generation due to this rule (20% x 66% x 1.9% = 0.002%). Given the Energy Information Agency's assumption of about a 1.1 percent annual growth rate in electricity demand in the reference case,[23] and that this added nuclear capacity is from current nuclear plants operating

[23] See Energy Information Agency, *Annual Energy Outlook 2008* - Table A8 - "Electricity Supply, Disposition, Prices, and Emissions".

more efficiently, coupled with the fact that nuclear plants generally have lower marginal cost of generation than fossil units, NRC expects this added generation to be absorbed fairly easily in the market without any significant price impact. In other words, the absorption assumption appears quite reasonable.

Base-Year for Present Value Estimates. All present value estimates are for the year 2008.

Base-Year for Real Dollar Values. All discounted costs and benefits are reported in 2008 dollars.

Inflation Indices. Cost estimates were updated to 2008 dollars using inflation indices obtained from the Bureau of Labor Statistics inflation calculator at http://data.bls.gov/cgi-bin/cpicalc.pl.

Discount Rates. NRC Guidelines Section 4.3.3 states that, based on OMB guidance, both 3% and 7% real discount rates are to be used in preparing regulatory analyses. Accordingly, real discount rates of 3 percent per-year and 7 percent per-year have been applied in this analysis.

4.4 Net Present Value Estimates of the Rule

Exhibits 19 and 20 display net present value estimates of the rule for 3 and 7 percent discount rates, as specified, for each of the three scenarios defined earlier. All values presented below are in millions of 2008 dollars, rounded to the nearest million. Values in parentheses represent costs.

Exhibit 19 presents the net present value in the year 2009 (in millions of 2008 dollars) of the rule at a 7 percent per-year discount rate.

Exhibit 19
Net Present Value in 2009 in millions of 2008$
Annual Discount Rate = 7%

Quantitative Attributes		Present Value Estimates (2008$)		
		Scenario 1	**Scenario 2**	**Scenario 3**
Power Uprating Benefits		$505	$1,515	$3,811
EDG Benefits		$72	$72	$56
Licensee Costs	Capital Costs	($57)	($171)	($797)
	Initial Licensing Costs	($59)	($59)	($46)
	Recurring Costs	($168)	($168)	($130)
NRC Costs	Initial Regulatory Costs	($9)	($11)	($12)
	Deferred/Recurring Regulatory Costs	($6)	($5)	($5)
Overall Net Present Value		$279	$1,173	$2,876

Note: Totals are subject to round-off error

Exhibit 20 presents the net present value in the year 2008 (in millions of 2008 dollars) of the rule at a 3 percent per year discount rate.

Exhibit 20

Net Present Value in 2009 in millions of 2008$
Annual Discount Rate = 3%

Quantitative Attributes		Present Value Estimates (2008$)		
		Scenario 1	**Scenario 2**	**Scenario 3**
Power Uprating Benefits		$899	$2,697	$6,796
EDG Benefits		$136	$136	$104
Licensee Costs	Capital Costs	($66)	($149)	($927)
	Initial Licensing Costs	($63)	($63)	($49)
	Recurring Costs	($315)	($315)	($245)
NRC Costs	Initial Regulatory Costs	($11)	($13)	($14)
	Deferred/Recurring Regulatory Costs	($11)	($11)	($10)
Overall Net Present Value		$568	$2,231	$5,656

Note: Totals are subject to round-off error

4.5 Significant Results in the Present Value Analysis

The principal results from the present value analysis are as follows:

- The net present value of the rule is positive, regardless of discount rate or scenario.
- The low-bound NPV (at a 7 percent discount rate and under scenario 1 assumptions) is estimated at $279 million.
- The high-bound NPV (at a percent 3 discount rate and under scenario 3 assumptions) is estimated at $5,656 million.
- For any given discount rate, NPV in Scenario 3 > NPV in Scenario 2 > NPV in Scenario 1. In other words, the economic value to society increases as more plants undertake greater uprates facilitated by the rule.
- Using a discount rate of 3 percent instead of a discount rate of 7 percent approximately doubles NPV estimates, for any given scenario.

5. DISAGGREGATION

In order to comply with the guidance provided in Section 4.3.2 (“Criteria for the Treatment of Individual Requirements”) of the Regulatory Analysis Guidelines, the NRC conducted a screening review to determine if any of the individual requirements (or set of integrated requirements) of the final rule are unnecessary to achieving the objectives of the rulemaking. The

NRC determined that the objectives of this rulemaking are to: (1) establish a risk-informed alternative set of emergency core cooling regulations; (2) that the alternative provides additional operational flexibility to licensees; and (3) any additional flexibility or operational condition "enabled" by the risk-informed provisions of this rule will nonetheless provide adequate protection to the public health and safety. Furthermore, the NRC concluded that each of the final rule's requirements is necessary to achieve one or more objectives of the rulemaking. The results of this determination are set forth in the following table.

Regulatory Goals for 10 CFR 50.46a	(1) Establish Risk-Informed Alternative Regulations	(2) Alternative Regulations Provide Additional Flexibility to Licensees	(3) Adequate Protection of Public Maintained Given Additional Operational Flexibility
Paragraph (a) Definitions	X	X	
Paragraph (b) Applicability	X	X	
Paragraph (c) Application			X
Paragraph (d) Requirements during operation			X
Paragraph (e) ECCS performance	X	X	X
Paragraph (f) Changes to facility, technical specifications, or procedures	X		X
Paragraph (g) Reporting			X
Paragraph (h) Documentation			X
Paragraph (m) Changes to TBS			X

Second, the NRC evaluated whether any of the rule's requirements masks the inclusion of individual requirements that are not cost-beneficial when considered separately. The NRC determined that there were no individual requirements to which a disproportionate share of the benefits would be attributed to, such that the aggregation of that requirement's benefits into a single overall rulemaking benefit would mask inclusion of other, unjustified (non-cost beneficial) requirements.

6. DECISION RATIONALE

Based on the available information, it is the NRC's judgment that the values described above substantially outweigh the identified impacts. However, because the rule is voluntary, NRC does not know how many or which licensees will seek to use it nor how those licensees will value the potential benefits of the rule.

7. REFERENCES

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Westinghouse Owners Group, "Comments on Cost and Benefit of NRC's Conceptual Rule Change for Redefining the Large Break Loss of Coolant Accident Design Basis Break Size in 10 CFR 50.46," WOG-04-470, September 16, 2004.

APPENDIX A
BENEFITS VALUATION METHODS

This Appendix provides further details on the methodology used to determine the baseline power generation for all 69 PWRs and the steps involved in calculating the increased generation due to the three scenarios. It also provides further details on the Integrated Planning Model (IPM) used for analyzing the cost and performance characteristics of the power sector, including projected emissions.

A.1 Convert Uprates into Increased Base Power Generation

The first step in quantifying the benefits of uprates is to estimate the generation increases as a result of expected uprates. To do that, this study first defines a baseline generation from all PWRs based on historical data and then Energy Information Administration's (EIA) projections for capacity factors. Next, to convert the uprate scenarios to increased generation, an "Overall Increase" parameter is calculated for the different scenarios. Since all uprate scenarios provide a "Degree of Participation" less than 100 percent, and identifying which PWRs would actually benefit under each scenario is beyond the scope of this study, NRC calculated an "Overall Increase" parameter that combined the Degrees of Uprate and Participation into one composite number as a convenience for the analysis. (See Exhibit A-1). That is, under Scenario 3, instead of estimating the impact of 20 percent of the 69 PWRs increasing their generation by 10 percent, this study estimated the benefit of 69 PWRs increasing their generation by 5 percent (i.e., 20% x 10% = 5.0%). This assumes that participating PWRs are equally likely to apply for and benefit from the marginal uprates.

Exhibit A-1
Uprate Scenarios

Scenarios	Degree of Uprate	Degree of Participation	Overall Increase
1	1%	25%	.25%
2	3%	25%	.75%
3	10%	20%	2%

A.2 Determination of Baseline Generation

The baseline generation for all PWRs is calculated using the following steps:

Using actual summer 2002 capacity and the corresponding capacity factors for all 69 PWRs from EIA, this study first calculated their actual generation in 2002.

2. To calculate the baseline generation beyond 2002, NRC assumed all PWR units will apply for and receive a 20-year license extension (some plants already have received license

extensions). This yielded a total time period for the analysis that extended up to 2054, when the last PWR unit (Watts Bar 1) reaches the end of its extended license period.

3. Also, using projections from EIA's *Annual Energy Outlook* (AEO) 2008, NRC assumed an average capacity factor of 90 percent between 2002 and 2010 and 91 percent for the period after 2010 until the end of a plant's license. Note that EIA provided capacity factor projections until 2025, and NRC used the same capacity factors for the period beyond that due to the lack of any other data sources.

4. For those plants that already have implemented an uprate (58 PWRs), NRC incorporated the increased capacity in estimating the baseline generation. However, for those that plan to apply for an uprate but have not done so yet, NRC excluded the planned uprates from the baseline. There are two such units that have pending uprate applications with NRC.[1]

Exhibit A-2 below presents the baseline generation for all PWRs for 2002 and NRC's projections based on the discussion above.[2] For brevity, results are presented for selected years only.

Exhibit A-2
PWR GENERATION IN BASELINE AND UNDER UPRATING SCENARIOS

Assumption	**2002**	**2008**	**2012**	**2020**	**2040**	**2050**
Avg. Capacity Factor (%)	90	90	91	91	91	91
Generation ('000 GWh)						
Baseline	527	527	532	521	297	18
Scenario 1	--	--	533	527	300	18.6
Scenario 2	--	--	536	535	305	18.9
Scenario 3	--	--	545	560	319	19.8

Sources: EIA Survey Form 906 (for 2002 generation data), AEO 2004 projections, and NRC calculations.

The increased generation in the baseline from 2012 is due to the increased capacity factor assumption (91 percent versus 90 percent), based on EIA's projections. The significant drop in PWR generation for 2040 is driven by units shutting down as their licenses expire. In fact, 2050 generation shown in the Exhibit above is from two out of the 69 units - Comanche Peak 2 and Watts Bar 1, with all the others having reached the end of their license renewal periods.

[1] See NRC website www.nrc.gov/reactors/operating/licensing/power-uprates/approved-applications.html for data on uprates.

[2] To verify the baseline calculations for 2002, NRC cross-checked the total generation estimated in Exhibit A-2 with other industry data. Given that the nuclear industry generates about 20 percent of total electricity and PWRs make up about two-thirds of all nuclear units (the other one-third being BWRs), the expected generation from PWRs is about 13 percent of total annual generation (20% x 67% = 13%). Since EIA estimated total electricity generation in 2002 was about 3,831 million MWh, the baseline estimate of 520 million MWh from PWRs in 2002 equates to approximately 13.6 percent of the total generation.

A.3 Increased Generation Due to the Three Uprating Scenarios

The next step in this analysis was to calculate the increased generation over the baseline expected from the three uprate scenarios. Using the same capacity factor assumptions outlined above for the lifetime of the plants, NRC calculated the incremental generation from the PWRs under the three uprate scenarios defined above. Exhibit A-2 above summarizes these results. Again, for brevity, results are presented for selected years only.

Similar temporal patterns are observed in the generation increases due to uprates. Moreover, generation increases across uprate scenarios are directly proportional to the overall increase assumptions shown in Exhibit A-1 above. Thus Scenario 1 produces the smallest incremental generation and Scenario 3 the largest, because of the similar patterns in the overall increase parameter above.

A.4 Integrated Planning Model

Most of the benefit calculations in this regulatory analysis are driven by the characteristics of the electric power industry in general, and the nuclear industry in particular. The data used for the projected cost and performance characteristics of the electricity generation industry are taken from the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic, linear programming model of the electric power sector used extensively by the Federal Energy Regulatory Commission (FERC) and the U.S. Environmental Protection Agency (EPA) to analyze policy and regulatory issues and to consider the costs and benefits of alternate proposals.[3] IPM can provide forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting various energy demand and environmental (both single- and multi-pollutant), transmission, dispatch, and reliability constraints. IPM is one of the best known simulation models used to project the behavior of the power industry and has been extensively peer-reviewed. NRC used results from this model in this regulatory analysis because they are easy to understand, readily available in the public domain, and perhaps more importantly, used extensively by EPA to estimate impacts for potential regulations that would have effects similar to the ones analyzed in this study (i.e., reduced emissions from fossil-fueled power plants).

Much of the IPM data used in this analysis have been taken from results for the EPA "Base Case assumptions." The Base Case assumes the current state-of-the-world is true going forward and projects industry characteristics and behavior until 2020.[4] Because Base Case projections are used only until 2020 and because the time period in this analysis extends until 2054, NRC assumed that IPM projections for 2020 would be constant until 2054 when the last of the PWRs

[3] More information on IPM is available at EPA's website at www.epa.gov/airmarket/epa-ipm/.

[4] The full set of constraints used in the Base Case simulation and detailed results can be accessed at the EPA website www.epa.gov/airmarkets/epa-ipm/results2003.html. IPM also projects for 2026, but because this is the last year in the model's time horizon, IPM recommends not using those data for significant uncertainty.

shuts down.[5] This is similar to the assumption for the EIA projections that also end in the same time horizon. Given the large uncertainties expected in any projections beyond 2020, this is the least speculative approach when dealing with an extended analysis period.

[5] This is the recommended approach when using IPM data, because 2026, being the last year in IPM's horizon, may produce estimates that are less reliable than the other years.