ATTACHMENTS

Attachment J

Letter from David Brook, North Carolina State Historic Preservation Office
(signed by Renee Gledhill-Early)
to
Jennifer R. Huff, Duke Energy
dated January 31, 2000.

North Carolina Department of Cultural Resources
State Historic Preservation Office
David L. S. Brook, Administrator

FEB 4 2000
Duke Power Company
Group Environmental,
Health & Safety Dept.

James B. Hunt Jr., Governor
Betty Ray McCain, Secretary

Division of Archives and History
Jeffrey J. Crow, Director

January 31, 2000

Jennifer R. Huff
Duke Power
PO Box 1006
Charlotte, NC 28201-1006

Re: McGuire Nuclear Station License Extension

Dear Ms. Huff:

Thank you for your January 26, 2000 letter. We concur that the extension of the operating license for McGuire Nuclear Station is not an undertaking that is likely to affect historic properties. No further compliance with Section 106 is , therefore, required.

The above comments are made pursuant to Section 106 of the National Historic Preservation Act and the Advisory Council on Historic Preservation's Regulations for Compliance with Section 106 codified at 36 CFR Part 800.

Thank you for your cooperation and consideration. If you have questions concerning the above comment, please contact Renee Gledhill-Earley, environmental review coordinator, at 919/733-4763.

Sincerely,

Renee Gledhill-Earley

for David Brook
Deputy State Historic Preservation Officer

DB:scb

Attachment K

McGuire Nuclear Station
Severe Accident Mitigation Alternatives (SAMAs) Analysis
May 2001
Final Report

McGUIRE NUCLEAR STATION

Severe Accident Mitigation Alternatives (SAMAs) Analysis

May 2001

Final Report

TABLE OF CONTENTS

1.0 Introduction and Background

This report presents the "consideration of alternatives to mitigate severe accidents" for McGuire Nuclear Station, in compliance with environmental review requirements in 10CFR51.53(c)(3)(ii)(L). For this analysis, SAMAs (severe accident mitigation alternatives) will include a review of potential design alternatives (SAMDAs - severe accident mitigation design alternatives) along with any procedural, non-hardware, alternatives. The objective of the SAMAs review is to facilitate the consideration of cost-beneficial plant modifications that could reduce the risk of severe accidents for plant operation during the license renewal period. This is achieved by identifying potential plant enhancements that could provide substantial severe accident benefit and then assessing the need and viability of those enhancements from a cost-benefit standpoint. The severe accident benefit is assessed in terms of the total averted risk (including averted public exposure, averted onsite cleanup cost, averted onsite exposure risk, and averted offsite property damage) by the proposed alternative. The cost-benefit analysis is performed using 2000 dollars for the cost of alternatives and the present worth of averted costs. Supplement 1 to Regulatory Guide 4.2 [Reference 1.1] is used as guidance for the McGuire SAMAs analysis. This Regulatory Guide states:

"The results of the following analytical steps should be presented in the Environmental Report, and the methodology or analytical process should be described.

1. Based on the plant-specific risk study and supplementary analyses, identify and characterize the leading contributors to core damage frequency and offsite risk (i.e., population dose).
2. From the IPEEE and any other external event analyses, provide estimates of the incremental contribution to dose consequence risk identified from the IPE.
3. Identify practical physical plant modifications and plant procedural and administrative changes that can reduce severe accident dose consequence risk. For each modification or change, estimate the approximate reduction in risk.
4. Estimate the value of the reduction in risk. Value is usually calculated for public health, occupational health, offsite property, and onsite property.
5. Estimate the approximate cost of each modification and procedural and administrative change found to reduce consequence risk of severe accidents. Potential SAMAs that are not expected to be cost beneficial may be screened out based on a bounding analysis.
6. Perform a more detailed value-impact analysis for remaining SAMAs to identify any plant modifications and procedural changes that may be cost effective.
7. List plant modifications and procedural changes (if any) that have or will be implemented to reduce the severe accident dose consequence risk."

As background, Duke Energy (Duke) has been actively involved since before 1984 in the development of plant-specific probabilistic risk assessments (PRA), individual plant examinations (IPE/IPEEE), and component/system reliability studies to evaluate severe accidents at McGuire (see Section 2.0). These studies have led to changes in the plant configuration and enhancements in plant procedures to reduce vulnerability of the plant to certain accident sequences.

This report presents an assessment of additional alternatives that could be implemented based on the current McGuire risk profile. Section 3.0 discusses the methodology used by Duke to perform this assessment. The methodology selected for this analysis involves reviewing the current risk profile using the McGuire PRA Revision 2 results and identifying: (a) the severe accident sequences dominating the core damage frequency (CDF), and (b) the severe accident sequences dominating the person-rem risk. In Sections 4.0 and 5.0, the list of potential alternatives are screened using a high-level cost-benefit comparison. A more detailed cost-benefit analysis is performed on those candidates that survive the initial screening analysis.

In addition, Duke has implemented two ongoing programs—the Maintenance Rule Program and the Severe Accident Management Guideline Program to manage severe accident risk. These are described in Section 2.2.

2.0 Risk Reduction Measures Previously Considered

The following paragraphs provide brief descriptions of previous studies that have been performed by Duke to identify potential plant enhancements at McGuire. The McGuire PRA study, which was published in 1984, was performed prior to the existence of regulatory guidance. The IPE and IPEEE studies were performed in response to Generic Letter 88-20, as supplemented. The McGuire switchyard reliability study was performed at Duke's initiative to assess the reliability of the off-site power system and any potential plant enhancements that needed to be implemented to further reduce the risk associated with the failure of this system.

2.1 Past Studies

<u>McGuire PRA</u>

In 1984, Duke completed an initial study documenting a full-scope Level 3 PRA for McGuire Nuclear Station. The McGuire PRA study identified the major failure combinations that can lead to core damage, and Duke has taken initiative in making plant enhancements as a result of the study. Table 2-1 identifies the plant enhancements implemented as part of the initial study.

<u>McGuire IPE</u>

In 1988, Duke initiated a large-scale review and update of the initial study. The major objectives of the review and update were to incorporate plant changes made since the time of the original study, improve on assumptions made in the original study, make use of plant experience/data from the 1980s, and utilize improvements in PRA methodology and up-to-date techniques.

On November 23, 1988, the NRC issued Generic Letter 88-20 [Reference 2.1], which requested that licensees conduct an Individual Plant Examination (IPE) in order to identify potential severe accident vulnerabilities at their plants. The McGuire response to GL 88-20 was provided by letter dated November 4, 1991 [Reference 2.2]. McGuire's response included the updated McGuire PRA (Revision 1) study. The McGuire PRA Revision 1 study and the IPE process resulted in a comprehensive, systematic examination of McGuire with regard to potential severe accidents. The McGuire study was a full-scope, Level 3 PRA with analysis of both the internal and external events. This examination identified the most likely severe accident sequences, both internally and externally induced, with quantitative perspectives on their likelihood and fission product release potential. The results of the study have prompted changes in equipment, plant configuration and enhancements in plant procedures to reduce vulnerability of the plant to some accident sequences of concern which are identified in Table 2-1.

By letter dated June 30, 1994 [Reference 2.3], the NRC provided an evaluation of the internal events portion of the above McGuire IPE submittal. The conclusion of the NRC letter [page 15] states:

> The staff finds the licensee's IPE submittal for internal events including internal flooding essentially complete, with the level of detail consistent with the information requested in NUREG-1335. Based on the review of the submittal and the associated supporting information, the staff finds reasonable the licensee's IPE conclusion that no fundamental weakness or severe accident vulnerabilities exist at McGuire. The staff notes:
>
> (1) Duke Power Company personnel were considerably involved in the development and application of Probabilistic Safety Assessment techniques to the McGuire facility, and that the associated walkdowns and documentation reviews constituted a viable process for confirming that the IPE represents the as-built, as-operated plant.
> (2) The front-end IPE analysis appears complete, with the level of detail consistent with the information requested in NUREG-1335. In addition, the employed analytical techniques reflect commonly accepted practices and are capable of identifying potential core damage vulnerabilities.
> (3) The back-end analysis addressed the most important severe accident phenomena normally associated with ice condenser containments, for instance, direct containment heating (DCH), induced steam generator tube rupture (ISGTR), and hydrogen combustion. No obvious or significant problems or errors were identified.
> (4) The human reliability analysis (HRA) allowed the licensee to develop a quantitative understanding of the contribution of human errors to core damage frequency (CDF) and containment failure probabilities.
> (5) Based on the licensee's IPE process used to search for decay heat removal (DHR) vulnerabilities, and review of McGuire plant-specific features, the staff finds the DHR evaluation consistent with the intent of the USI A-45 (Decay Heat Removal Reliability)
> (6) The licensee's response to Containment Performance Improvement (CPI) Program recommendations, which include searching for vulnerabilities associated with containment performance during severe accidents, is reasonable and consistent with the intent of Generic Letter 88-20, Supplement 3.
>
> In addition, and consistent with the intent of Generic Letter 88-20, the staff believes the licensee's peer review process provided assurance that the IPE analytical techniques had been correctly applied and that documentation is accurate.
>
> Based on the above findings, the staff concludes that the licensee demonstrated an overall appreciation of severe accidents, has an understanding of the most likely severe accident sequences that could occur at the McGuire facility, has gained a

> quantitative understanding of core damage and fission product release, responded to safety improvement opportunities. The staff, therefore, finds the McGuire IPE process acceptable in meeting the intent of Generic Letter 88-20. The staff also notes that the licensee's intent to continue use of the IPE as a "living" document, will enhance plant safety and provides additional assurance that any potential unrecognized vulnerabilities would be identified and evaluated during the lifetime of the plant.

McGuire IPEEE

In response to Generic Letter 88-20, Supplement 4, Duke completed an Individual Plant Examination of External Events (IPEEE) for severe accidents. This IPEEE was submitted to the NRC by letter dated June 1, 1994 [Reference 2.4]. The report contains a summary of the methods, results and conclusions of the McGuire IPEEE program. The IPEEE process and supporting McGuire PRA include a comprehensive, systematic examination of severe accident potential resulting from external initiating events. The McGuire IPEEE has identified the severe accident sequences of significance resulting from the external initiating events with quantitative perspectives on their likelihood. Significantly, no fundamental plant weaknesses or vulnerabilities with regard to external events were identified during the IPEEE examination. However, enhancements to plant hardware and procedural guidelines have been recommended. Table 2-1 identifies the enhancements implemented as a result of the IPEEE analysis.

By letter dated February 16, 1999 [Reference 2.5], the NRC provided an evaluation of the above McGuire IPEEE submittal. The conclusion of the NRC letter [page 6] states:

> The staff finds the licensee's IPEEE submittal is complete with regard to the information requested by Supplement 4 to GL 88-20 (and associated guidance in NUREG-1407), and the IPEEE results are reasonable given the McGuire design, operation, and history. Therefore, the staff concludes that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the McGuire IPEEE has met the intent of Supplement 4 to GL 88-20.

McGuire Switchyard Study

In 2000, Duke completed an initial study for the McGuire offsite power system confirming the high reliability of the switchyard design and configuration. The results of the study identify human error, equipment associated with runback of a unit generator, and equipment supporting unit bus line power paths as the dominant contributors to system unavailability. These insights are expected to enhance offsite power system configuration and control.

2.2 Ongoing Initiatives

The following two programs are ongoing initiatives at Duke to further reduce the risk associated with the plant operation of McGuire. The first program discussed is the McGuire ORAM-Sentinel, which was implemented at McGuire in response to 10CFR 50.65. The second program, the Severe Accident Management Guidelines Program, is in response to a regulatory requirement for closure of the severe accident regulatory issue (SECY 88-147, Generic Letter 88-20).

McGuire Maintenance Rule (ORAM-SENTINEL) Program

In 1996, Duke implemented the McGuire Maintenance Rule Program as an administrative program to ensure that structures, systems, and components important to safety are available and capable of reliably performing their intended safety function. The program requires the monitoring of availability and reliability of Maintenance Rule SSCs against predetermined performance criteria. The performance criteria are set commensurate with safety and benchmarked against the McGuire PRA to ensure that any potential impact on overall plant core damage frequency is minimized and acceptable.

A configuration risk management program is also used to manage the increase in risk that may result from maintenance activities. In conjunction with governing administrative procedures, the ORAM-Sentinel computer software program is used to evaluate the change in core damage frequency from maintenance activities as well as to evaluate their impact on the level of "defense-in-depth" for key plant safety functions. All planned maintenance activities are evaluated for their potential impact on plant risk prior to execution, and then schedules are adjusted to optimized to achieve the lowest possible risk configurations. For shutdown conditions, an administrative process is used in a similar manner to assess and manage outage risk.

McGuire Severe Accident Management Guideline (SAMG) Program

Another severe accident initiative that has been undertaken by Duke is the development and implementation of Severe Accident Management Guidelines (SAMG). In December 1997, Duke completed all the training and procedures for the SAMG program. This formal program makes use of available plant resources to manage severe accidents, should they occur. It includes diagnostic tools and severe accident management guideline documents for developing strategies during an event to arrest core damage progression and mitigate fission product releases in the event of a severe accident. SAMG training is given to Emergency Response Organization personnel to provide an understanding of severe accident phenomenon and the use of the tools and guideline documents.

This SAMG program achieves an incremental risk reduction capability without reliance on additional hardware and resources.

TABLE 2-1 Risk Reduction Measures Implemented At McGuire

Past Studies	Alternatives Implemented As A Result Of Findings From Study
McGuire PRA initial study	Alternatives implemented as a result of the original McGuire PRA analysis: • Procedural guidance for operator's use was developed and implemented to better cope with a loss-of-nuclear service water event. • Operator actions for the loss of ac power procedure were prioritized such that the action to locally isolate the containment ventilation unit condensate drain line could be taken reliably. • Another plant enhancement related to a potential flooding condition in the auxiliary feedwater pump room. Expansion joints in the nuclear service water piping located in this room were discovered not to include a metal collar to limit the leakage. Thus, to reduce the likelihood of a large flooding event from this source, the expansion joints have been subsequently fitted with a collar to limit the leak rate.
The McGuire IPE study	Alternatives implemented as a result of the McGuire IPE results included modifications to procedures to: • direct operators to not restart reactor coolant pumps while in plant emergency procedure for inadequate core cooling conditions with no secondary side heat removal and the pressurizer PORVs are not open. With no secondary side heat removal and pressurizer PORVs closed, the forced circulation of very hot gases from the core at high pressure could overstress the steam generator tubes, creating a containment bypass situation. Additional procedural guidance to permit pump startup only when the stream generator tubes are covered with a mixture level has been implemented. • exercise the nuclear service water cross-connect valves between Unit 1 and 2 during each refueling outage. • an Emergency Diesel Generator System Reliability Centered Maintenance study was performed providing several recommendations (i.e., hardware modifications and changes to the maintenance program), which were implemented to enhance the reliability of the Emergency Diesel Generator System. • training exercises were performed to demonstrate that the operators can activate the SSF within 10 minutes. • In addition, the sump recirculation phase of the loss-of-coolant accident mitigation relies upon the FWST "Lo" level and "Lo-Lo" level signals. The span of the transmitters was scaled to the 0-160" range to minimize the span error of the instrumentation. With normal FWST level of 460", this instrument was susceptible to an undetected "failed-high" or "failed as-is" failure mode during normal operation. Therefore, the FWST level instrument span has been expanded to the full range to reduce the contribution from this failure mode to the sump recirculation failure.
The McGuire IPEEE study	Alternatives implemented as a result of the McGuire IPEEE results include several modifications to plant based on fire, tornado and seismic analysis which are contained in the McGuire IPEEE Report [Reference 2.4]. Those plant enhancements already completed include such items as adding spacers between Diesel Generator batteries and racks, adding grout between Component Cooling Heat Exchangers saddle base and concrete curb, trimming grate around Steam Vent valves, installing missing bolts to Upper Surge Tanks, modifying Turbine Driven Auxiliary Feedwater Pump Control Panel to avoid seismic interaction with pipe, replacing or cleaning and recoating corroded nuts on Auxiliary Feedwater Condensate Storage Tank anchor bolts, tighten arc barrier connections inside Main Control Boards. In addition, procedural guidelines have been developed to secure movable equipment and structures to prevent potential seismic interactions.

3.0 Methodology For Identifying Additional SAMAs

The analysis methodology selected for this analysis involves identifying those severe accident mitigation alternatives, which would have the most significant impact on reducing core damage frequency and person-rem risk. The approach used in this analysis consists of:

- developing the information on the current risk profile from the McGuire PRA Revision 2 results showing the distribution of the core damage frequency and person-rem risk (see Sections 4.1 and 5.1),

- identifying potential severe accident candidates for consideration of additional severe accident mitigation alternatives, and screening out those potential severe accident mitigation alternatives with low or marginal benefit (see Sections 4.2 and 5.2),

- further eliminating those alternatives whose implementation would not be expected to be cost-beneficial (see Sections 4.3 and 5.3),

- performing a cost-benefit analysis on the final set of potential alternatives to determine whether or not the implementation of the alternatives would be cost-beneficial (see Sections 4.4 and 5.4),

- finally, integrating the overall results and current initiative, and determining whether any further severe accident mitigation alternatives should be applied for license renewal (see Sections 6.0 and 7.0).

The current severe accident risk results are available from the 1997 update of the McGuire PRA Revision 2 [Reference 3.1]. As before, this update constitutes a full-scope Level 3 PRA with the analysis of both internal and external events. This McGuire PRA Revision 2 update provides a relatively current profile of the severe accident risk for McGuire characterized by (i) core damage frequency - the risk of core damage severe accidents which could release substantial fission products and (ii) person-rem risk - the risk of release of significant fission products offsite given a core damage accident. For this analysis the person-rem risk results are updated using the MELCOR Accident Consequence Code System (MACCS2) computer code with more recent meteorological data (1999 data) and 50-mile population estimates for the year 2040.

4.0 SAMAs Considered For Core Damage Frequency Reduction

The following sections explain how the current McGuire PRA results are evaluated for potential SAMAs to reduce core damage frequency. Section 4.1 describes the current McGuire core damage frequency profile. Section 4.2 defines the process of selecting the top cut sets for consideration of SAMAs based on contribution to core damage frequency. Section 4.3 provides the analysis of potential SAMAs where the seismic and non-seismic initiators are examined separately since there is a distinct difference in the amount of plant damage in the event of such accident initiators. After examining the cut sets, an additional approach to identifying potential SAMAs beyond those selected from evaluating the cut set listings is applied by reviewing the basic event importance ranking. This basic event importance ranking provides a means of determining if some individual basic events contribute significantly to the core damage frequency that may not have been identified in the cut set review. Finally, Section 4.4 provides the cost-benefit analysis for selected SAMAs.

4.1 Current McGuire Core Damage Frequency Profile

The current calculated total (internal and external initiating events) core damage frequency for McGuire is 4.9E-05 per year[Reference 3.1]. The following presents the total core damage frequency distributed among the identified internal and external events.

The internal events represent about 57% of the total core damage frequency as follows:

Initiating Events	Frequency
Transients (Reactor Trips, Loss of Main Feedwater, Loss of Operating 4 kV ac Bus, Loss of RN, etc.)	1.5E-05 /yr
LOCAs (Small, Medium, and Large)	1.1E-05 /yr
Internal Flood	8.7E-07 /yr
Anticipated Transient Without Scram	1.5E-07 /yr
Steam Generator Tube Rupture	7.8E-10 /yr
Reactor Pressure Vessel Rupture	1.0E-06 /yr
Interfacing-Systems LOCA	2.2E-07 /yr
Total Internal	**2.8E-05 /yr**

The external events represent about 43% of the total core damage frequency as follows:

Initiating Events	Frequency
Seismic	1.1E-05 /yr
Tornado	6.5E-06 /yr
Fire	2.9E-06 /yr
Total External	**2.1E-05 /yr**

A review of the detailed distribution shows that the leading contributor to the total core damage frequency are the seismic initiators.

4.2 Identification Of Potential SAMAs

The process of identifying a preliminary list of potential severe accident sequences for consideration of additional alternatives makes use of the most recent update of the McGuire PRA Level 1 results. The McGuire PRA Revision 2 report lists the top 100 cut sets (severe accident sequences) based on internal initiators and a top 100 list of cut sets for external initiators ranked by contribution to total core damage frequency. This list of 200 severe accident sequences includes all potential core damage accident sequences with at least a 0.06% contribution to the total core damage frequency. Therefore, this list will be the starting point for identifying which severe accident sequences contribute the most to the core damage frequency for McGuire, which may need to be considered for additional SAMAs.

As previously stated, the preliminary list of 200 internal and external cut sets contain severe accident sequences contributing at least 0.06%. Additionally, some cut sets contributing as little as 0.05% to the total core damage frequency are also included. This is a comprehensive list of potential severe accident sequences identified for the McGuire plant. Furthermore, most of the accident sequences contained in this listing are very small contributors to the total core damage frequency (< 1%), indicating that little benefit can be gained in reducing the core damage frequency for these sequences. For this analysis, a core damage frequency cutoff value of 3.5E-07 (for internal and external initiators) is applied as a method of screening out those severe accident sequences for consideration of SAMAs. It is assumed that the implementation of alternatives for sequences with core damage frequency contributions below these cutoff values will provide low or marginal benefit. This assumption is conservative because there are no SAMAs identified as cost-beneficial to implement for the cut sets above this cutoff value, and it is expected this will be the case for the cut sets below this cutoff value.

4.3 Analysis Of Potential SAMAs

The approach selected for this portion of the analysis (potential SAMAs to reduce core damage frequency) is to calculate the value of the total averted risk (including averted public exposure, averted onsite cleanup cost, averted onsite exposure risk, and averted offsite property damage) for each alternative. It relies on the NRC's Regulatory Analysis Guide [Reference 4.1] to convert public health risk (person-rem) into dollars to estimate the cost of the public health consequences. The requirement established in this guide is to use $2000 per person-rem to convert public heath consequences to dollars (not indexed to inflation).

This analysis divides the potential severe accident sequences for consideration of SAMAs into two sections: (1) seismic initiator sequences, and (2) non-seismic initiator sequences.

Seismic Initiators

In the McGuire IPEEE study, the seismic analysis was conducted by considering a distribution of equipment failure probabilities over various earthquake levels. The IPEEE analysis generates many cut sets that are grouped into particular plant damage states (PDSs). Therefore, the seismic initiator cut sets given in Table 6.1.3-2 of Reference 3.1 are the total probability of the cut sets in each PDS category rather than the individual cut set probabilities as in the case of the non-seismic events.

The following paragraphs explain how the McGuire-specific parameters are derived in order to calculate the total averted cost for the seismic initiator severe accident sequences.

Averted Public Exposure (APE)

The McGuire PRA Level 2-3 analysis maps each seismic initiator PDS into the various containment failure modes and release categories, and then presents the public health risk (person-rem) on a frequency weighted basis. The estimated maximum amount of annual person-rem risk associated with a particular seismic initiator cut set is calculated from the person-rem risk and core damage frequency for the PDS attributable to the seismic initiator. For example, the "seismic initiator causes PDS 7PI" severe accident sequence core damage frequency is estimated to be 9.6E-06 per year. The public health risk results from the Level 3 analysis estimates the conditional person-rem risk for PDS 7PI to be 3.7E+05 person-rem. Therefore, the total person-rem risk attributable to the "seismic initiator causes PDS 7PI" is determined by multiplying the core damage frequency for PDS 7PI by the conditional person-rem for PDS 7PI. This is demonstrated below:

Total Person-rem Risk = 9.6E-06 yr^{-1} $\times$ 3.7E+05 person-rem = <u>3.6 person-rem/yr</u>

Some risk will always exist, even when increasing the seismic ruggedness of many plant components/systems, because there is no way to completely eliminate the risk associated with seismic events. However, for this analysis an assumption is made that the implementation of plant enhancements for seismic events will completely eliminate the risk. The following equation is used to determine the value of the averted risk to the public:

Value Of Averted Risk = (\$2000/person-rem) $\times$ (Total Person-rem Risk)

The above equation calculates the value of averted risk on an annual basis. Therefore, a method of "discounting" is used to calculate the "present value" or "present worth of averted risk" based on a specified period of time. For this analysis, a discount factor of 7% as described in the NRC Regulatory Analysis Technical Evaluation Handbook [Reference 4.2] is used to determine the present worth of averted risk over the 20 year license renewal period for McGuire. This results in a multiplication factor of approximately 11:

Averted Public Exposure = (11) × ($2000/person-rem) × (Total Person-rem Risk)

Therefore, averted public exposure is calculated using the following equation:

$\boxed{\text{APE for 20-year license renewal period} = \$2.20E+04 * (\text{Change in annual Risk})}$ (Eq. 4-1)

<u>Averted Onsite Cleanup Cost (ACC)</u>

The estimated cleanup and decontamination cost for severe accidents is $1.5 billion (from NUREG/BR-0184 page 5.42). This cost is the sum of equal costs over a 10-year cleanup period. At a 7% discount rate, the present value of this stream of costs is $1.1 billion.

The net present value of cleanup and decontamination over the license renewal period is estimated from (equation from NUREG/BR-0184 page 5.43):

$U_{CD} = [\$1.1E+09/0.07][1 - \exp(-0.07 * 20)]$

$U_{CD} = \$1.18E+10$

Then,

$\boxed{\text{ACC for 20-year license renewal period} = \$1.18E+10 * (\text{Change in annual CDF})}$ (Eq. 4-2)

<u>Averted Onsite Exposure Cost (AOE)</u>

Assume a discount rate of 7% over the 20-year license renewal period.

<u>Immediate Dose (see NUREG/BR-0184 pages 5.30 – 5.33)</u>

$W_{IO} = \$2000/\text{person-Rem} * 3300 \text{ person-Rem} * [1 - \exp(-0.07 * 20)]/0.07 * (\text{Change in CDF})$

where, 3300 person-Rem = best estimate (from NUREG/BR-0184 page 5.30)

$W_{IO} = \$7.10E+07 * (\text{Change in annual CDF})$

<u>Long-Term Dose (see NUREG/BR-0184 pages 5.31 – 5.33)</u>

$$W_{LTO} = \$2000/\text{person-Rem} * 20{,}000 \text{ person-Rem} *[(1 - \exp(-0.07 * 20))/0.07] * [(1 - \exp(-0.07 * 10))/(0.07 * 10)] * (\text{Change in CDF})$$

where, 20,000 person-Rem = best estimate (from NUREG/BR-0184 page 5.31)
Assume the doses accrue over a 10-year period

$W_{LTO} = \$3.10E+08 * (\text{Change in annual CDF})$

AOE = W_{IO} + W_{LTO} = ($7.10E+07 + $3.10E+08) * (Change in annual CDF)

AOE for 20-year license renewal period = $3.81E+08 * (Change in annual CDF) (Eq. 4-3)

Averted Offsite Property Damage Cost (AOEC)

In 1990 dollars ≈ $2.46E+08 (assumed from NUREG/BR-0184 Table 5.6 on page 5.38)

Inflating to the year 2000 dollars ≈ $3.64E+08 (assume 4% inflation)

Assume a 7% discount rate for the 20-year license renewal period

AOEC = [$3.64E+08/0.07][1 – exp(-0.07 * 20)] * (Change in CDF)

AOEC for 20-year license renewal period = $3.92E+09 * (Change in annual CDF) (Eq. 4-4)

The above methodology is repeated for each of the remaining seismic initiator severe accident plant damage listed in the top 100 external cut sets [Table 6.1.3-2 of Reference 3.1]. The results are presented in Table 4-1.

Considering that the averted risk value is approximately $275,000 (see Table 4-1), the risk reduction achievable is indeed small and that the cost of substantial upgrades in the plant systems seismic ruggedness is very large (at least several million dollars). Therefore, seismic related SAMAs are eliminated from further consideration.

Non-Seismic Initiators

The following paragraphs explain how the McGuire-specific parameters are derived, in order to calculate the averted cost to the public for the non-seismic initiators.

The non-seismic initiator severe accident sequences (cut sets) contain basic events modeling the different types and combination of failures related to the severe accident sequence. Since most of the alternatives under consideration in this analysis have the potential to impact more than one severe accident sequence, it is necessary to determine the cumulative risk reduction achievable by each SAMA. This is performed by identifying which basic events in the cut sets would be affected by the implementation of a particular SAMA and conservatively assuming that the basic event(s) would be completely eliminated by the SAMA. The resulting change in core damage frequency from setting the basic event(s) to a value of zero provide the maximum risk reduction for that particular SAMA. For example, the basic event TRECIRCDHE (operators fail to establish high pressure recirculation following a LOCA) is associated with several "LOCA cut sets with failure of operators to initiate high pressure recirculation". Since several severe accident sequences have the potential to be impacted by the implementation of the alternative (automatic swap over to high pressure recirculation), an assumption is made to set the basic event TRECIRCDHE to zero to determine the maximum core damage frequency reduction achievable. In this case the maximum core damage frequency reduction from implementing the SAMA is 1.0E-05 per year. This new cut set file is used to generate a new conditional probability matrix, which is then processed through the PRA Level 3 risk analysis to estimate the new person-rem risk. This new person-rem risk is subtracted from the base case person-rem risk (13.5 person-rem) to determine the maximum risk reduction achievable. For the example of the TRECIRCDHE event the new person-rem risk is estimated to be 13.1 person-rem. Therefore, the maximum risk reduction for this SAMA is estimated to be 0.4 person-rem (13.5 minus 13.1).

Some risk will always exist, even when implementing an alternative, because the system is not expected to be 100% reliable. However, for this analysis an assumption is made that the implementation of an alternative for a severe accident sequence will completely eliminate the risk. The equations presented above (Eq. 4-1 through Eq. 4-4) are used here to determine the "**Present Worth Of Averted Risk**". These values represent the upper limit of "averted risk". Table 4-2 provides a list of the seven SAMAs considered to reduce core damage frequency, total person-rem risk, and present worth of averted risk calculated for each candidate applying the method discussed above.

As seen from Table 4-2, the seven potential SAMA candidates have a present worth of averted risk in the range of $18,000 to $250,000. The cost to implement most of the alternatives listed in Table 4-2 for McGuire will be greater than $1 million, based on the review of other industry cost estimate studies [Reference 4.3] applicable to McGuire. Comparing these cost estimates to the present worth of averted risk presented in Table 4-2, shows that the cost to implement most of these alternatives will far exceed the present worth averted risk. However, for two potential SAMAs listed in Table 4-2:

1. install third diesel, and
2. increase test frequency of Standby Makeup Pump flow path (currently tested quarterly)

cost estimates have been performed for McGuire (see Section 4.4) to determine whether or not the alternative is cost-beneficial. There are two reasons why these alternatives are selected for McGuire-specific cost estimates. First, there is no readily available information on estimated cost to implement similar types of alternatives; and second, the basic events associated with these alternatives are seen to have a Fussell-Vesely (F-V) importance measure of several percent, as seen from Table 6.1.3-3 of Reference 3.1.

Basic Event Importance Ranking

This portion of the analysis presents another approach to identifying potential SAMAs beyond those selected from evaluating the cut set listings. This involves (1) reviewing the basic event importance ranking list [Table 6.1.3-3 of Reference 3.1] for events of significant F-V values, which are not captured in Table 4-2, and (2) identifying any additional SAMAs that could be implemented to reduce the core damage frequency contribution from these events. This will provide a more complete review of potential SAMAs, which should be considered, for implementation.

A review of the importance ranking of the basic events reveals that two external initiating events (seismic and tornadoes) contribute significantly to the core damage frequency. Since seismic and tornado initiators are acts of nature, their frequency of occurrence cannot be reduced.

For the initiating event "Loss of RN" the core damage frequency contribution due to a total loss of Nuclear Service Water (RN) is obtained from a fault tree solve. The fault tree solve for this initiator generated a large number of cut sets representing numerous combinations of equipment/ operator failures. Based on a review of these cut sets and the various types of failures contained in these cut sets, a possible way of reducing the frequency of this event occurring is to install a third train of RN. Obviously, the cost to perform this modification will far exceed the benefit of core damage frequency reduction.

Another initiating event showing up as important in the importance ranking is "Vital I&C Fire Causes a Loss of RN". This initiating event results in a failure of electrical cables for both trains of RN pumps. The IPEEE fire analysis looked at ways to reduce the plant's vulnerability to fire initiating events. The results of the IPEEE analysis states that there are no unacceptable risks or outliers identified by the IPEEE fire protection walkdown. Duke Energy continues to place emphasis on the control of combustible materials, workers awareness of jobs that may present a fire hazard, and adequate fire protection. In addition, McGuire has three potential ways of mitigating this type of initiating event: (1) use backup cooling from the Containment Ventilation Cooling Water (RV) System, (2) cross-connect to other unit RN system, and (3) use the SSF.

Furthermore, the importance ranking shows that the "Loss of Offsite Power - LOOP" initiator contributes significantly to the core damage frequency. A lot of work has already been done as a result of the original McGuire PRA to address the LOOP initiator. Enhancements to the station blackout procedures and operator training have been implemented to reduce the likelihood and consequences of LOOPs. Duke continues, through the PRA update process, to investigate other improvements that can be made to further reduce the risk significance of these events.

Another initiating event showing up as important in the importance ranking is turbine building fire. The IPEEE fire analysis looked at ways to reduce the plant's vulnerability to fire initiating events. Numerous recommendations from the fire analysis have been made to improve fire protection and reduce the chance of a fire occurring. Duke continues to place emphasis on the control of combustible materials, workers awareness of jobs that may present a fire hazard, and adequate fire protection.

Duke has and continues to investigate ways of reducing the frequency of initiating events and mitigating the potential damages associated with such events. Based on the findings of these investigations, plant enhancements that could reduce the impact of such events have been implemented where reasonably possible. (See Table 2.1)

The remaining basic events listed in the importance table [Reference 3.1], were reviewed for potential SAMAs. Duke determined that the cost to implement any alternatives to mitigate or eliminate the consequences of the events would far exceed the averted risk benefit. Therefore, no additional SAMAs are considered for implementation.

4.4 Cost-Benefit Analysis For Selected SAMAs

In Section 4.3 two alternatives were identified for detailed cost estimate analyses due to the lack of information on the cost of implementation and the basic event importance measure associated with these alternatives. The selected alternatives are: (1) Install third diesel, and (2) Increase test frequency of Standby Makeup Pump flow path – currently tested on quarterly basis.

Therefore, the purpose of this portion of the analysis is to perform a cost-benefit analysis on the selected alternatives identified above, using McGuire-specific cost estimates.

Install third diesel

A design alternative that could reduce the core damage frequency associated with loss of offsite power events is to install a third diesel. In September 1995 a design study was performed to evaluate the costs associated with adding an alternative AC power source (installing a third diesel) at McGuire and Catawba. In this design study the cost estimate includes engineering, equipment and material, contracts, and installation craft resources (along with O&M costs). The results of the cost estimate analysis to install a third diesel is approximately $2 million. Therefore, the cost of implementing this alternative will far out weigh the benefit of averted risk worth (maximum benefit for this alternative is ~$200,000 from Table 4-2) making this alternative cost prohibitive.

Increase test frequency of Standby Makeup Pump flow path

The current test frequency of the Standby Makeup Pump flow path is quarterly. From the McGuire PRA results, the filter restricting flow due to clogging dominates this flow path failure. The failure rate of this filter is obtained from a generic type code failure rate, which is believed to be much higher than the true failure rate for the Standby Makeup Pump filter. The failure rate developed for the type code data base is for a system with continuous raw water flow through a filter. The Standby Makeup Pump system does not operate continuously; therefore, since flow is not continuously passing through the filter and the water contained in the Standby Makeup Pump system is clean water, the failure rate of this filter due to clogging is expected to be much less than the type code value. However, if the test frequency for this flow path is increased from quarterly to monthly, then the exposure time is reduced significantly in the event of the filter clogging and the likelihood of the filter restricting flow could be mitigated due to early detection of any potential clogging problems. The results of the cost estimate analysis to increase the test frequency of the Standby Makeup Pump flow path is approximately $435,000 (over the 20-year license renewal period). Therefore, the cost of implementing this alternative will far out weigh the benefit of averted risk worth (maximum benefit of this alternative is ~$40,000 from Table 4-2) making this alternative cost prohibitive.

TABLE 4-1 Top 4 Seismic Initiator Severe Accident Sequences

Seismic Initiator Severe Accident Sequences	Change in CDF (yr^{-1})	Change in Person-rem Risk	Averted Public Exposure	Averted Onsite Cleanup Costs	Averted Onsite Exposure	Averted Offsite Property Damage	Total Present Worth
Seismic initiator causes PDS 7PI	9.6E-6	3.6 (9.6E-06 yr^{-1} × 3.7E+05 person-rem)	$7.9E+04	$1.1E+05	$3.7E+03	$3.8E+04	~ $2.3E+05
Seismic initiator causes PDS 7DI	1.5E-6	0.5 (1.5E-06 yr^{-1} × 3.4E+05 person-rem)	$1.1E+04	$1.8E+04	$5.7E+02	$5.9E+03	~ $3.5E+04
Seismic initiator causes PDS 7PL	9.6E-8	< 0.1 (9.6E-08 yr^{-1} × 2.2E+05 person-rem)	< $2.2E+03	$1.1E+03	< $1.0E+02	$3.8E+02	< $4.0E+03
Seismic initiator causes PDS 7LI	7.3E-8	< 0.1 (7.3E-08 yr^{-1} × 3.0E+05 person-rem)	< $2.2E+03	$8.6E+02	< $1.0E+02	$2.9E+02	< $4.0E+03

TOTAL ≈ 4.1 person-rem $ 275,000

TABLE 4-2 Top 7 SAMAs Considered To Reduce CDF

SAMA #	Potential Alternative	Severe Accident Sequences (Basic Event)	Change in CDF (yr^{-1})	Change in Total [1] Person-rem Risk	Averted Public Exposure	Averted Onsite Cleanup Costs	Averted Onsite Exposure	Averted Offsite Property Damage	Total Present Worth[2]	Cost of Alternative (2001 dollars)
1	Man Standby Shutdown Facility (SSF) 24 hours a day with a trained operator This SAMA would eliminate the time factor associated with an operator being dispatched to the SSF. Therefore, for this analysis it is assumed that the DHE events associated with the operators failing to align SSF for operation in time are completely eliminated since there would be no transition time associated with dispatching an operator to start the SSF.	• Loss of RN, failure of operators to align SSF for operation, filter (Standby Makeup Pump) restricts flow, failure to align RV Cooling/other Unit RN • Vital I&C Fire causes a Loss of RN, failure of operators to align SSF for operation, failure to use other Unit or remote control during fire • Loss of 4160V Essential Bus and failure to align SSF for operation (NNVSSFADHE) AND • Tornado causes LOOP, DG 1A and 1B fail to fun, operators fail to initiate SS Sys. operation (NNVSSFBDHE)	1.1E-5	3.2	$7.0E+04	$1.3E+05	$4.2E+03	$4.3E+04	$2.5E+05	>$5 M
2	Install automatic swap over to high pressure recirculation. This SAMA would eliminate the operator action required for manual swap over – DHE event.	LOCA cut sets with failure of operators to establish high pressure recirculation (TRECIRCDHE)	1.0E-5	0.4	$8.8E+03	$1.2E+05	$3.8E+03	$3.9E+04	$1.7E+05	>$1 M
3	Install automatic swap to RV Cooling/other Unit RN system upon loss of RN This SAMA would eliminate the operator action required to manually align backup cooling to NV pumps.	Loss of RN, failure of operators to align SSF for operation, filter (Standby Makeup Pump) restricts flow, failure to align RV Cooling/other Unit RN (RNUNIT2RHE)	8.8E-6	1.2	$2.6E+04	$1.0E+05	$3.4E+03	$3.4E+04	$1.7E+05	>$1 M
4	Install third diesel For this SAMA it is assumed that failures associated with the two diesels already installed (run, start and common cause failures) would be eliminated.	Tornado causes LOOP, DG 1A and 1B fail, and operators fail to initiate SS Sys. operation (JDG001ADGR + JDG001BDGR + JDG001ADGS + JDG001BDGS + JDG1ARNCOM)	8.4E-6	3.1	$6.8E+04	$9.9E+04	$3.2E+03	$3.3E+04	$2.0E+05	>$2 M
5	Install automatic swap to other Unit	Vital I&C Fire causes a Loss of RN, failure of operators to align SSF for operation, failure to use other Unit or remote control during fire (FIREFLDRHE)	2.9E-6	1.1	$2.4E+04	$3.4E+04	$1.1E+03	$1.1E+04	$7.1E+04	>$1 M
6	Increase test frequency of Standby Makeup Pump flow path (currently tested quarterly)	Loss of RN, failure of operators to align SSF for operation, filter (Standby Makeup Pump) restricts flow, failure to align RV Cooling/other Unit RN (NNVSMUPFLF)	1.8E-6	0.5	$1.1E+04	$2.1E+04	$6.9E+02	$7.1E+03	$4.0E+04	>$ 0.4 M
7	Replace reactor vessel with stronger vessel	Failure of reactor pressure vessel with failure to prevent core damage following an reactor pressure vessel failure (RPV)	1.0E-6	< 0.1	< $2.2E+03	$1.2E+04	$3.8E+02	$3.9E+03	<$1.8E+04	>$1 M

[1] Total Person - risk includes internal and external (non-seismic) events
[2] The Total Present Worth values are calculated from an external spreadsheet and may different slightly when performing hand calculations due to round off.

5.0 SAMAs Considered For Person-rem Risk Reduction

5.1 McGuire Person-rem Risk Profile

In the event of a severe accident, a certain amount of person-rem risk would be associated with various types of containment failure. The containment failure modes of concern are those that have the potential for early release of fission products to the public such as early containment failures, isolation failures, and containment bypass (steam generator tube rupture – SGTR, and interfacing systems LOCA - ISLOCA).

The McGuire PRA Level 1/2 results presented in this analysis are from the current McGuire PRA (Revision 2). The results of the current McGuire PRA Level 2 analysis show that the most likely containment failure mode is relatively benign failure by late containment failure. This containment failure mode occurs many hours after core melt has occurred allowing time for mitigative actions to be taken such as recovering vital pieces of equipment for core debris cooling and containment heat removal, and implementing evacuation strategies. For the McGuire containment the conditional probability of having an early release of fission products to the public from early containment failures, isolation failures, and containment bypass following a severe accident is estimated to be less than 9%.

The McGuire PRA Level 3 results are updated for this analysis using a different consequence analysis computer code, more recent meteorological data, and projected population estimates as described below. For this analysis, the McGuire severe accident person-rem risk results were generated with the MACCS2 (MELCOR Accident Consequence Code System – Reference 5.1) computer code. The plant-specific input to the MACCS2 code includes McGuire core radionuclide inventory, emergency response evacuation modeling based on the McGuire evacuation time estimate studies, release category source terms from the McGuire PRA Rev. 2 analysis, site meteorological data (1999 met data), and projected population distribution (within 50-mile radius) for the year 2040. The McGuire annual person-rem risk result from the MACCS2 code for the 50 mile population is 13.5 whole body person-rem. The internal events account for approximately 6.0 whole body person-rem per year at 50 miles. The external events account for approximately 7.5 whole body person-rem per year at 50 miles. For external events, the major source of risk is seismic which is dominated by postulated earthquakes with accelerations (0.3g - 0.5g) much greater than the design basis earthquake. In general, the risk measures calculated show very low risk for the health and safety of the public.

5.2 Identification Of Potential Containment-Related SAMAs

For this portion of the analysis, other industry studies were used to obtain a preliminary list of containment improvement alternatives to be considered for McGuire. The Watts Bar SAMDA analysis [Reference 4.3] identified several potential alternatives that would enhance the ability of the containment to withstand challenges associated with late hydrogen burn, late overpressurization, basemat melt through, and containment bypass. The following nine design changes were identified for the Watts Bar analysis:

1. Install deliberate ignition system - provide an AC- and DC-independent system to burn combustible gases generated in containment during a severe accident to eliminate containment failures due to hydrogen combustion.
2. Install reactor cavity flooding system - provide the capability to flood the reactor cavity of the containment to reduce the possibility of direct core debris contact with containment.
3. Install filtered containment vent system - provide the capability to vent the containment to an external filter to reduce the frequency of and consequences of late containment failures.
4. Install core retention device - to prevent direct impingement of core debris onto the containment during a high pressure melt ejection.
5. Install containment inerting system - to inert the containment atmosphere to prevent combustion of hydrogen and carbon monoxide during severe accidents.
6. Install additional containment bypass instrumentation - install additional pressure-monitoring instrumentation between the first two isolation valves on low-pressure injection lines, residual heat removal suction lines, and high-pressure injection lines. This would improve the ability to detect leakage or open valves, which decrease the frequency of interfacing systems LOCA (ISLOCAs).
7. Install reactor depressurization system - provides capability to rapidly depressurize the reactor coolant system to reduce the threat of high pressure melt ejection and allow injection from low pressure systems.
8. Install independent containment spray system - provides a redundant containment spray system.
9. Install AC-independent air return fan power supplies - provides a redundant power supply to air return fans.

The following five additional alternatives considered for containment performance improvement were obtained from NUREG-1560 [Reference 5.2]:

10. Add procedures for direct reactor coolant system depressurization to prevent early containment failure associated with reactor vessel breach at high reactor coolant system pressure.
11. Add emphasis on isolation procedures in operator training.

12. Add procedures to cope with and reduce induced steam generator tube rupture (SGTR).
13. Add alternative, independent source of feedwater to reduce induced SGTR.
14. Add emphasis on increasing the likelihood of maintaining a coolable debris bed to prevent late containment failure due to overpressurization.

Combining the information gathered from the two studies mentioned above provides a preliminary list of 14 containment performance improvement alternatives to be considered for McGuire.

The following is the process used to refine the list of 14 containment performance improvement alternatives identified for consideration at McGuire:

- identify any alternatives that have already been implemented at McGuire, and
- identify any alternatives that are not applicable to McGuire's containment.

The current McGuire procedures satisfy the intent of Alternatives 10 and 11. Following the IPE study the plant procedure was modified to address the induced SGTR (Alternative 12). A significant part of the Severe Accident Management Guidance Program (SAMG) at McGuire emphasizes the importance of and provides guidance to the operators on depressurizing the reactor coolant system to prevent high pressure melt ejection. Also, the SAMG program provides guidance on putting water into the containment using plant resources to increase the likelihood of maintaining a coolable debris bed in the event of a severe accident. Thus Alternative 14 has been addressed through the SAMG program.

The alternative to "install reactor depressurization system" (Alternative 7) is for a plant that has limited reactor coolant system depressurization capability. McGuire has three PORVs located on the pressurizer, which provides sufficient depressurization of the reactor coolant system to pressures low enough to prevent high pressure melt ejection. Also, the SAMG program provides guidance on using the pressurizer PORVs to depressurize the reactor coolant system rapidly to prevent high pressure melt ejection. The estimated cost to install an additional reactor depressurization system from other studies is on the order of several million dollars [Reference 4.3]: therefore, this alternative is eliminated from further consideration in this analysis since very little benefit will be gained from the implementation of this alternative.

Thus, the preliminary list of 14 containment performance improvement alternatives considered for McGuire is reduced to nine potential candidates for cost-benefit analysis. The following section discusses the method used to determine if any of these nine alternatives are cost-beneficial to implement for the McGuire containment.

5.3 Analysis Of Potential Containment-Related SAMAs

The method used in this portion of the analysis is similar to the one presented in Section 4.3.

The following explains how the McGuire-specific parameters are derived in order to calculate the averted cost to the public based on implementation of containment performance improvements. The McGuire PRA Level 3 analysis calculates the estimated person-rem risk associated with each type of containment failure mode following a severe accident. As can be seen in Table 5-1, the results of the McGuire PRA analysis show that there are three containment failure modes contributing more to the annual person-rem risk than any of the other potential failure modes (ISLOCA – 2.6 person-rem, Early Containment failures - 5.5 person-rem, and Late Containment failures – 5.3 person-rem). These are evaluated in detail below.

The PRA Level 3 analysis reveals that almost all of the large early release frequency (LERF) is attributable to the ISLOCA initiator. The dominant ISLOCA initiator sequences involve the failure of at least two valves (i.e., valve ruptures, transfers position, operator error, etc.). The total CDF and person-rem risk associated with the ISLOCA initiators is 2.2E-07 per year and 2.6 person-rem, respectively. The estimated cost to implement additional containment bypass instrumentation is on the order of several million dollars [from Reference 4.3]. For this analysis if the assumption is made that the implementation of a containment performance improvement alternative will completely eliminate the ISLOCA risk, the total averted risk value is $61,000 (applying Eq. 4-1 through Eq. 4-4 of Section 4.3 – <u>APE</u> = 11 * $2000 * 2.6 person-rem/yr = <u>$57,200</u>, and <u>ACC, AOE, AOEC</u> = 2.2E-7 per yr * [$1.18E+10 + $3.81E+08 + 3.92E+09] = <u>$3542)</u>. Therefore, the estimated cost to implement additional containment bypass instrumentation to detect ISLOCAs far exceeds the theoretical maximum present worth of averted risk making the alternative very cost prohibitive even if McGuire's actual cost is significantly less than the referenced estimate.

From the McGuire PRA results, the containment isolation failure mode is dominated by loss of offsite power events. These sequences involve loss of power to motor-operated containment isolation valves and would require manual action to close the valve outside containment. The only feasible containment performance improvement alternative considered for this type of containment failure mode is adding emphasis on isolation procedures in operator training. This has already been implemented at McGuire per the McGuire IPE study.

The late containment failure mode for the McGuire plant is associated with sequences where containment sprays are lost and no recovery is possible. This leads to a buildup of pressure from steam and non-condensible gases over many hours until the containment fails. A containment performance improvement alternative that could reduce the person-rem risk associated with such failures is the installation of an independent containment spray system. From Reference 4.3 the estimated cost to implement such an alternative will be at least several million dollars. The present worth of averted risk for implementation of this alternative is estimated by assuming all 5.3 person-rem risk is eliminated for late containment failures. Then multiplying the 5.3 person-rem risk by $2000/person-rem yields an estimated averted risk value of $10,600, and multiplying this value by the discount multiplication factor of 11 gives an estimated present worth of $117,000. Therefore, based on the cost to implement this alternative this containment performance improvement will cost far more to implement than the value of the averted risk. Some benefit in reducing the early containment failure may be seen from this alternative but this would be expected to be small compared to the late containment failure benefit.

Furthermore, when considering the implementation of alternatives, it is important to evaluate the potential negative impacts of implementing alternatives as well as the positive benefits. For example, the containment performance improvement alternative considered in Table 5-1 (installing a reactor cavity flooding system) is intended to reduce the likelihood of basemat melt through by flooding the core material after reactor vessel failure. Even though the implementation of this alternative may reduce the likelihood of basemat melt through, any potential negative consequences have not been investigated.

Table 5-1 provides a list of the nine selected containment performance improvement alternatives considered for implementation at McGuire along with the percentage of the time a containment failure mode may occur given a severe accident, the total person-rem and present worth of averted risk estimates associated with each containment failure mode.

As seen from Table 5-1, the nine potential containment-related SAMAs have an averted risk worth in the range of $2200 to $121,000. The cost to implement any of the containment performance improvement alternatives listed in Table 5-1 for McGuire will range anywhere from a few million dollars to tens of millions of dollars based on the review of other industry cost estimate studies [Reference 4.3]. Comparing these cost estimates to the averted risk worth presented in Table 5-1 reveals that the cost to implement these alternatives will far exceed the averted risk worth. This conclusion applies even for those alternatives providing benefit to more than one type of containment failure mode.

For example, the six alternatives (install independent containment spray system, filtered containment vent, backup power to igniters, reactor cavity flooding system, backup power to air return fans, and containment inerting system) provide some benefit to more than one type of containment failure mode. As stated earlier, the installation of an independent containment spray system provides more late containment failure benefit than early containment failure benefit. But if this alternative is assumed to completely eliminate late and early containment failures, the cost of implementation would far exceed the averted risk value of ($117,000 + $121,000). This same conclusion is applied to each of the filtered containment vent alternative, backup power to igniters alternative, backup power to air return fans alternative, and containment inerting system alternative based on the cost of implementation versus the total averted risk value for early and late containment failures ($117,000 + $121,000). The cost to implement most of the alternatives listed in Table 5-1 for McGuire will be greater than $1 million, based on the review of other industry cost estimate studies [Reference 4.3] applicable to McGuire. Comparing these cost estimates to the present worth of averted risk presented in Table 5-1, shows that the cost to implement most of these alternatives will far exceed the present worth averted risk. However, for one potential SAMA listed in Table 5-1 (install reactor cavity flooding system) a cost estimate has been performed for McGuire (see Section 5.4) to determine whether or not the alternative is cost-beneficial.

5.4 Cost-Benefit Analysis For Containment-Related SAMAs

In Section 5.3 one alternative was identified for a McGuire-specific cost estimate analysis due to the lack of information on the cost of implementation and the potential containment performance improvement associated with this alternative. The selected alternative is: Install standpipe in containment for reactor cavity flooding.

Therefore, the purpose of this portion of the analysis is to perform a cost-benefit analysis on the selected alternative identified above, using McGuire-specific cost estimates.

Install Standpipe in Containment for Reactor Cavity Flooding

The accident mitigation goal associated with flooding the reactor cavity is to provide cooling to the core debris (invessel and exvessel). The current spill over elevation for water to enter the reactor cavity/incore instrumentation room from the containment sump at McGuire is approximately 13 feet. This elevation is at the reactor coolant system piping penetrations in the primary shield wall. The water volume necessary to increase the McGuire containment sump level to the spill over point of 13 feet and flood the reactor cavity is equivalent to two refueling water storage tank (FWST) volumes (~750,000 gallons). Therefore, prior to reactor vessel failure there are two options available for achieving this accident mitigation goal: (1) inject the initial FWST volume into containment and refill the FWST and inject that volume into containment, and (2) inject all available water sources into containment (i.e., FWST volume, cold leg accumulators, reactor coolant system volume, and ice). If an open standpipe is installed in the containment sump floor that allows water to spill over into the reactor cavity at an elevation much less than the current 13 foot elevation, but still maintain net positive suction head pump requirements for swap over to recirculation, then the likelihood of flooding the reactor cavity is increased. The results of the cost estimate analysis to install a standpipe in containment is at least $1 million. The maximum benefit from implementation of this alternative is estimated by assuming that early containment failures and basemat melt through are completely eliminated. From Table 5-1 this benefit is estimated to be ~$123,000 ($121,000 + $2200). Therefore, the cost of implementing this alternative will far out weigh the benefit of averted risk worth making this design alternative cost prohibitive.

TABLE 5-1 Potential Containment SAMAs Considered To Reduce Person-rem Risk

Containment Failure Mode (CFM)	Potential Containment Performance Alternatives To Mitigate CFM	Percentage Of Time Severe Accidents Will End In Particular CFM	Total Person-rem Risk	Present Worth Of Averted Risk
Late Containment Failures	1. Install independent containment spray system 2. Install filtered containment vent system 5. Install backup power to igniters 8. Install backup power to air return fans 9. Install containment inerting system	41 %	5.3	$117,000
Containment Bypass ISLOCA SGTR	3. Install additional containment bypass instrumentation (ISLOCA) 4. Add independent source of feedwater to reduce induced SGTR	< 1 % (ISLOCA and SGTR combined)	2.6 – ISLOCA < 0.1 – SGTR	$61,000 (ISLOCA) < $2200 (SGTR)
Early Containment Failures	1. Install independent containment spray system 2. Install filtered containment vent system 5. Install backup power to igniters 6. Install reactor cavity flooding system 8. Install backup power to air return fans 9. Install containment inerting system	7 %	5.5	$121,000
Basemat Melt Through	6. Install reactor cavity flooding system 7. Install core retention device	5 %	< 0.1	< $2200

6.0 Overall Results

Duke has evaluated potential plant enhancements that would further reduce the probability of severe accidents and the associated person-rem risk. The incremental safety benefit of implementing these plant enhancements has been analyzed by performing a public risk analysis. The results of the public risk analysis show that none of the hardware changes for severe accident mitigation alternatives considered for core damage frequency and person-rem reduction would be cost-beneficial to implement at McGuire. Most of the alternatives considered are associated with severe accident sequences of either low contribution to core damage frequency (< 5% of the total) or low risk (< 3 person-rem). From the results obtained, it is apparent that the dominant severe accident sequences are seismic initiators based on their total contribution to core damage frequency and person-rem risk. However, even the alternatives considered for these type initiators are found to be cost prohibitive because the cost to implement the alternatives far exceed the value of the public health risk averted.

In addition, Duke recently implemented two programs to manage the risk associated with severe accidents. The Maintenance Rule Program is currently aiding in identifying risk significant structures, systems and components to minimize failures that are maintenance preventable. Most recently, Duke's implementation of the Severe Accident Management Guidance (SAMG) Program provides guidance on arresting core damage and mitigating fission product releases to the public in the event of a severe accident. Some of the severe accident management guidance provided by the SAMG program include:

- depressurizing the reactor coolant system prior to reactor vessel failure, thus preventing a high pressure melt ejection and SGTRs,
- venting containment prior to containment failure due to overpressurization (controlled release versus an uncontrolled release of fission products),
- inject water into reactor building (containment) to cool core debris, etc.

The following table summarizes the severe accident mitigation alternatives and containment performance improvements considered for McGuire and the status of implementation:

TABLE 6-1 Summary Of Potential Alternatives Considered For McGuire To Reduce Core Damage Frequency & Person-rem Risk

Potential Alternative	Implemented or Not Implemented	Reason Not Implemented
Increase seismic ruggedness of many plant components/systems	Not Implemented	Not Cost Beneficial. The risk reduction achievable is small and that the cost of substantial upgrades in the plant systems seismic ruggedness is very large
Install automatic swap over to high pressure recirculation	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Install third diesel	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Man SSF 24 hours a day with a trained operator	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Install auto swap over to RV Cooling/other Unit RN System upon loss of RN	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Install automatic swap over to other Unit	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Replace reactor vessel with stronger vessel	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Increase test frequency of Standby Makeup Pump flow path from quarterly testing to monthly testing	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Install additional containment bypass instrumentation (ISLOCA)	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. SAMG Program addresses this issue.
Add independent source of feedwater to reduce induced SGTR	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Install backup power to igniters	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Install backup power to containment air return fans	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk
Add procedures for direct RCS depressurization	Implemented	Existing procedures adequate
Add emphasis on isolation procedures in operator training	Implemented	Existing procedures adequate

TABLE 6-1 Summary Of Potential Alternatives Considered For McGuire To Reduce Core Damage Frequency & Person-rem Risk (continued)

Potential Alternative	Implemented or Not Implemented	Reason Not Implemented
Add procedures to cope with and reduce induced SGTR	Implemented	Existing procedures adequate
Add emphasis on increasing the likelihood of maintaining a coolable debris bed	Implemented	Implemented through SAMG
Install containment inerting system	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. In addition, this alternative has the potential to increase the likelihood of containment failures at McGuire due to overpressurization.
Install reactor depressurization system	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. SAMG Program emphasize depressurizing RCS.
Install filtered containment vent system	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. SAMG Program provides guidance on venting strategy to minimize releases to public.
Install independent containment spray system	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. In addition, the alternative primarily reduces late containment failure. These occur many hours after core damage begins allowing plenty of time for recovery of containment heat removal equipment and implementation of SAMG strategies.
Install reactor cavity flooding system	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. SAMG Program provides guidance on putting water into containment for cooling the core debris. In addition, this alternative has the potential to increase the likelihood of containment failures at McGuire due to overpressurization from steam generation.
Install core retention device	Not Implemented	Not cost beneficial. Very expensive with extremely small impact on public health risk. SAMG Program provides guidance on putting water into containment for cooling the core debris.

7.0 Conclusions

Duke has performed a number of severe accident studies on McGuire and has implemented several plant enhancements to reduce the risk of severe accidents since the late 1980’s.

The results of the McGuire-specific analyses for severe accidents show that the total core damage frequency is estimated at 4.9E-05 per year, and the risk is estimated at 13.5 person-rem per year.

For the current residual severe accident risk, a SAMA analysis has been performed using PRA techniques and making use of industry studies and NRC reports providing guidance on performing cost-benefit analysis. This McGuire-specific analysis demonstrates that plant enhancements (severe accident mitigation and containment performance improvement) in excess of $2200 to $275,000 are not cost justified based on averted risk.

Because the environmental impacts of potential severe accidents are of small significance and because additional measures to reduce such impacts would not be justified from a public risk perspective, Duke concludes that no additional severe accident mitigation alternative measures beyond those already implemented during the current term license would be warranted for McGuire.

It is recognized that risk assessment studies are subject to varying degrees of uncertainty in the estimated core damage frequency, person-rem risk, and cost to implement alternatives. The results of this analysis show that the cost of implementing any of the alternatives is as much as several orders of magnitude higher than the estimated averted risk values. Therefore, no additional severe accident mitigation alternatives are cost-beneficial even when the uncertainties in the risk assessment process are considered.

8.0 References

Section 1.0

1.1 Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses, Supplement 1 to Regulatory Guide 4.2, U. S. Nuclear Regulatory Commission, Washington, D. C., September 2000.

Section 2.0

2.1 Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerabilities, USNRC, November 1988.

2.2 H. B. Tucker (Duke) letter dated November 4, 1991 to Document Control Desk (NRC), McGuire Units 1 and 2 Individual Plant Examination (IPE) Submittal, McGuire Nuclear Station, Docket Nos.: 50-369 and 50-370.

2.3 Nerses (NRC) letter dated June 30, 1994 to T. C. McMeekin (Duke), Evaluation of the McGuire Units 1 and 2 Individual Plant Examination (IPE) - Internal Events, McGuire Nuclear Station, Docket Nos., 50-369 and 50-370.

2.4 T. C. McMeekin (Duke) letter dated June 1, 1994 to Document Control Desk (NRC), Individual Plant Examination of External Events (IPEEE) Submittal, McGuire Nuclear Station, Docket Nos. 50-369 and 50-370.

2.5 Rinaldi (NRC) letter dated February 16, 1999 to H. B. Barron (Duke), Evaluation of the McGuire Units 1 and 2 Individual Plant Examination of External Events (IPEEE), McGuire Nuclear Station, Docket Nos., 50-369 and 50-370.

Section 3.0

3.1 H. B. Barron (Duke) letter dated March 19, 1998 to Document Control Desk (NRC), Probabilistic Risk Assessment, Individual Plant Examination, McGuire Nuclear Station, Docket Nos. 50-369 and 50-370.

Section 4.0

4.1 Regulatory Analysis Guidelines of the U. S. Nuclear Regulatory Commission, NUREG/BR-0058, Revision 2, Final Report, U. S. Nuclear Regulatory Commission, Washington, D. C., November 1995.

4.2 Regulatory Analysis Technical Evaluation Handbook, NUREG/BR-0184, Revision 2, Final Report, U. S. Nuclear Regulatory Commission, Washington, D. C., January 1997.

4.3 Final Environmental Statement: Related To The Watts Bar Nuclear Plant Units 1 and 2, NUREG—0498 Supplement 1, U. S. Nuclear Regulatory Commission, Washington, D. C., April 1995, Docket Nos. 50-390 and 50-391.

Section 5.0

5.1 Code Manual for MACCS2: User's Guide, Chanin, D. I., et al, NUREG/CR-6613. Volume 1, May 1998.

5.2 Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance, NUREG-1560, Summary Report, U. S. Nuclear Regulatory Commission, Washington, D. C., October 1996.

Attachment L

Letter from Christopher Goudreau, North Carolina Wildlife Resources Commission
to
William Miller, Duke Energy
dated May 4, 2001.

North Carolina Wildlife Resources Commission

Charles R. Fullwood, Executive Director

645 Fish Hatchery Road
Marion, NC 28752-9229
May 4, 2001

RECEIVED
MAY 08 2001
Duke Power
Environmental Engineering

Mr. William Miller
Duke Power
Environment, Health & Safety
P.O. Box 1006
Charlotte, NC 28201-1006

SUBJECT: McGuire Nuclear Station License Renewal

Dear Mr. Miller:

I have reviewed the Generic Environmental Impact Statement and the information you provided at our September 21, 2000 and May 2, 2001 meetings concerning the McGuire Nuclear Station license renewal.

The North Carolina Wildlife Resources Commission is not aware of any "new and significant information" for analysis pursuant to 10 CFR 51.53(c)(3)(iv).

Thank you for the opportunity to review and comment on this issue. We request that Duke Power keep us informed as the license renewal process continues.

Sincerely,

Christopher Goudreau
Hydropower Relicensing Coordinator

c: Frank McBride (NCWRC)

c:\mydata\word\habcon\duke\mcguire geis.doc

Mailing Address: Division of Inland Fisheries • 1721 Mail Service Center • Raleigh, NC 27699-1721
Telephone: (919) 733-3633 ext. 281 • Fax: (919) 715-7643

Attachment M

The Duke Power Annual Plan
September 1, 2000

THE DUKE POWER ANNUAL PLAN
SEPTEMBER 1, 2000

TABLE OF CONTENTS

INTRODUCTION:

Duke has developed an annual resource plan that will meet customers' energy needs with a combination of existing generation, customer demand-side options, short-term purchase power transactions, and self-build options. Duke will meet future capacity needs by assessing the supply and demand-side markets and determining the best way to acquire the needed resources.

OVERVIEW:

The Duke Power 2000 Annual Plan reflects commitment to meeting customers' need for a highly reliable energy supply at the lowest reasonable cost. Duke recognizes several trends that are key drivers in the plan:

- Robust wholesale purchased power markets have developed which provide a variety of products, opportunities and risks for both planners and market participants.

- Supply-side resource costs and construction lead times continue to make these resources cost effective and flexible options for planners.

- Customer incentives and expenses for demand-side resources continue to hamper their cost effectiveness.

The risks imposed and opportunities presented by an increasingly competitive industry demand that companies develop flexible resource portfolio strategies to meet customer energy needs in a reliable and cost-effective manner. The Duke Power 2000 Annual Plan represents a balanced strategy which incorporates the perspectives of customers, shareholders, and the public with options for flexibility.

The market for purchase power contracts has continued to expand and improve. Purchase power and self-build supply side resources are viable, complementary strategies for meeting customer energy needs reliably and at the lowest reasonable cost.

Recognizing the risks and uncertainties of the future, Duke has developed a resource acquisition strategy to meet near-term obligations in a manner that does not impose undue exposure to long-term financial burdens. Duke will review and select the most cost-effective options the market has to offer to meet customer needs in a reliable manner. Such options include purchased power options and self-build peaking and intermediate generation technologies.

The 2000 Annual Plan incorporates a 15-year load forecast, near-term purchase power contracts, existing generation, Demand-Side Management (DSM), and peaking and intermediate generation technologies. The plan is developed with the objective of minimizing revenue requirements with a planning reserve margin of 17 percent. The annual plan includes a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of projected reserve margins and a discussion of the adequacy of the transmission system.

The following information is supplied pursuant to NCUC order dated June 21, 2000 in Docket No. E-100, Sub 84, NCUC Rules R8-60 and R8-62(p) and the NCUC Order dated July 13, 1999 in Docket No. E-100, SUB 82 as well as the PSCSC Order No. 98-151, dated February 25, 1998, Order No. 98-502, dated July 2, 1998, in Docket No. 87-223-E and Section 58-33-430 of the Code of Laws of South Carolina.

RESERVE MARGIN EXPLANATION AND JUSTIFICATION:

Reserve margins are necessary to help ensure adequate resources will be available considering customer demand uncertainty, unit outages, and weather extremes. Appropriate levels of reserves are impacted by existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchase power market. In recent years, Duke has reduced its planning reserve margin requirements. The reduction was primarily due to increased availability of existing generation, shorter lead times for construction of new generation, and the emergence of new purchase power options. The additional flexibility of shorter lead time generation alternatives has enabled Duke to more effectively use these resources to satisfy reserve margin requirements. Reductions in planning reserves under these circumstances has allowed for a closer match between generation resource commitments and customer needs while maintaining reliability.

Based on Duke's operating experience with approximately 19,300 MW's of existing generation, 1,200 MW's of purchase power contracts, and 1000 MW's of interruptible Demand Side Management (DSM) resources, Duke adopted a planning reserve margin target of 17 percent in 1997. As Duke nears each peak demand season, there is a greater level of certainty regarding the customer load forecast and total system capability due to near term weather conditions and greater knowledge of generation unit availability. The Duke total system capability includes the expected capacity of each generating station and the net of firm purchases less sales. Changes to the total system capability associated with seasonal capacity re-ratings and scheduled outages reveal the expected amount of sustainable generation available to meet load requirements. This capacity is then utilized in evaluating the potential exposure to DSM activations. If necessary, Duke would acquire additional capacity in the short-term power market. The adjusted system capacity, along with the Load Control DSM capability, are used to satisfy Duke's NERC Policy 1 Reserve Requirements (see Appendix A) and contingencies. Contingencies include events such as higher than expected unavailability of generating units and increased customer load due to extreme weather conditions.

Duke continually reviews the generating system capability, level of potential DSM activations, scheduled maintenance, purchased power availability and transmission capability to assess Duke's capability to reliably meet the customer load.

For the past four years Duke Power has utilized a 17 percent planning reserve margin. Between June 1998 and July 2000, there have been 15 days where generating reserves dropped below 3 percent. Generating reserves do not include purchases or DSM. When purchases and DSM are added to generating reserves, the lowest margin of reserves was 12 percent. From 1997, Duke has had sufficient reserves to reliably meet customer load with limited need to activate interruptible programs. The following table illustrates Duke's limited use of interruptible capacity, including the summer of 2000 through July 31. Based upon successful operations utilizing the 17 percent planning reserve margin, Duke concludes that its continued use is appropriate at this time.

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
7/99 – 8/00	Air Conditioners	1 Load Test	170 – 200 MW	175 – 200 MW
7/99 – 8/00	Water Heaters	1 Load Test	6 MW	Included in Air Conditioners
7/99 – 8/00	Standby Generators	1 Capacity Need	70 MW	70 MW
		Monthly Test		
7/99 – 8/00	Interruptible Service	1 Communication Test	N/A	N/A
9/98 – 7/99	Air Conditioners	None		
9/98 – 7/99	Water Heaters	None		
9/98 – 7/99	Standby Generators	Monthly Test		
9/98 – 7/99	Interruptible Service	1 Communication Test	N/A	N/A
9/97 – 9/98	Air Conditioners	1 Load Test	180 MW	170 MW
9/97 – 9/98	Water Heaters	1 Communication Test	N/A	N/A
		1 Load Test	7 MW	7 MW
9/97 – 9/98	Standby Generators	2 Capacity Needs	68 MW	58 MW
		Monthly Test		
9/97 – 9/98	Interruptible Service	1 Communication Test	N/A	N/A
		1 Capacity Need	570 MW	500 MW
9/96 – 9/97	Air Conditioners	1 Communication Test	N/A	N/A
9/96 – 9/97	Water Heaters	None		
9/96 – 9/97	Standby Generators	4 Capacity Needs	62 MW	50 MW
		Monthly Test		
9/96 – 9/97	Interruptible Service	2 Communication Tests	N/A	N/A
		1 Capacity Need	650 MW	550 MW

TRANSMISSION SYSTEM ADEQUACY:

Duke Electric Transmission (ET) monitors the adequacy and reliability of the transmission system and its interconnections through analysis of internal transmission system models and participation in regional reliability groups. Corrective actions are planned and implemented in advance to ensure continued cost-effective high quality electric service is provided. Duke ET internal models cover the next ten years and are prepared in close coordination with Duke's resource planning and distribution personnel to accurately reflect available generating resources and load. The Duke ET internal model data is also used as input into industry models employed by regional reliability groups in their analyses.

Transmission system reliability is constantly monitored through evaluation of changes in load, generating capacity, transactions, or topography. Annually, a detailed screening of an internal model three years out is performed to identify any voltage or thermal loading violations of ET's Planning Guidelines. The screening methods are in compliance with Southeastern Electric Reliability Council (SERC) and North American Electric Reliability Council (NERC) planning guidelines. The annual screening results are used to evaluate a 10-year planning horizon that accounts for load growth, transmission reservations, and planned changes in generation and system topography. The screening results are a major input for the Transmission Asset Management Plan (TAMP). The TAMP controls the allocation of resources to ensure proper prioritization and funding of projects to maintain system reliability.

Duke ET participates in the following regional reliability groups for coordination of analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability:

1. VACAR – Carolina Power & Light (CP&L), Duke Power (DP), Fayetteville Public Works Comm., North Carolina Electric Membership Corporation (NCEMC), North Carolina Eastern Municipal Power Agency (NCEMPA), North Carolina Municipal Power Agency No. 1 (NCMPA1), South Carolina Electric & Gas (SCE&G), South Carolina Public Service Authority (SCPSA), Southeastern Power Administration (SEPA), Dominion Virginia Power, and Yadkin, Inc.
2. VAST – VACAR, American Electric Power (AEP), Southern and the Tennessee Valley Authority (TVA)
3. VEM – VACAR, East Central Area Reliability Council (ECAR) and the Mid-Atlantic Area Council (MAAC)
4. VSTO – VACAR, Southern, TVA and Oglethorpe

Each of these reliability groups evaluates the bulk transmission system to: 1) assess the interconnected system's capability to handle large firm and non-firm transactions, 2) ensure planned future transmission system improvements do not adversely affect neighboring systems and 3) ensure the interconnected systems' compliance with selected NERC Planning Standards.

Regional reliability groups normally participate in the evaluation of transfer capability and compliance to the NERC Planning Standards for the next peak load period through the next five to ten years. The regional reliability groups perform tests at sufficiently high transfer levels to verify satisfactory transfer capability is maintained for years in advance. Duke evaluates all requests for transmission reservation for impact on transfer capability and compliance with ET's Planning Guidelines. Studies, including transfer capability assessments, are performed to ensure transfer capability is acceptable and exceeds VACAR Reserve Sharing Agreement requirements. The VACAR Reserve Sharing Agreement ensures that all VACAR member control areas have sufficient generation to meet their largest single generation contingency. The TAMP process is also used to manage projects for improvement of transfer capability.

Duke ET's internal analyses, participation with industry reliability councils, and process for managing transmission system projects contribute to system security and reliable operation.

On July 18, 2000 CP&L Energy, Duke Energy and SCANA Corporation announced the formation of an independent regional transmission organization (RTO) in compliance with the Federal Energy Regulatory Commission's Order 2000. The RTO is to be known as GridSouth and would be responsible for operating and planning the transmission systems of the three companies.

Initially, the three utilities will continue to own their existing transmission networks, while the RTO assumes broad operational and planning responsibilities to ensure open and non-discriminatory access to the grid. The intent of the three companies is to create a framework that may lead to a broad, regional independent transmission company that spans the Southeast.

Historically, the three utilities have done an excellent job coordinating the planning and operation of their interconnected transmission systems to maintain a high degree of system reliability and adequacy. The formation of GridSouth, as the transmission operator for the combined transmission system, will further enhance the reliability of the interconnected systems. GridSouth will be uniquely positioned to coordinate not only the planning and operating activities of the three companies but to also coordinate the planning and operating activities with neighboring utilities and RTOs. This broader view may allow GridSouth to identify potential issues that the individual utilities previously may not have been able to identify.

The NCUC order dated June 21, 2000 in Docket No. E-100, Sub 84 required that the Annual Plan due September 1, 2000 include a discussion of efforts by the interested parties to meet and develop an efficient and responsive reporting mechanism for transmission adequacy. On August 15, 2000, CP&L, Duke, Dominion, NCEMC and the Public Staff met to discuss reporting on transmission adequacy. The utilities explained that transmission reliability is the subject of certain assessments and reports provided periodically by the utilities to the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the Department of Energy (DOE) and to the Southeastern Electric Reliability Council (SERC). The parties agreed that the utilities shall provide copies of the published reports to the Public Staff. After the Public Staff reviews the reports, the parties will have additional meetings, as necessary, in an effort to resolve this issue.

CP&L has agreed to provide to the Public Staff, on behalf of CP&L, Duke, Dominion, and NCEMC, copies of the following reports:

VST 2003 Summer Study
VACAR 2003 Reliability Study
1999 SERC Reliability Review Subcommittee Report
2000 Summer VAST Reliability Study
2000 Summer VEM Reliability Assessment
Each company's FERC Form 715 Filings from April, 2000.

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT

The incremental load (demand) for which customers are receiving credits under the economic development rates and/or self-generation deferral rates (Rider EC) is:

48MW For North Carolina
29MW For South Carolina

ANNUAL PLAN INFORMATION CONTENTS

1. LOAD FORECAST AND LOAD CAPACITY AND RESERVES (LCR) TABLE

This section includes a tabulation of summer and winter peak loads, annual energy forecast, generating capability, and reserve margins for each year, and a description of the methods and assumptions used to prepare the forecast.

THE LOAD FORECAST:

To determine customer energy needs, Duke prepares a load forecast of energy sales and peak demand using state-of-the-art econometric methodologies. The current forecast includes plans for the energy needs of all new and existing customers within Duke's service territory. This requirement may change in any restructured electric industry. Currently, certain wholesale customers have the option of obtaining all or a portion of their future energy needs from suppliers other than Duke Power.

As part of the joint ownership arrangement for the Catawba Nuclear Station, the North Carolina Electric Membership Cooperative (NCEMC), the Saluda River Electric Cooperative Incorporated (SR) and the North Carolina Municipal Power Agency #1 (NCMPA) have given notice that they will be solely responsible for their total load requirements beginning January 1, 2001. As a result, NCEMC, SR and NCMPA supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2001. Likewise, Piedmont Municipal Power Agency (PMPA) has given notice that they will be solely responsible for their total load requirements beginning January 1, 2006. As a result, PMPA supplemental load requirements, above their ownership portions of the Catawba Nuclear Station, are not reflected in the forecast commencing in 2006.

The current forecast over a 15-year period reflects an average annual growth in summer peak demand of 1.6 percent. Winter peaks are forecasted to grow at an average annual rate of 1.2 percent, and the average annual territorial energy is forecasted to grow at 1.8 percent. The growth rates use 2000 as the base year with 18,693 MW summer peak, 16,485 MW winter peak, and 98,016 GWH average annual territorial energy.

YEAR[4,5]	SUMMER (MW)[1]	WINTER (MW)[2]	TERRITORIAL ENERGY (GWH)[3]
2001	18,335	16,241	98,568
2002	18,737	16,162	100,962
2003	19,122	16,399	103,230
2004	19,543	16,658	105,507
2005	19,951	16,934	107,758
2006	20,156	17,160	109,704
2007	20,540	17,431	111,913
2008	20,946	17,711	114,093
2009	21,364	17,954	116,126
2010	21,761	18,256	118,338
2011	22,164	18,527	120,414
2012	22,574	18,777	122,397
2013	22,943	19,056	124,476
2014	23,330	19,327	126,477
2015	23,763	19,583	128,410

Note 1: Summer peak demand is for the calendar years indicated and includes the demand of the other joint owners of the Catawba Nuclear Station (CNS). Beginning on January 1, 2001 total demand above NCEMC, SR and NCMPA retained ownership is not included. Also, beginning on January 1, 2006 total demand above PMPA retained ownership is not included.

Note 2: Winter peak demand includes the demand of the other joint owners of the CNS. Beginning on January 1, 2001 total demand above NCEMC, SR and NCMPA retained ownership is not included. Also, beginning on January 1, 2006 total demand above PMPA retained ownership is not included.

Winter peak demand of 2001 is December 2000 which still includes the NCEMC, SR and NCMPA demand above their retained ownership. Winter peak demand of 2002 does not include NCEMC, SR and NCMPA demand above their retained ownership.

Note 3: Territorial energy is the total projected energy needs of the Duke service area, including losses and unbilled sales, and the energy requirements of the other joint owners of the CNS. Beginning on January 1, 2001 total energy above NCEMC, SR and NCMPA retained ownership is not included. Also, beginning on January 1, 2006 total energy above PMPA retained ownership is not included.

Note 4: This forecast is not comparable to that included in the 2000 Duke Power Forecast beginning January 1, 2001 due to removal of NCEMC, SR and NCMPA supplemental loads and beginning January 1, 2006 due to removal of PMPA supplemental loads.

Note 5: The impact of energy efficiency DSM programs is accounted for in the load forecast.

Seasonal Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2000 Annual Plan Base Case

W = WINTER, S = SUMMER	W 00/01	S 2001	W 01/02	S 2002	W 02/03	S 2003	W 03/04	S 2004	W 04/05	S 2005	W 05/06	S 2006	W 06/07	S 2007	W 07/08	S 2008
Forecast																
1 Duke System Peak	16,241	18,335	16,162	18,737	16,399	19,122	16,658	19,543	16,934	19,951	17,160	20,156	17,431	20,540	17,711	20,946
Cumulative System Capacity																
2 Generating Capacity	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,267	19,200	19,147	19,080	19,147
3 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	(90)	0	(120)	0	0	0
4 Cumulative Generating Capacity	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,290	19,357	19,200	19,267	19,080	19,147	19,080	19,147
5 Cumulative Purchase Contracts	1,144	1,243	993	993	993	993	341	341	341	331	121	121	121	121	121	121
6 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions																
Peaking/Intermediate	0	0	0	600	0	1,070	0	2,245	0	2,735	200	3,379	644	3,865	1,130	4,347
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,434	20,600	20,283	20,950	20,283	21,420	19,631	21,943	19,631	22,423	19,521	22,767	19,845	23,133	20,331	23,615
Reserves w/o DSM																
9 Generating Reserves	4,193	2,265	4,121	2,213	3,884	2,298	2,973	2,400	2,697	2,472	2,361	2,611	2,414	2,593	2,620	2,669
10 % Reserve Margin	25.8%	12.4%	25.5%	11.8%	23.7%	12.0%	17.8%	12.3%	15.9%	12.4%	13.8%	13.0%	13.8%	12.6%	14.8%	12.7%
11 % Capacity Margin	20.5%	11.0%	20.3%	10.6%	19.1%	10.7%	15.1%	10.9%	13.7%	11.0%	12.1%	11.5%	12.2%	11.2%	12.9%	11.3%
DSM																
12 Cumulative DSM Capacity	566	1,003	564	980	562	959	560	940	559	920	557	900	556	882	555	862
13 Cumulative Equivalent Capacity	21,000	21,603	20,847	21,930	20,845	22,379	20,191	22,883	20,190	23,343	20,078	23,667	20,401	24,015	20,886	24,477
Reserves w/DSM																
14 Equivalent Reserves	4,759	3,268	4,685	3,193	4,446	3,257	3,533	3,340	3,256	3,392	2,918	3,511	2,970	3,475	3,175	3,531
15 % Reserve Margin	29.3%	17.8%	29.0%	17.0%	27.1%	17.0%	21.2%	17.1%	19.2%	17.0%	17.0%	17.4%	17.0%	16.9%	17.9%	16.9%
16 % Capacity Margin	22.7%	15.1%	22.5%	14.6%	21.3%	14.6%	17.5%	14.6%	16.1%	14.5%	14.5%	14.8%	14.6%	14.5%	15.2%	14.4%

W = WINTER, S = SUMMER	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	08/09	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015
Forecast														
1 Duke System Peak	17,954	21,364	18,256	21,761	18,527	22,164	18,777	22,574	19,056	22,943	19,327	23,330	19,583	23,763
Cumulative System Capacity														
2 Generating Capacity	19,080	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,773
3 Capacity Retirements	(266)	0	0	0	0	0	0	0	0	0	0	0	(108)	0
4 Cumulative Generating Capacity	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,814	18,881	18,706	18,773
5 Cumulative Purchase Contracts	121	121	121	121	121	121	121	121	121	121	33	33	33	33
6 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Cumulative Future Resource Additions														
Peaking/Intermediate	1,612	5,157	2,422	5,643	2,908	6,125	3,390	6,611	3,876	7,093	4,358	7,575	4,840	8,223
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Production Capacity	20,547	24,159	21,357	24,645	21,843	25,127	22,325	25,613	22,811	26,095	23,205	26,489	23,579	27,029
Reserves w/o DSM														
9 Generating Reserves	2,593	2,795	3,101	2,884	3,316	2,963	3,548	3,039	3,756	3,152	3,878	3,159	3,996	3,266
10 % Reserve Margin	14.4%	13.1%	17.0%	13.3%	17.9%	13.4%	18.9%	13.5%	19.7%	13.7%	20.1%	13.5%	20.4%	13.7%
11 % Capacity Margin	12.6%	11.6%	14.5%	11.7%	15.2%	11.8%	15.9%	11.9%	16.5%	12.1%	16.7%	11.9%	16.9%	12.1%
DSM														
12 Cumulative DSM Capacity	554	845	554	828	554	811	553	794	553	778	554	763	555	749
13 Cumulative Equivalent Capacity	21,101	25,004	21,911	25,473	22,397	25,938	22,878	26,407	23,364	26,873	23,759	27,252	24,134	27,778
Reserves w/DSM														
14 Equivalent Reserves	3,147	3,640	3,655	3,712	3,870	3,774	4,101	3,833	4,309	3,930	4,432	3,922	4,551	4,015
15 % Reserve Margin	17.5%	17.0%	20.0%	17.1%	20.9%	17.0%	21.8%	17.0%	22.6%	17.1%	22.9%	16.8%	23.2%	16.9%
16 % Capacity Margin	14.9%	14.6%	16.7%	14.6%	17.3%	14.5%	17.9%	14.5%	18.4%	14.6%	18.7%	14.4%	18.9%	14.5%

The following notes are numbered to match the line numbers on the SEASONAL PROJECTIONS OF LOAD, CAPACITY, AND RESERVES table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Power August 3, 1998.

2. Generating Capacity. Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 100 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station (2258 MW).

   Capacity changes are due to Summer (May - Sept) Lincoln Fogger capacity of 67MW.

3. The 90 MW capacity retirement in 2006 represents the projected retirement date for CTs at Lee.
   The 120 MW capacity retirement in 2007 represents the projected retirement date for CTs at Riverbend.
   The 93 MW capacity retirement in 2009 represents the projected retirement date for the CTs at Buck.
   The 173 MW capacity retirement in 2009 represents the projected retirement date for CTs at Dan River & Bz Rst (Wst).
   The 108 MW capacity retirement in 2015 represents the projected retirement date for CT's at Buzzard Roost(GE).
   Oconee Nuclear Station is relicensed.
   All retirement dates are subject to review on an ongoing basis.

5. Purchase Contracts have several components:

   A. Effective January 1, 2001, the SEPA allocation will be reduced to 72MW. This reflects self scheduling by Seneca, Greenwood, Saluda River, NCEMC, and NCMPA1. The 72MW reflects allocations for PMPA and Schedule 10A customers who continue to be served by Duke.
   B. Piedmont Municipal Power Agency has given notice that they will be solely responsible for total load requirements beginning January 1, 2006. This reduces the SEPA allocation to 13 MW, which is attributed to Schedule 10A customers who continue to be served by Duke.
   C. Purchase of 250 MW maximum summer peak capacity from PECO began in June 1998 and expires Sept. 2001.
   D. Cogeneration megawatts have increased due to the 88 MW Cherokee Cogen contract which began in June 1998 and expires June 2013, and an additional 10 MW due to the firm purchase contract with the Kannapolis Energy Partners signed February 2000 and expires February 2005. The RJReynold's contract for 52MW expires December 31, 2003.
   E. Purchase of 302 MW summer peak capacity from July 1, 2000 to May 31, 2001 from CP&L, and 151 MW from June 1, 2001 to December 31, 2005.
   F. Purchase of 600 MW from Dynegy began July 1, 2000 and expires December 31, 2003.

7. Future Resource Additions represent new capacity resources or capability increases which are being considered. Neither the date of operation, the type of resource, nor the size is firm. All Future Resource Additions are uncommitted and represent capacity required to maintain a minimum planning reserve margin.

10. Reserve margin is shown for reference only.
    Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

11. Capacity margin is the industry standard term. A 14.6 percent capacity margin is equivalent to a 17.0 percent reserve margin.
    Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

12. Cumulative Interruptible and Direct Load Control capacity represents the demand-side management contribution toward meeting the load. The programs reflected in these numbers include dispatchable load control programs designed to be activated during capacity problem situations.

2. EXISTING PLANTS IN SERVICE

This section includes a list of the existing plants in service with capacity, plant type, and location.

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
Allen	1	165	Belmont, N. C.	Fossil
Allen	2	165	Belmont, N. C.	Fossil
Allen	3	265	Belmont, N. C.	Fossil
Allen	4	275	Belmont, N. C.	Fossil
Allen	5	270	Belmont, N. C.	Fossil
Belews Creek	1	1120	Walnut Cove, N. C.	Fossil
Belews Creek	2	1120	Walnut Cove, N. C.	Fossil
Buck	3	75	Spencer, N. C.	Fossil
Buck	4	38	Spencer, N. C.	Fossil
Buck	5	128	Spencer, N. C.	Fossil
Buck	6	128	Spencer, N. C.	Fossil
Buck	7C	31	Spencer, N. C.	Combustion Turbine
Buck	8C	31	Spencer, N. C.	Combustion Turbine
Buck	9C	31	Spencer, N. C.	Combustion Turbine
Buzzard Roost	6C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	7C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	8C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	9C	22	Chappels, S. C.	Combustion Turbine
Buzzard Roost	10C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	11C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	12C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	13C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	14C	18	Chappels, S. C.	Combustion Turbine
Buzzard Roost	15C	18	Chappels, S. C.	Combustion Turbine
Cliffside	1	38	Cliffside, N. C.	Fossil
Cliffside	2	38	Cliffside, N. C.	Fossil
Cliffside	3	61	Cliffside, N. C.	Fossil
Cliffside	4	61	Cliffside, N. C.	Fossil
Cliffside	5	562	Cliffside, N. C.	Fossil
Dan River	1	67	Eden, N. C.	Fossil
Dan River	2	67	Eden, N. C.	Fossil
Dan River	3	142	Eden, N. C.	Fossil
Dan River	4C	30	Eden, N. C.	Combustion Turbine
Dan River	5C	30	Eden, N. C.	Combustion Turbine
Dan River	6C	25	Eden, N. C.	Combustion Turbine
Lee	1	100	Pelzer, S. C.	Fossil
Lee	2	100	Pelzer, S. C.	Fossil
Lee	3	170	Pelzer, S. C.	Fossil
Lee	4C	30	Pelzer, S. C.	Combustion Turbine
Lee	5C	30	Pelzer, S. C.	Combustion Turbine
Lee	6C	30	Pelzer, S. C.	Combustion Turbine

Continued

EXISTING PLANTS IN SERVICE, continued

NAME	UNIT #	MW CAPACITY	LOCATION	PLANT TYPE
Lincoln	1	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	2	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	3	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	4	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	5	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	6	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	7	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	8	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	9	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	10	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	11	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	12	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	13	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	14	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	15	79.19	Lowesville, N. C.	Combustion Turbine
Lincoln	16	79.19	Lowesville, N. C.	Combustion Turbine
Marshall	1	385	Terrell, N. C.	Fossil
Marshall	2	385	Terrell, N. C.	Fossil
Marshall	3	660	Terrell, N. C.	Fossil
Marshall	4	660	Terrell, N. C.	Fossil
Riverbend	4	94	Mt. Holly, N. C.	Fossil
Riverbend	5	94	Mt. Holly, N. C.	Fossil
Riverbend	6	133	Mt. Holly, N. C.	Fossil
Riverbend	7	133	Mt. Holly, N. C.	Fossil
Riverbend	8C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	9C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	10C	30	Mt. Holly, N. C.	Combustion Turbine
Riverbend	11C	30	Mt. Holly, N. C.	Combustion Turbine
Catawba	1	1129	Clover, S. C.	Nuclear
Catawba	2	1129	Clover, S. C.	Nuclear
McGuire	1	1100	Cornelius, N. C.	Nuclear
McGuire	2	1100	Cornelius, N. C.	Nuclear
Oconee	1	846	Seneca, S. C.	Nuclear
Oconee	2	846	Seneca, S. C.	Nuclear
Oconee	3	846	Seneca, S. C.	Nuclear
Jocassee	1	152.5	Salem, S. C.	Pumped Storage
Jocassee	2	152.5	Salem, S. C.	Pumped Storage
Jocassee	3	152.5	Salem, S. C.	Pumped Storage
Jocassee	4	152.5	Salem, S. C.	Pumped Storage
Bad Creek	1	266.25	Salem, S. C.	Pumped Storage
Bad Creek	2	266.25	Salem, S. C.	Pumped Storage
Bad Creek	3	266.25	Salem, S. C.	Pumped Storage
Bad Creek	4	266.25	Salem, S. C.	Pumped Storage
Hydro (in various locations)		1136		Hydro

3. GENERATING UNITS UNDER CONSTRUCTION OR PLANNED

A list of generating units under construction or planned at plant locations for which property has been acquired, for which certificates have been received, or for which applications have been filed with location, capacity, plant type, and proposed date of operation included.

Duke has no generating units under construction or planned.

4. PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

This section includes a list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known.

The following table contains the recommended resource additions for maintaining the current minimum planning reserve margin through 2015. Neither the resource, date of operation, type, nor size is firm. Additionally, new resources may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting to build new generation.

CAPACITY[1] (MW)	SUPPLY SIDE RESOURCES	DATES OF OPERATION
600	Peaking/Intermediate	06/01/2002
470	Peaking/Intermediate	06/01/2003
1175	Peaking/Intermediate	06/01/2004
490	Peaking/Intermediate	06/01/2005
644	Peaking/Intermediate	06/01/2006
486	Peaking/Intermediate	06/01/2007
482	Peaking/Intermediate	06/01/2008
810	Peaking/Intermediate	06/01/2009
486	Peaking/Intermediate	06/01/2010
482	Peaking/Intermediate	06/01/2011
486	Peaking/Intermediate	06/01/2012
482	Peaking/Intermediate	06/01/2013
482	Peaking/Intermediate	06/01/2014
648	Peaking/Intermediate	06/01/2015

Note 1: Capacity amounts placed in service may vary due to selection of actual purchase amounts, generation technology capacity ratings, etc.

Note 2: Duke is currently evaluating responses to its Request For Proposal (RFP) issued January 5, 2000. Potential outcomes could include self build resources, purchased power resources, or a combination of both. In early 2001, Duke may issue another RFP for resource additions.

5. GENERATING UNITS PROJECTED TO BE RETIRED

This section includes a list of units projected to be retired from service with location, capacity and expected date of retirement from the system. The following table reflects decision dates for retirements or refurbishments during the planning horizon and are subject to review on an ongoing basis.

STATION	CAPACITY IN MW	LOCATION	DECISION DATE
Lee 4C	30	Pelzer, SC	12/31/2005
Lee 5C	30	Pelzer, SC	12/31/2005
Lee 6C	30	Pelzer, SC	12/31/2005
Riverbend 8C	30	Mt. Holly, NC	12/31/2006
Riverbend 9C	30	Mt. Holly, NC	12/31/2006
Riverbend 10C	30	Mt. Holly, NC	12/31/2006
Riverbend 11C	30	Mt. Holly, NC	12/31/2006
Buck 7C	31	Spencer, NC	12/31/2008
Buck 8C	31	Spencer, NC	12/31/2008
Buck 9C	31	Spencer, NC	12/31/2008
Buzzard Roost 6C	22	Chappels, SC	12/31/2008
Buzzard Roost 7C	22	Chappels, SC	12/31/2008
Buzzard Roost 8C	22	Chappels, SC	12/31/2008
Buzzard Roost 9C	22	Chappels, SC	12/31/2008
Dan River 4C	30	Eden, NC	12/31/2008
Dan River 5C	30	Eden, NC	12/31/2008
Dan River 6C	25	Eden, NC	12/31/2008
Buzzard Roost 10C	18	Chappels, SC	12/31/2014
Buzzard Roost 11C	18	Chappels, SC	12/31/2014
Buzzard Roost 12C	18	Chappels, SC	12/31/2014
Buzzard Roost 13C	18	Chappels, SC	12/31/2014
Buzzard Roost 14C	18	Chappels, SC	12/31/2014
Buzzard Roost 15C	18	Chappels, SC	12/31/2014

6. GENERATING UNITS WITH PLANS FOR LIFE EXTENSION

This section includes a list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed.

STATION	ORIGINAL LICENSE EXPIRATION DATE	REVISED LICENSE EXPIRATION DATE
OCONEE 1	2/2013	2/2033
OCONEE 2	10/2013	10/2033
OCONEE 3	7/2014	7/2034

On May 23,2000, the Nuclear Regulatory Commission approved the License Renewal for all three units of the Oconee Nuclear Station located near Seneca, South Carolina. With renewal, the original 40 year licenses for the three units has been extended for 20 years. The 20 year extension moves the license expiration dates from 2013 for Units 1 and 2 and 2014 for Unit 3 to 2033 and 2034, respectively. Maintenance work is normally performed during regularly scheduled refueling outages. No capacity upgrades of the units are currently being planned.

STATION	PRESENT LICENSE EXPIRATION DATE	PROPOSED LICENSE EXPIRATION DATE
McGuire 1	6/12/2021	6/12/2041
McGuire 2	3/3/2023	3/3/2043
Catawba 1	12/6/2024	12/6/2044
Catawba 2	2/24/2026	2/24/2046

In 2001, Duke Energy plans to submit an application to the Nuclear Regulatory Commission for license renewal of four additional units. The two units at McGuire Nuclear Station located near Huntersville, North Carolina and the two units at Catawba Nuclear Station located near Clover, South Carolina. With renewal, the original 40 year licenses for the four units will be extended for 20 years. The 20 year extension moves the license expiration dates from 2021 for McGuire Unit 1 and 2023 for McGuire Unit 2 to 2041 and 2043, respectively. In addition, the 20 year extension moves the license expiration dates from 2024 for Catawba Unit 1 and 2026 for Catawba Unit 2 to 2044 and 2046, respectively. Maintenance work is normally performed during regularly scheduled refueling outages. No capacity upgrades of the units are currently being planned.

7. TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES UNDER CONSTRUCTION

This section includes a list of transmission lines and other associated facilities (161 KV or over) which are under construction or for which there are specific plans including the capacity and voltage levels, location, and schedules for completion and operation.

The following table identifies construction of one connection station for a project in Duke's transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
Carolina Power & Light – New generation (~800MW)	500 kV	Guardian line–new connection station between McGuire Nuclear Station & Pleasant Garden, ~ 29 miles from McGuire (Rowan County)	Single circuit McGuire to CP&L to Pleasant Garden – 1666 MVA (No Upgrade)	June 1, 2001

In addition, NCUC Rule R8-62(p) requires the following information for existing transmission lines:

(1) For existing lines, the information required on FERC Form 1 pages 422, 423, 424, and 425.

Please see Appendix B for Duke's 1999 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 422.3, 423.3, 424 and 425.

(2) For lines under construction, the following:

a. commission docket number;
b. location of end point(s);
c. length;
d. range of right-of-way width;
e. range of tower heights;
f. number of circuits;
g. operating voltage;
h. design capacity;
i. date construction started;
j. projected in-service date.

Duke has no new transmission lines under construction.

(3) For all other proposed lines, as the information becomes available, the following:

a. county location of end point(s);
b. approximate length;
c. typical right-of-way width for proposed type of line;
d. typical tower height for proposed type of line;
e. number of circuits;
f. operating voltage;
g. design capacity;
h. estimated date for starting construction;
i. estimated in-service date.

Duke has no proposed new transmission lines.

8. GENERATION OR TRANSMISSION LINES SUBJECT TO CONSTRUCTION DELAYS

This section includes a list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the Commission Staff, the reporting utility shall supply a statement of the economic impact of such delays.

There are no delays over six months in the stated in-service dates.

9. DEMAND-SIDE OPTIONS AND SUPPLY-SIDE OPTIONS REFLECTED IN THE PLAN

This section includes a list of demand-side options and supply-side options reflected in the resource plan.

ENERGY EFFICIENCY DEMAND-SIDE OPTIONS:

All effects of existing energy efficiency DSM programs listed below are captured in the customer load forecast:

RESIDENTIAL SERVICE WATER HEATING - CONTROLLED/SUBMETERED

This program shifts a participating customer's water heating usage to off peak periods as determined by Duke. The program is currently available in accordance with rate Schedule WC. The customer is billed at a lower rate for all water heating energy consumption in exchange for allowing Duke to control the water heater.

EXISTING RESIDENTIAL HOUSING PROGRAM

This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures. The program consists of loans for heat pumps, central air conditioning systems, and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

In the past year, Duke reviewed two energy efficiency pilot programs:

Special Needs Energy Products Loan
Neighborhood Revitalization Program

The pilots were combined into one program, Special Needs Energy Products Loan Program, effective February 24, 2000. This residential program represents Duke's activities in the existing residential market to encourage increased energy efficiency in existing residential structures for low income customers. The program consists of loans for heat pumps, central air conditioning systems, and energy efficiency measures such as insulation, HVAC tune-up, duct sealant, etc.

INTERRUPTIBLE DEMAND-SIDE OPTIONS:

These existing interruptible DSM options are identified on line 12 of the Seasonal Projections of Load, Capacity, and Reserves table. The interruptible DSM Options are not included in the customer load forecast because load control contribution depends upon actuation.

RESIDENTIAL LOAD CONTROL

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems. For air conditioning control, participants receive billing credits during the billing months of July through October for allowing Duke to interrupt electric service to their central air conditioning systems. For water heating control, participants receive billing credits each month for allowing Duke to interrupt electric service to their water heaters. Water heating load control was closed to new customers on January 1, 1993 in North Carolina and on February 17, 1993 in South Carolina.

STANDBY GENERATOR CONTROL

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to transfer electrical loads from the Duke source to their standby generators when so requested by Duke. The generators in this program do not operate in parallel with Duke's system and, therefore, cannot "backfeed" (or export power) into the Duke system. Participating customers receive payments for capacity and/or energy based on the amount of capacity and/or energy transferred to their generator.

INTERRUPTIBLE POWER SERVICE

This program is designed to provide a source of interruptible capacity to Duke at any time it encounters capacity problems during the year. Participants in the program contractually agree to reduce their electrical loads to specified levels when so requested by Duke. Failure to do so results in a penalty for the increment of demand which exceeds a specified level. The program has not been available to new participants since 1992.

Projected data on the Interruptible DSM Programs are contained on the following page.

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AC/LC	199,676	198,723	196,100	193,476	190,853	188,230	185,606	182,983	180,359	177,736	175,113	172,489	169,866	167,242	164,619	161,996
WH/LC	41,964	37,924	34,876	31,829	28,781	25,733	22,686	19,638	16,591	13,543	10,495	7,448	4,400	1,353	0	0
IS	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203
SG	140	142	144	146	148	150	152	154	156	158	160	162	164	166	168	170

Demand (kw)

	2000		2001		2002		2003		2004		2005		2006		2007	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	377,000	0	359,000	0	336,000	0	315,000	0	295,000	0	274,000	0	254,000	0	235,000
WH/LC	29,000	8,000	25,000	7,000	22,000	6,000	19,000	5,000	16,000	5,000	14,000	4,000	11,000	3,000	9,000	3,000
IS	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000
SG	70,000	84,000	71,000	85,000	72,000	86,000	73,000	87,000	74,000	88,000	75,000	90,000	76,000	91,000	77,000	92,000
Total	569,000	1,021,000	566,000	1,003,000	564,000	980,000	562,000	959,000	560,000	940,000	559,000	920,000	557,000	900,000	556,000	882,000

Demand (kw)

	2008		2009		2010		2011		2012		2013		2014		2015	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
AC/LC	0	215,000	0	197,000	0	179,000	0	161,000	0	144,000	0	127,000	0	111,000	0	95,000
WH/LC	7,000	2,000	5,000	2,000	4,000	1,000	3,000	1,000	1,000	0	0	0	0	0	0	0
IS	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000	470,000	552,000
SG	78,000	93,000	79,000	94,000	80,000	96,000	81,000	97,000	82,000	98,000	83,000	99,000	84,000	100,000	85,000	102,000
Total	555,000	862,000	554,000	845,000	554,000	828,000	554,000	811,000	553,000	794,000	553,000	778,000	554,000	763,000	555,000	749,000

Budget

	2000	2001	2002	2003	2004	2005
AC/LC	$6,443,000	$6,359,000	$6,275,000	$6,191,000	$6,107,000	$6,023,000
WH/LC	$983	$910	$837	$764	$691	$618
IS	$20,107,000	$20,107,000	$20,107,000	$20,107,000	$20,107,000	$20,107,000
SG	$2,340,000	$2,373,000	$2,407,000	$2,440,000	$2,473,000	$2,507,000
Total	$28,890,983	$28,839,910	$28,789,837	$28,738,764	$28,687,691	$28,637,618

Note: Only includes credits paid to customers.

Energy (kwh)	
AC/LC	None
WH/LC	None
IS	None
SG	None

Target Market Segment	
AC/LC	Residential
WH/LC	Residential
IS	Commercial & Industrial
SG	Commercial & Industrial

9. DEMAND-SIDE OPTIONS AND SUPPLY-SIDE OPTIONS REFLECTED IN THE PLAN, continued

The Supply-Side Options selected for the expansion plan are subjected to an economic screening process to determine cost effective supply side technologies. The most viable supply-side technologies are selected.

Viable Supply-Side Options:

Conventional Technologies: (technologies in common use)
162 MW Combustion Turbine
482 MW Combined Cycle
600 MW Conventional Fossil
400 MW Gas Fired Boiler
1600 MW Pumped Storage

Demonstrated Technologies: (technologies with limited acceptance and not in widespread use)
20 MW Lead Acid Battery
220 MW Compressed Air Energy Storage (CAES)

The most economically attractive technologies that were selected for expansion planning analysis were:

162 MW Combustion Turbine
482 MW Combined Cycle

10. WHOLESALE PURCHASE POWER COMMITMENTS REFLECTED IN THE PLAN

1. Rockingham L.L.C. has constructed a gas-fired, five-unit, 750 MW generation facility in Rockingham County, NC. Duke Power has a contract to purchase 600 megawatts of capacity and energy generated by the power plant. The contract term began July 1, 2000 and runs through the end of 2003, with options to extend through 2008.

2. Duke Power has acquired capacity purchase options of 250 MW from PECO Energy. The contract term began in June 1998 and will continue through September 2001. This contract is applicable during summer months only (June - September).

3. Duke Power has acquired capacity purchase contract of 302 MW from CP&L. The contract term begins July 1, 2000 to May 31, 2001 at 302 MW. The contract capacity then drops to 151 MW from June 1, 2001 to December 31, 2005.

4. Duke purchases 88 MW of capacity from Cherokee Cogeneration on an annual basis, through June 2013.

5. Duke expects to purchase approximately 82 MW annually from other cogeneration and small power producers as identified in Appendix C. These firm purchases will decrease over time as contracts expire.

11. WHOLESALE POWER SALES COMMITMENTS REFLECTED IN THE PLAN

Duke provides wholesale power sales under Schedule 10A. The load requirements of Schedule 10A customers are reflected in the Seasonal Projections of Load, Capacity and Reserves table. Sales in 1999 totaled 1347 GWH as reported in Duke Energy's 1999 FERC Form 1 filing.