<u>ATTACHMENT D</u>

Proposed Changes to Operating Licenses and Technical Specifications for Dresden Nuclear Power Station, Units 2 and 3

INFORMATION SUPPORTING AN ENVIRONMENTAL ASSESSMENT

In accordance with 10 CFR 51.21, "Criteria for and identification of licensing and regulatory actions requiring environmental assessments," Commonwealth Edison (ComEd) has prepared a supplement to the Dresden Nuclear Power Station (DNPS) environmental report to describe the environmental effects of the Extended Power Uprate (EPU) project. This report is attached.

ComEd has evaluated this proposed change against the criteria for identification of licensing and regulatory actions requiring environmental impact statements and has determined that these proposed changes do meet the requirements for an environmental impact statement set forth in 10 CFR 51.20, "Criteria for and identification of licensing and regulatory actions requiring environmental impact staements." As demonstrated in the attached report, there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite and there is no significant increase in individual or cumulative occupational radiation exposure.

Revision 2

Supplement to Environmental Report

Dresden Nuclear Power Station

Extended Power Uprate

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1.0 INTRODUCTION

ComEd, an Exelon Company, is committed to environmentally responsible business practices. ComEd utilizes proactive management strategies, leading-edge technologies, and voluntary actions to protect its shared environment and to preserve natural resources. This environmental stewardship is demonstrated by ComEd's respect for public health and the environment while providing safe, reliable, and economical service to its customers. ComEd relies upon a proactive environmental management organization that emphasizes alliances with surrounding communities and customers to conserve resources, promote renewable energy, restore habitat, and reduce pollution at its source (Ref. 1). In keeping with this commitment to environmental stewardship, ComEd has conducted a comprehensive environmental evaluation of the proposed Dresden Nuclear Power Station (DNPS) Extended Power Uprate (EPU) from 2,527 megawatts-thermal (MWt) to 2,957 MWt (i.e,. 809 megawatts-electrical [MWe] to 912 MWe) for both Unit 2 and Unit 3. The proposed uprate will service the future power requirements of the ComEd customer base, whose peak demand is estimated to increase by 28 percent from 2000 to 2014.

A prerequisite to the EPU at the DNPS is the preparation of an Environmental Assessment Report to assist the U.S. Nuclear Regulatory Commission (NRC) in deciding upon the issuance of operating license amendments for generating Units 2 and 3 (Ref. 2). 10 CFR 51.41, "Requirement to Submit Environmental Information," requires that applications to the NRC be in compliance with Section 102(2) of the National Environmental Policy Act (NEPA) and in accordance with the regulations for implementing the procedural provisions of NEPA (40 CFR 1500-1508). Environmental report general requirements are outlined in 10 CFR 51.45, "Environmental Report." There are no NRC regulatory requirements or guidance documents specific to preparation of environmental documentation for EPU applications. This report is intended to provide sufficient detail in this environmental assessment report regarding both radiological and non-radiological environmental impacts sufficient for the NRC to make an informed decision regarding the proposed action.

In November 1973, the U.S. Atomic Energy Commission (AEC), predecessor to the NRC, published the Final Environmental Statement (FES) on the operation of DNPS Units 2 and 3. The AEC/NRC concluded that issuance of a full-term operating license for Unit 2 and continuation of the operating license for Unit 3, subject to specified limitations for the protection of the environment, were the proper courses of action under NEPA. This decision was based on the analysis presented in the FES and the weight of environmental, economic, technical, and other benefits of the Station versus environmental costs and available alternatives. This environmental assessment report will address impacts of the EPU to the environment, compare changes to those presented in the FES or in more recent environmental reports, identify reasonable alternatives to the proposed EPU, and recommend the proper course of action.

2.0 PROPOSED ACTION AND NEED

ComEd operates DNPS at the headwaters of the Illinois River, downstream of the confluence of the Kankakee and Des Plaines Rivers. DNPS is a nuclear powered steam electric generating facility that consists of three boiling water reactors (BWR) (Ref. 2). Units 2 and 3 are the only generating units subject to the proposed EPU. Unit 1 was a first generation turnkey demonstration plant, with turbine tests forming the basis for design of larger BWR turbines. Unit 1 was the first full-scale privately financed nuclear power plant in the United States and operated from November 1959 until October 1978. In 1984, Unit 1 decontamination was completed and the unit is currently shut down and awaiting decommissioning. In 1991, the American Nuclear Society designated DNPS Unit 1 as a Nuclear Historic Landmark (Ref. 3).

DNPS is located in Goose Lake Township, Grundy County, Illinois, approximately 50 miles southwest of downtown Chicago and approximately 8 miles east of the city of Morris, Illinois. The station (Figure 2-1) is situated on approximately 2,500 acres of land owned by ComEd and contains the station, approximately two miles of cooling canals, and a 1,275-acre cooling pond. DNPS Unit 2 received its construction permit on January 10, 1966 and its Operating License No. DPR-19 on December 22, 1969. DNPS Unit 3 received its construction permit on October 14, 1966, and its Operating License No. DPR-25 on January 12, 1971 (Ref. 4).

Water heated by DNPS Units 2 and 3 is cooled using a heat dissipation system consisting of a cooling pond, cooling canals, and mechanical draft cooling towers. The cooling system for Units 2 and 3 can be used for two modes of operation: indirect open cycle and closed cycle. Pursuant to the National Pollutant Discharge Elimination System (NPDES) permit, DNPS may operate in indirect open cycle mode from June 15 through September 30. Closed cycle operation is permitted at any time (Ref. 5). DNPS is also permitted to use a variable cooling water discharge plan from June 1 to June 15. Under this plan, when the cooling water temperature entering the condenser exceeds 91.5 degrees Fahrenheit (°F), DNPS may increase the flow of water from the Kankakee River added to the cooling pond return flow to keep the condenser inlet temperature from exceeding 91.5 °F. Section 3.2, "Non-Radiological Environmental Impacts," has greater detail on the hydrologic effects of indirect open cycle and closed cycle operations.

The DNPS Units 2 and 3 BWRs operate in a direct thermodynamic cycle between the reactor and the turbine. EPU will increase the heat output of the reactors to support increased inlet steam flow to the turbines. To support an EPU from 2,527 MWt to 2,957 MWt, the reactor core operating range will be expanded by increasing reactor power using a plant performance improvement program known as MELLL/ARTS (Maximum Extended Load Line Limit/APRM [Average Power Range Monitor], RBM [Rod Block Monitor], and Technical Specification changes). No changes in operating pressure or core flow are necessary to

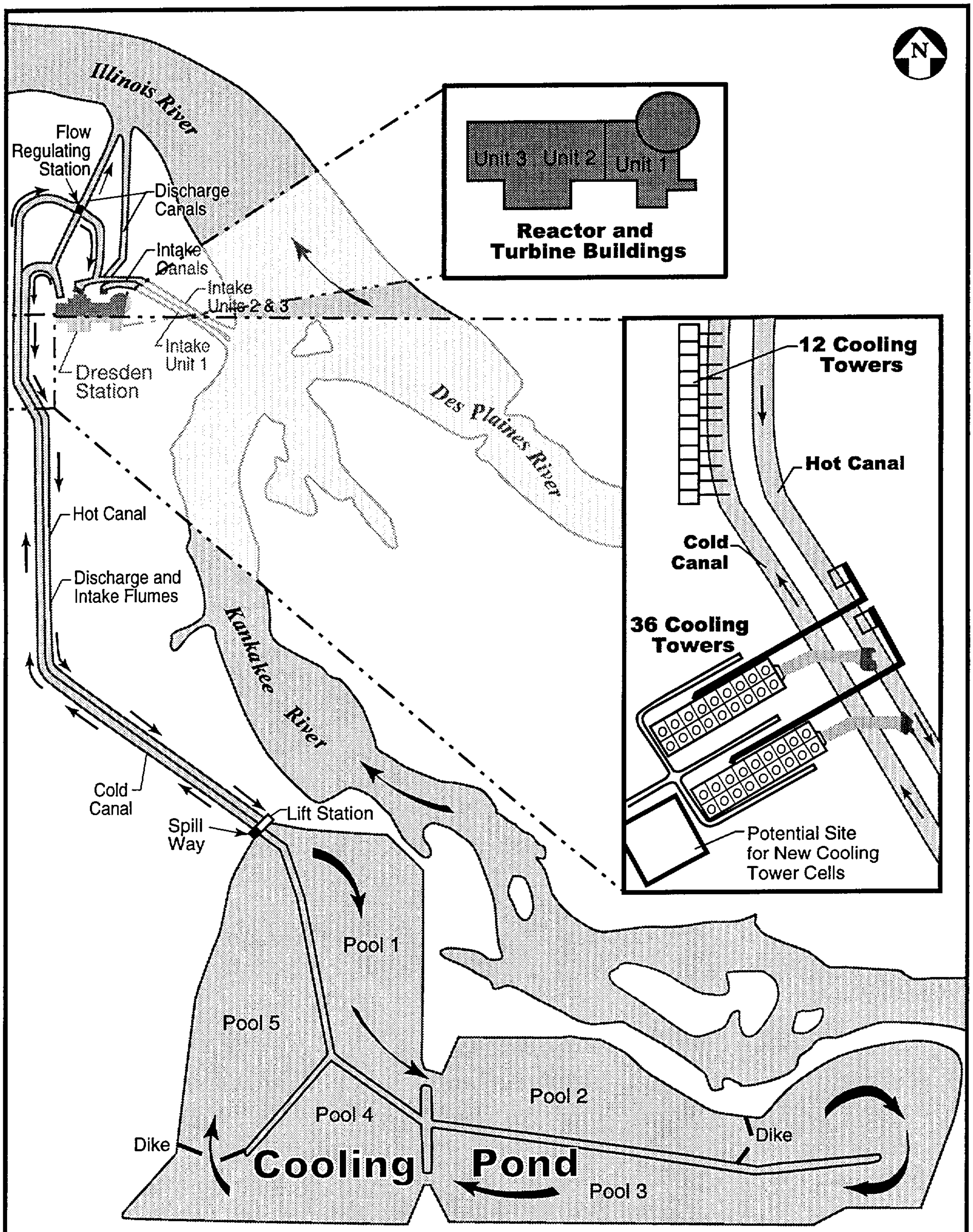

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Figure 2-1. A schematic description of the Dresden Nuclear Power Station cooling water systems.

support the EPU. Environmental impacts from these operational changes are discussed in Chapter 3.

Due to the design and safety margins built into plant equipment, the proposed EPU operational changes described above can be accomplished with relatively few plant modifications. The most significant changes will involve replacing the high-pressure turbines on both units, installing additional cooling towers, and installing condensate prefiltration vessels. The modifications will be accomplished by normal maintenance and modification procedures, similar to those performed during normal outages. The majority of plant systems will not require any significant modifications.

2.1 Description of Proposed Action

ComEd has established the goal of increasing the electrical generating capacity in a cost-effective and environmentally sound manner. Therefore, ComEd and the station designer, General Electric, have comprehensively evaluated the effects of an EPU at DNPS Units 2 and 3. This evaluation concluded that safety and design margins are sufficient to allow an increase in the rated core thermal power from 2,527 MWt to 2,957 MWt without adversely impacting the safety of the public and without significantly impacting the environment. Therefore, the action proposed is to amend the DNPS Units 2 and 3 operating licenses and supporting technical specifications to allow for an increase in the licensed core thermal power level to 2,957 MWt.

2.2 Need for Proposed Action

ComEd forecasts a 28 percent increase in electrical demand by 2014 within its traditional Illinois service area. A plan has been prepared for the period from 2000 through 2014 to evaluate resource needs. Completion of EPU on the first generating unit will increase the ComEd generating capacity by approximately 0.66 percent. When EPU is completed on the second generating unit, another similar increase in system generating capacity is forecast. Uprating generating capacity at DNPS is more economical for ComEd than constructing new generating capacity. Also see Section 4.0 for a detailed discussion of alternatives to the proposed action.

The ComEd service area is part of the Mid-America Interconnected Network (MAIN) North American Electric Reliability Council (NERC) region. The MAIN NERC has forecast adequate generating capacity of participating utilities over the next five years. However, in the coming deregulated marketplace, the traditional ComEd service area will be served by ComEd as well as by new market companies. To continue reliable, cost-effective service, ComEd must fulfill customer power demands while also marketing power to other providers. In Illinois, other power providers have proposed and/or begun construction of approximately 40 gas turbine "peaker" plants of various sizes in anticipation of the increase in demand and the deregulated marketplace (Ref. 6). In this deregulated arena, the proposed EPU will displace approximately two 100 MWe gas turbines.

3.0 ENVIRONMENTAL IMPACTS

3.1 Socioeconomic Considerations

The proposed EPU does not significantly affect the size of the DNPS work force and does not have a material effect on the labor force required for future plant outages. During 2000, the DNPS employed 872 full-time staff and 122 contract personnel, for a total of 994 employees. Over 95 percent of the employees resided within seven counties in Illinois with over 72 percent residing in Grundy and Will Counties. During 2000, the annual average ComEd employee salary was $67,000 and the average contractor's salary was $60,000. The average wage per job in Grundy County during 1998 was $34,557 (Ref. 7). Therefore, DNPS workers have a disproportionate, but positive, influence on the economies of the region due to their higher incomes.

Material and labor costs for equipment required to implement the EPU at the DNPS are approximately $26 million. Local taxing authorities will experience an increase in property tax bases and significant positive economic benefits will be realized by the local and national businesses participating in this proposed EPU. In addition, engineering and consulting firms, equipment suppliers, and service industries will receive payments for EPU activities. The direct revenue associated with EPU installation will not be sustained once modifications are complete. However, the economic benefits associated with the EPU will represent a positive impact on the local economy, both in terms of the one-time benefit of EPU installation and in the long-term viability of operating the DNPS.

The assessed value of the DNPS has increased since construction was completed. Table 3-1 presents the equalized assessed valuation of the station for 1990, 1995, and 1999. The assessed value has increased approximately $122 million over this time period, resulting in additional revenues for the local taxing authorities (Table 3-2). Communities surrounding the DNPS have benefited and would continue to benefit from local taxes paid by ComEd. Public services, including law enforcement, fire protection, public education, and health services, receive a significant amount of economic support through these tax revenues.

Table 3-1. Equalized Assessed Valuation for the Dresden Nuclear Power Station, Units 2 and 3 for 1990, 1995, and 1999.

	1990	**1995**	**1999**
Equalized Assessed Value	$170,002,000	$268,971,370	$292,082,540

Table 3-2. Taxes paid by Commonwealth Edison for the Dresden Nuclear Power Station, Units 2 and 3 for tax years 1995 through 1999

Tax Year	Property Tax Payment
1995	$10,790,055
1996	$11,137,696
1997	$11,910,726
1998	$12,182,857
1999	$12,729,833

The socioeconomic effects of implementing EPU at the DNPS are, in part, dependent on the ability of ComEd to remain competitive in a market that is being deregulated. Implementation of EPU is not the primary factor affecting the overall competitiveness of ComEd, but it is a factor that must be considered. ComEd has determined that, notwithstanding the uncertainty associated with deregulation, the favorable capital cost of the proposed EPU compared to new generating capacity, and the reduction in incremental operating costs that result from EPU, make the EPU project attractive. In addition, the investment associated with the proposed EPU will result in increased revenues, thus enhancing the value of the DNPS as a provider of electricity.

3.2 Non-Radiological Environmental Impacts

- Terrestrial Resources Effects

Land Use

Approval of the proposed EPU would result in some minor modifications to current land use at DNPS. These changes are associated with the addition of six to eight new mechanical draft cooling tower cells to the 48 existing cells (Ref. 8 and Ref. 9). Also, due to a small increase in the number of fuel assemblies used in each cycle, the current DNPS plans for dry cask storage may be increased to add an additional storage pad with an area of less than one-tenth acre.

The new cooling tower cells will require approximately 0.5 acre. Other cooling tower impacts such as access roads and pipe bridge installation may require additional disturbance, although this impact should be less than the footprint of the cooling tower cells. The location of the new cells is in an area that has been previously disturbed (Figure 2-1). ComEd is evaluating the engineering requirements of the siting options within this general area.

Activities over the period of construction could displace small numbers of animals (e.g., songbirds and small mammals) that forage, feed, nest, or rest in the area. These construction-related impacts would be small, intermittent, and localized. Some animals could choose to leave the area permanently, while others could become accustomed to the increased noise and activity and return to the area. Species likely to be affected (e.g., ground squirrel, rabbit, and songbirds) are common to these areas. Adding the cooling tower cells and the additional dry cask storage would not impact any historic or archaeological areas. However, there would be some minor changes to visual and aesthetic resources. The additional construction would not be visible from any major interstate highway or state highway, nor would it block the view of any historic sites or landscape vistas.

Implementation of the EPU would not affect storage requirements, in terms of land use, for above ground or below ground tanks. Construction of low-level radioactive waste storage is not needed to support EPU. No other land use changes besides those discussed above will be needed to support the EPU.

Terrestrial Biota

A study performed during the first three years of indirect open cycle operation concluded there were no adverse impacts noted on waterfowl or wildlife (Ref. 10). However, as noted in the FES, the presence of the DNPS cooling pond does provide an additional foraging and resting area for waterfowl and also provides nesting grounds in an area of the state where natural lakes are less abundant. Implementation of the EPU would not alter these conclusions.

There are no known threatened or endangered species existing within the area that would be impacted by land use changes associated with construction activities for the additional cooling towers. Certain threatened and endangered species (e.g., bald eagle) have been sighted and/or are likely to be in the vicinity of DNPS. Table 3-3 presents the seven Federally listed threatened and endangered species identified during 1999 in Grundy and Will Counties, Illinois (Ref. 11).

Operation of the 48 currently permitted mechanical-draft cooling towers has had no observed detrimental impact on the terrestrial community. Therefore, the addition of six to eight cooling tower cells, that will operate intermittently during periods of high ambient temperature, should not impact this resource.

No new solid waste streams or significant contributions to existing solid waste streams are expected from the EPU, other than a transient, short-term increase in waste volume associated with installation activities. This short-term volume increase may be slightly higher than solid waste volumes generated during normal outages.

Transmission Facilities

No changes in operating transmission voltages, onsite transmission equipment, or power line right-of-way are required to implement or

Table 3-3. Federally listed threatened and endangered species identified in Grundy and Will Counties, Illinois (Ref. 11).

Species	County	Status
Mead's Milkweed (*Asciepias meadii*)	Will	Threatened
Lakeside Daisy (*Hymenopsis herbacea*)	Will	Threatened
Leafy Prairie Clover (*Dalea foliosa*)	Will	Endangered
Eastern Prairie Fringed Orchid (*Platanthaera leucophaea*)	Grundy	Threatened
Hines Emerald Dragonfly (*Somatochlora hineana*)	Will	Endangered
Bald Eagle (*Haliaeetus leucocephalus*)	Grundy & Will	Threatened
Indiana Bat (*Myotis sodalis*)	Grundy & Will	Endangered

support this EPU. However, an increase in onsite power use will be required to support the new cooling tower cells and other new equipment associated with the EPU. Power to service these additional energy needs will come from the existing power supplies currently serving DNPS. Sufficient power is available to meet the needs of the new EPU equipment. There are no new requirements or modifications necessary for the offsite power system to maintain grid stability.

No changes in transmission facilities will be needed for the EPU. The electromagnetic field (EMF) created by transmission will be increased as an essentially linear function of power. After the EPU, power production at DNPS would be less than the capacity at other ComEd stations where no harmful effects from EMFs are known to have occurred.

Finally, implementation of the EPU does not increase the probability of shock from primary or secondary currents. Transmission lines are constructed to meet or exceed requirements of the Illinois Commerce Commission General Order 160, which is identical to the National Electric Safety Code (NESC).

Noise

Implementation of the EPU would result in intermittent increases in noise levels during periods of high ambient temperature, due to the operation of the new cooling tower cells and the potential extended operation of the existing cooling towers. Noise from cooling tower operations will be in compliance with all applicable noise requirements, including those found at 35 Illinois Administrative Code (IAC) Chapter I

Part 901, "Sound Emission Standards and Limitations for Property Line Noise Sources."

The cooling system discussed in the FES did not include any cooling towers, but did include 98 spray modules placed within the cooling canal prior to the water being pumped to the cooling pond, that resulted in elevated noise levels. The spray modules are no longer operated. Therefore, no significant, if any, increase in noise levels is expected to result from EPU beyond that which has been observed previously, and the FES conclusions regarding noise impacts remain valid.

Cooling Tower Drift, Icing, and Fog

Drift, icing, and fog from operation of the DNPS Units 2 and 3 cooling system were discussed in the FES and determined to be acceptable and not harmful to the surrounding environment. No substantial changes from the conditions reported in the FES are foreseen, although removal of the spray modules has mitigated some icing effects. The cooling towers currently operating at DNPS were installed in 1999 and 2000 and were sited in their present location to reduce potential fogging impacts on local roads, based on experience gained with the operation of 80 temporary, portable cooling tower modules in 1998 at DNPS. The cooling towers represent the state of the art in mechanical draft technology that minimize drift and maximize efficiency. Each cooling tower cell is equipped, operated, and maintained with drift eliminators designed to limit the loss of water droplets from the cell to not more than 0.008 percent of the circulating water flow (i.e., drift factor of 0.00008).

Fog formation occurs when the air temperature is sufficiently less than the cooling water temperature, which allows the air layer immediately above the water to become saturated. When the saturated air mixes with cooler surrounding air, condensation occurs, forming a fog. This condition only occurs when the temperature differential between ambient air and the cooling water is high. Typically, this happens during the cold season when the cooling towers are not likely to be operated. The proposed EPU will increase the temperature of the water in the hot canal by approximately 4.2 °F. This temperature increase is not expected to cause an observable increase in the intensity of fog, but because EPU increases the temperature differential between the cooling water and ambient air, fog may form at slightly higher ambient air temperatures.

Based on the analysis presented in the FES for the spray modules, the cooling canals and the cooling pond, the impacts from drift, icing, and fog from the proposed EPU are within impacts presented in the FES.

- Air Quality Effects

The cooling towers are permitted to operate by the Illinois Environmental Protection Agency (IEPA) issued Federally Enforceable State Operating Permit (FESOP) number 063806AAC as amended by

Construction Permit Application 99120062. The cooling towers emit particulate matter (PM_{10}) in the form of drift with river water sediment entrained in the droplets. The existing 48 cooling tower cells have a potential to emit 67.2 tons of PM_{10} per year. A maximum of eight additional cooling tower cells will have the potential to emit an additional 11.2 tons of PM_{10} per year, resulting in a total potential to emit of 78.4 tons of PM_{10} per year from the cooling towers. DNPS is in an attainment area for PM_{10} in which the major source threshold is 100 tons/year. Therefore, the total emissions from DNPS are significantly below the major source threshold for PM_{10}. Emissions from all other sources governed by the FESOP are expected to remain unchanged.

➢ Hydrology Effects

DNPS Units 2 and 3 both utilize a single-cycle forced-circulation BWR supplied by General Electric Company. Each reactor produces saturated steam for direct use in a separate steam turbine-generator unit. When steam leaves the turbine, it is condensed, demineralized, and pumped back to the reactor vessel. This system is closed and does not contact the water used to cool the condensers. Cooling water for the condensers is pumped from the Kankakee and Des Plaines Rivers. The original design called for a once-through, or open-cycle, cooling water system in which all the heated water was returned to the Illinois River downstream of the intake. However, a number of configuration changes have been made in the cooling system at DNPS since it was originally designed. These include the construction of a cooling pond and associated cooling canals, the installation of spray modules in the cooling canals, the installation of temporary mechanical draft cooling towers, and finally the construction of permanent mechanical draft cooling towers.

As stated in Section 2.0, DNPS operates in the indirect open cycle mode from June 15 through September 30. In this mode of operation, a maximum of 940,000 gallons per minute (gpm) may be withdrawn from the Kankakee and Des Plaines Rivers for condenser cooling water. After circulating through the condensers, water is discharged into a two-mile-long cooling canal (i.e., hot canal). As water travels through the hot canal, it may be withdrawn and circulated through a bank of 36 permitted (Ref. 8) mechanical draft cooling tower cells (Figure 2-1) and then discharged back into the hot canal. The hot canal cooling towers have a maximum water withdrawal capacity of 630,000 gpm. The water passes through the towers and returns to the hot canal at a cooler temperature. During this indirect open cycle mode, the cooling towers operate as necessary to maintain water temperatures within NPDES permit limits. From the hot canal, a lift station pumps cooling water into a 1,275-acre cooling pond. The cooling pond consists of five pools through which the cooling water is circulated for a mean retention time of approximately two and one half days, at full pumping capacity. After circulation through the cooling pond, the water is discharged via a spillway into another two-mile-long canal (i.e., cold canal) flanking the hot canal. Adjacent to the cold canal is a bank of 12 mechanical draft cooling tower cells (Figure 2-1). Water may be pumped from the cold canal at a maximum rate of approximately 213,000 gpm. The water is circulated through the cooling tower cells as necessary to maintain water temperatures within NPDES permit limits, and returned to the cold canal at a cooler temperature. The water is then discharged to the Illinois River (Ref. 5).

The other mode of plant operation is closed cycle. The station can operate in closed cycle at any time, but normally operates in this mode from October 1 through June 14 when the mechanical draft cooling towers are typically not utilized. In this mode, water is drawn into the intake structure, circulated through the condensers for Units 2 and 3, passed through the hot canal, the cooling pond, the cold canal then routed back to the intake structure via the flow regulating station gates (i.e., recirculated). A small portion of condenser cooling water (70,000 gpm) is withdrawn from the Kankakee and Des Plaines Rivers because of evaporative and seepage losses in the cooling pond. In order to prevent an increase in the dissolved solids concentrations in the cooling pond (which would impact condenser efficiency), approximately 50,000 gpm of the cooling water is permitted (Ref. 5) to be discharged (i.e. blown down) to the Illinois River.

DNPS has approval (Ref. 5) to allow the Grundy County Emergency Management Agency to operate a de-icing project on the Kankakee River using heated water from the DNPS cooling pond. Heated water from the cooling pond is transported through a permanent pipe by siphon to the Kankakee River where it is used to prevent river ice from damaging docks and other structures.

Implementation of the proposed EPU will not change the hydrodynamics of the condenser cooling water system intake and discharge amounts, therefore, no additional impacts are expected.

DNPS operates under NPDES Permit No. IL0002224 that covers the following discharges:

- 001 Unit 1 House Service Water (inactive)
- A01 Unit 1 intake Screen Backwash (inactive)
- 002 Cooling Pond Blowdown
- A02 Unit 2/3 Intake Screen Backwash
- B02 Wastewater Treatment System Effluent
- C02 Radiological Waste Treatment System Effluent
- D02 Demineralizer Regenerant Waste
- E02 North West Material Access Runoff
- 003 Sewage Treatment Plant Effluent
- 004 Cooling Pond Discharge
- 005 South East Area Runoff
- 006 North East Area Runoff

All of these discharges are to the Illinois River except 003, 004, 005, and 006, which discharge to the Kankakee River. The NPDES permit became effective November 1, 2000 (Ref. 5). Special Condition 4 of the permit gives thermal limitations at the edge of the mixing zone, including a maximum temperature rise of 5 °F above natural temperature and maximum temperature limits for each month of the year. DNPS must operate in closed cycle mode from October 1 to June 15 and may operate in indirect open cycle cooling mode from June 15 through September 30. During indirect open cycle operation, the temperature of the discharges cannot exceed 90 °F more than 10 percent of the time and can never exceed 93 °F. The station may also operate in accordance with the DNPS Units 2 and 3 Variable Blowdown Plan, as governed by the original July 6, 1977, Thermal Compliance Plan calculations, from June 1 to June 15, as deemed necessary by station management. Under this plan, cooling water from the condenser must first be circulated through the cooling system before a portion can be discharged to the Illinois River. The station is allowed to discharge augmented blowdown at rates between 111 cubic feet per second and 1,115 cubic feet per second. Discharge flow rates are varied in order to prevent power deratings, which could be caused by heated cooling water being recirculated to the Units 2 and 3 condensers (Ref. 10). Operation of the cooling towers is implicitly covered by the thermal requirements of Special Condition 4 of the NPDES permit.

Special Condition 7 of the NPDES Permit states that DNPS has complied with 35 Illinois Administrative Code Subpart B "General Use Water Quality Standards," Section 302.211(f) "Temperature" and Section 316(a) (Thermal effluent limits) of the Clean Water Act (CWA) in demonstrating that the thermal discharge from the station has not caused, and cannot be reasonably expected to cause, significant ecological damage to the receiving water, as approved by the Illinois Pollution Control Board (PCB) in PCB Order 73-359 dated January 17, 1974, and PCB Order 79-134 dated July 9, 1981. The special condition further states that no additional monitoring or modification is required for reissuance of the NPDES Permit.

Groundwater from two 1,500-foot-deep wells is used at DNPS for domestic purposes and for various industrial purposes, but not for condenser cooling. The proposed EPU will not affect groundwater use.

The station monitors wastewater streams as required by the NPDES Permit and only uses approved chemicals for conditioning water to prevent scaling, corrosion, and biofouling (Ref. 5). Because an increase in the design capacity to withdraw water from the Kankakee and Des Plaines Rivers is not proposed for EPU, none of these practices will be altered.

ComEd does not seek to change NPDES permit requirements for thermal or flow conditions for the proposed EPU. Rather, additional mechanical draft cooling tower cells will be installed to meet current thermal limits during the critical summer period. The DNPS cooling towers rely on non-chemical methods for biofouling control. Because flow rates, water sources, and thermal discharges will continue to be subject to existing NPDES permit requirements, there will be no additional impacts associated with the EPU beyond those considered in the NPDES permit.

- Aquatic Resources Effects

The Illinois River, formed by the confluence of the Des Plaines and Kankakee Rivers, is a major drainage system for the State of Illinois. The drainage covers a distance of 332 river miles and encompasses an area of over 18.5 million acres in Illinois, Wisconsin, and Indiana. Major tributaries include the Des Plaines, Fox, Kankakee, Vermilion, Mackinaw, Sangamon, Spoon, and LaMoine Rivers. Major cities along its route include La Salle, Peru, Ottawa, Peoria, Pekin, and East Peoria (Ref. 12). Since the late 1800s, the Illinois River has undergone extensive changes. In 1871, the flow of the Chicago River was reversed in order to divert sanitary wastes from the City of Chicago away from Lake Michigan to protect the drinking water source for the City. The polluted water of the Chicago River was directed through the Illinois and Michigan (I&M) Canal into the Des Plaines River and subsequently into the Illinois River. The Chicago Sanitary & Ship Canal (CSSC) was opened in 1900, bringing with it several thousand cubic feet per second of diverted Lake Michigan water. The new canal was cut into the channels of the South Branch of the Chicago River and the I&M Canal through the Chicago Portage area. At that point, it becomes a separate third channel parallel to the Des Plaines River and the old I&M Canal. About 40 miles downstream, it enters the Des Plaines River between Lockport and Joliet (Ref. 13).

In 1919, the state began constructing the Illinois Waterway, which created a new, larger channel through the Chicago River, the CSSC, the Des Plaines River, and the Illinois River, shaping them into a continuous navigation route at least 9 feet deep and at least 300 feet wide from Lake Michigan to the Mississippi River. The waterway project required construction of seven major locks and a new set of relatively higher dams. There is a dam at Dresden Island, approximately two miles downstream from the confluence of the Kankakee and Des Plaines Rivers, where the DNPS is located (Ref. 13).

Dresden Island Pool is a flooded river drainage that has a fair amount of "natural" shoreline area and a number of natural tributaries. There are a wide variety of historical and current sources of pollutants to this pool. As a result, the water column and sediments have been contaminated by the numerous industries along the river and its tributaries (Ref. 13).

The ecology of the area surrounding the DNPS cooling pond, intake and discharge, has been studied extensively since the late 1960s. Studies of the lower trophic levels (phytoplankton, zooplankton, periphyton, and benthic invertebrates), as well as the fish community, indicate that operation of DNPS has not had a measurable, detrimental impact on the ecology of the Illinois River system (Ref. 14). Surveys of the fish community in the vicinity of the Dresden Station have been conducted annually since 1971 (Ref. 14). These studies have monitored the fish populations near the confluence of the Kankakee and lower Des Plaines River and in the Illinois River within the Dresden Island Pool. The Dresden Island Pool area includes sampling stations near the intake and discharge areas of DNPS. These studies have concluded that the fish community in the area of DNPS has improved since the studies began. For example, the number of species collected by the various collection methods increased from the 1970's through the early to mid-1980's and leveled off in the early 1990's (Ref. 14). The increases in species richness that occurred during the 1980's were primarily the result of more cyprinid (i.e., minnow) and sunfish species. Since the 1970's, water quality has also improved in the Kankakee and lower Des Plaines Rivers and these increases in species richness could be related to that improvement (Ref. 14). Regardless, the operation of DNPS has not had a measurable, detrimental environmental impact on the fishery community.

ComEd conducted impingement sampling at the traveling intake screens at DNPS from 1977 to 1987. The study concluded that the number of fish impinged at the station was low and that the fishery in the adjacent river system is not being adversely impacted by operations at DNPS. Therefore, in April 1987, the Illinois Department of Conservation agreed to eliminate impingement sampling from the DNPS Aquatic Monitoring Program. No Federally listed fish species have been collected in the vicinity of DNPS. However, three Illinois listed species, the pallid shiner and greater redhorse, listed as endangered, and the river redhorse, listed as threatened, have been collected near DNPS. The pallid shiner has only been collected downstream of Dresden Island Lock and Dam. The two redhorse species both prefer more complex channel substrate (i.e., boulder, rubble, and gravel) than would be found in the impounded Dresden Island Pool around DNPS. Routine monitoring of the fishery community continues in the Kankakee, Des Plaines, and Illinois Rivers.

ComEd submitted information for the DNPS intake structure to the IEPA pursuant to Section 316(b) of the Clean Water Act. IEPA, in turn, determined that additional monitoring is not required, but further monitoring may be necessary at the time of any modification or reissuance of the NPDES permit. Implementation of the EPU will not require any changes in the intake structure or intake flows at DNPS. Therefore, impacts to fish and shellfish in the early life stages due to the EPU will not change.

3.3 Radiological Environmental Impacts

➢ Radioactive Waste Streams

The radioactive waste systems at DNPS are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design bases for these systems during normal operation are to limit discharges in accordance with 10 CFR 20, to limit exposures to the requirements of 40 CFR 190, and to satisfy the design objectives of 10 CFR 50 Appendix I. Adherence to these limits and objectives will continue under the proposed EPU.

Operation at EPU conditions will not result in any physical changes to the solid waste, liquid waste, or gaseous waste systems. The safety and reliability of these systems is unaffected by the proposed EPU. Also, EPU does not affect the environmental monitoring of any of these waste streams and the radiological monitoring requirements of the DNPS Technical Specifications will not be affected. Under normal operating conditions, EPU does not introduce any new or different radiological release pathways and does not increase the probability of an operator error or equipment malfunction that would result in an uncontrolled radioactive release from the radioactive waste streams. The specific effects of the proposed EPU on each of the radioactive waste systems are evaluated in the following paragraphs.

Solid radioactive wastes include solids recovered from the reactor process system, solids in contact with reactor process system liquids or gases, and solids used in the reactor process system operation. The largest volume of solid radioactive waste at DNPS is low level radioactive waste (LLRW). Sources of LLRW present at DNPS include resins, filter sludge, dry active waste, metals, oil, etc. The annual burial volume of LLRW generated in 1998 was 208.40 cubic meters (m^3); in 1999 the burial volume decreased to 98.44 m^3; and the projected burial volume of LLRW in 2000 is approximately 144 m^3. One-time increases in the burial volume of LLRW associated with EPU installations are projected for each unit. The volume of resin is expected to increase by as much as 17 percent at EPU conditions, due to increased iron removal in the condensate system from the increased feedwater flow. A 17 percent increase in resin volume projected onto the expected year 2000 LLRW burial volume results in a 156 m^3 per year post-EPU LLRW burial volume (i.e., 8 percent increase), which is bounded by the FES.

The number of fuel assemblies will increase in any given core load with the proposed EPU, reducing storage space in the spent fuel pool. The increased spent fuel storage needs from EPU are accommodated in the design for spent fuel dry storage, currently being developed at DNPS pursuant to 10 CFR Part 72, Subpart K "General License for Storage of Spent Fuel at Power Reactor Sites." At current off-load rates, four dry storage casks will be filled during each refueling outage with a fifth dry storage cask partially filled. DNPS plans to complete the fifth cask using the inventory of assemblies from the spent fuel pool. At EPU conditions, each refueling outage will also fill four casks and partially fill a fifth.

However, fewer assemblies from the spent fuel pool will be needed to complete the fifth dry storage cask. The net effect of EPU will be to increase the number of dry storage casks needed by three to four every five years.

Liquid radioactive wastes include liquids from the reactor process systems and liquids that have become contaminated with process system liquids. Table 3-4 presents liquid releases from DNPS for the most recent five-year period. Water processed in the liquid radioactive waste treatment system follows one of two pathways. Water that has been demineralized and purified is typically treated and reused. Water that has come in contact with organics or other impurities that make it unsuitable for reuse is treated and released. Increases in flow rate through the condensate demineralizers and increases of fission products and activated corrosion products are expected at EPU conditions, resulting in additional backwashes of condensate demineralizers and reactor water cleanup filter-demineralizers. These additional backwashes will be processed through the liquid radioactive waste treatment system and are expected to be suitable for reuse. Therefore, liquid effluent release volumes are not expected to increase significantly as a result of EPU. No changes in the liquid radioactive waste treatment system are proposed. Therefore, average treatment efficiency will not change and the radioactivity of liquid effluent releases may increase up to the

Table 3-4. Liquid and Gaseous Effluents 1995 - 1999.[a]

	1995	1996	1997	1998	1999	Average 1995-1999
Liquid Effluents Released to Receiving Waters (Ci)[b]						
Fission and Activation Products	5.99×10^{6} l[c] 6.21×10^{-2}	1.24×10^{7} l[c] 2.75×10^{-2}	6.61×10^{6} l[c] 1.41×10^{-2}	2.24×10^{7} l[c] 4.11×10^{-2}	1.64×10^{7} l[c] 3.77×10^{-1}	**1.27×10^{7} l[c]** **1.04×10^{-1}**
Tritium	2.60×10^{0}	1.22×10^{1}	1.25×10^{1}	5.21×10^{1}	7.71×10^{1}	**3.13×10^{1}**
Alpha	BDL[d]	BDL[d]	BDL[d]	BDL[d]	BDL[d]	**BDL[d]**
Gaseous Effluents Released to the Atmosphere (Ci)[b]						
Fission and Activation Gases	8.81×10^{1}	6.58×10^{1}	2.43×10^{2}	2.03×10^{2}	1.26×10^{2}	**1.45×10^{2}**
Iodine-131	6.43×10^{-4}	1.30×10^{-3}	5.86×10^{-3}	5.75×10^{-3}	5.20×10^{-3}	**3.75×10^{-3}**
Beta-Gamma[e]	1.43×10^{-2}	2.15×10^{-3}	7.97×10^{-3}	1.05×10^{-2}	1.21×10^{-2}	**9.40×10^{-3}**
Alpha	2.78×10^{-6}	BDL[d]	3.92×10^{-6}	2.51×10^{-5}	2.42×10^{-5}	**1.40×10^{-5}**
Tritium	4.77×10^{0}	2.63×10^{0}	5.96×10^{0}	7.56×10^{0}	3.41×10^{1}	**1.10×10^{1}**
Total	9.29×10^{1}	6.84×10^{1}	2.49×10^{2}	2.11×10^{2}	1.60×10^{2}	**1.56×10^{2}**

a. Source: (Ref. 15, 16, 17, 18, and 19)
b. Ci = curies
c. l = liters
d. BDL - Below Detectable Levels
e. Beta-gamma as particulates

NOTE: Since below detectable levels do not have an assigned quantitative value, they were not included in the average total. The average total in these cases is more conservative than rows containing all quantitative values.

17 percent proposed power uprate. Expected DNPS liquid effluents at EPU conditions will continue to be within the regulatory limits of 10 CFR 50 Appendix I.

Gaseous radioactive wastes principally include activation gases and fission product radioactive noble gases vented from process equipment, and under certain conditions, the building ventilation exhaust air. The major sources of gaseous radioactive wastes are the condenser air ejector effluent and steam packing exhaust system effluent. Table 3-4 presents gaseous releases from DNPS for the most recent five-year period. Based on the conservative assumption of a non-negligible amount of fuel leakage due to defects, radioactive releases are estimated to increase proportionally to the 17 percent EPU. However, the current and expected fuel defect rate is extremely small. Therefore, the expected gaseous effluents for all radionuclides will remain bounded by the FES.

No increase in gaseous wastes is expected from any new fuel designs, because ComEd's contract with General Electric contains a warranty section that requires General Electric to meet a specified level of fuel performance. This level is at least as stringent as that imposed on current fuel designs.

In summary, solid radioactive waste burial volume is estimated to increase by approximately 8 percent and the radioactivity of liquid effluent releases and gaseous radioactive effluent release volume may increase up to 17 percent as a result of EPU. The liquid radioactive release volume is not expected to increase. The proposed EPU will not introduce any new or different radiological release pathways.

➢ Radiation Levels and Offsite Dose

Offsite dose from radioactive effluents and direct radiation is monitored at DNPS using two types of monitoring stations: radiation monitors and sampling monitors. Direct radiation monitoring consists of two thermoluminescent dosimeters (TLDs), provided at each location to monitor the integrated radiation exposure. Sampling monitors consist of particulate and iodine air samplers. Monitoring is performed at onsite and offsite locations, as described in the Offsite Dose Calculation Manual (ODCM).

Offsite dose from liquid effluents are summarized and averaged for 1995 through 1999 (Table 3-5) according to 10 CFR 50 Appendix I as reported in the Annual Radiological Environmental Operating Reports for the station. For the five year period, average annual whole body dose was 4.25×10^{-3} mrem, and average annual dose to the critical organ was 6.16×10^{-3} mrem. The highest percentage of 10 CFR 50 Appendix I regulatory limits for maximum dose resulting from liquid releases to an adult receptor for the five year period occurred in 1999 and was 0.07 percent of the critical organ dose limit (Table 3-5). The average

Table 3-5. Liquid and Gaseous Effluents Dose Pathways 1995-1999[a]

	1995	1996	1997	1998	1999	Average 1995-1999 (Regulatory limits)
Maximum Dose						
Liquid Effluent Pathways						
Whole Body (mrem)[b]	1.76×10^{-3}	9.76×10^{-4}	4.77×10^{-4}	1.67×10^{-3}	1.64×10^{-2}	**4.25×10^{-3} (3)[e]**
Critical Organ (mrem)[b]	3.94×10^{-3}	1.47×10^{-3}	6.99×10^{-4}	8.33×10^{-3}	1.64×10^{-2}	**6.16×10^{-3} (25)[d]**
Gaseous Effluent Pathways						
Skin (mrem)[b]	7.15×10^{-4}	7.95×10^{-4}	5.14×10^{-3}	3.06×10^{-3}	1.96×10^{-3}	**2.33×10^{-3} (15)[e]**
Gamma Air Dose (mrad)[c]	8.31×10^{-4}	9.11×10^{-4}	6.23×10^{-3}	3.65×10^{-3}	2.35×10^{-3}	**2.79×10^{-3} (10)[e]**
Beta Air Dose (mrad)[c]	9.71×10^{-5}	1.05×10^{-4}	3.81×10^{-4}	2.94×10^{-4}	1.66×10^{-4}	**2.08×10^{-4} (20)[e]**
Critical Organ (mrem)[b]	3.61×10^{-2}	7.89×10^{-3}	1.79×10^{-2}	1.78×10^{-2}	3.22×10^{-2}	**2.23×10^{-2} (25)[d]**
Whole Body (mrem)[b]	1.26×10^{-3}	1.45×10^{-3}	7.30×10^{-3}	2.75×10^{-3}	1.77×10^{-3}	**2.90×10^{-3} (25)[d]**
Infant Thyroid (mrem)[b]	3.28×10^{-2}	5.57×10^{-3}	1.66×10^{-2}	1.66×10^{-2}	2.10×10^{-2}	**1.85×10^{-2} (15)[e]**
Sky Shine						
Whole Body (mrem)[b]	1.54×10^{0}	1.52×10^{0}	3.54×10^{0}	4.04×10^{0}	6.24×10^{0}	**3.38×10^{0} (25)[d]**

a. Source: (Ref. 15, 16, 17, 18, and 19).
b. mrem = millirem
c. mrad = millirad
d. 40 CFR 190
e. 10 CFR 50, Appendix I
Note: Regulatory limits specify a generic organ dose limit, nuclide specific critical organ limits may be lower depending on effluent composition.

dose compared with 10 CFR 50 Appendix I regulatory limits from 1995 through 1999 was 0.02 percent of the regulatory limit.

No significant change in the volume of water treated and released is expected as a result of EPU. The offsite dose from liquid effluents is projected to increase proportionally to EPU due to the increase in concentration of fission products and activation products in the reactor coolant. Offsite dose will remain well below 10 CFR 50 Appendix I standards.

Doses to individuals from gaseous releases are summarized and averaged for 1995 through 1999 (Table 3-5) according to 10 CFR 50 Appendix I categories as reported in the Annual Radiological Environmental Operating Reports for the station. For the five year period, average annual total body dose was 2.90×10^{-3} mrem, and average annual dose to the critical organ was 2.23×10^{-2} mrem. The highest percentage of 10

CFR 50 Appendix I regulatory limits for maximum dose resulting from airborne releases to an adult receptor for the five year period occurred in 1995 and was 0.14 percent of the critical organ dose limit (Table 3-5). The average dose compared with Appendix I regulatory limits from 1995 through 1999 was 0.09 percent of the regulatory limit.

Offsite dose from gaseous effluents depends heavily on fuel performance. Current and expected fuel defect rates are significantly better than design. Conservatively assuming a non-negligible amount of fuel leakage due to defects, gaseous effluents will increase proportionally to the 17 percent EPU. However, offsite dose will remain well below 10 CFR 50 Appendix I standards.

Calculated offsite dose resulting from direct radiation due to radiation levels in plant components (i.e., sky shine) will increase up to 17 percent because the ODCM conservatively proportions offsite dose to power generation. Since sky shine is the dominant contributor to total offsite dose, the calculated total offsite dose from the ODCM will increase up to 17 percent. Actual offsite dose from sky shine is not expected to increase significantly because the decrease in transit time is expected to result in a minimal change in concentration through reduced decay time and because the expected activity concentration in the steam will remain constant due to the dilution effect of a 19 percent increase in steaming rate. The expected dose at EPU conditions will remain significantly below the standards of 10 CFR 50 Appendix I, 10 CFR 20, and 40 CFR 190.

➢ Occupational Radiation Exposure

Radiation levels and associated doses are controlled by the As Low As Reasonably Achievable (ALARA) program as required by 10 CFR 20. ComEd has a policy to maintain occupational dose equivalents to the individual and the sum of dose equivalents received by all exposed workers to ALARA levels. This ALARA philosophy is implemented in a manner consistent with DNPS operating, maintenance, and modification requirements and accounts for the state of technology, the economics of improvements relative to the state of technology, the economics of improvements relative to public health and safety benefits, the public interest relative to utilization of nuclear energy and licensed materials, and other societal and socioeconomic considerations.

The DNPS ALARA program manages exposure by:

A. Minimizing the time personnel spend in radiation areas,

B. Maximizing the distance between personnel and radiation areas, and

C. Maximizing shielding to minimize radiation levels in routinely occupied plant areas and in the vicinity of plant equipment requiring attention.

Shielding is used throughout the station to protect personnel against radiation emanating from the reactors, the turbines, and their auxiliary systems, and to limit radiation damage to operating equipment. ComEd has determined that the current shielding designs are adequate for any dose increase that may occur after the EPU.

For EPU, normal operation radiation levels will increase by no more than the percentage increase of EPU. For conservatism, many aspects of the plant were originally designed for higher-than-expected radiation sources. Thus, the increase in radiation level does not affect radiation zoning or shielding in the various areas of the plant because it is offset by conservatism in the original design, source terms used, and analytical techniques (Ref. 20). Therefore, no new dose reduction programs are scheduled and the ALARA program will continue in its current form.

At EPU conditions, a potential source of increased occupational radiation results from a projected increase in moisture carryover from the reactor vessel steam dryer/separator to the main steam lines. To reduce moisture content under EPU conditions, modifications to the steam dryer/separator will be required. These modifications are expected to result in a negligible increase in occupational exposure.

3.4 Environmental Impacts of Accidents

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operational envelope) that results in the release or a potential for release of radioactive materials to the environment. The realistic consequences of postulated accidents presented in Table 3-6 were calculated by the AEC and published in the FES (Ref. 2). The accident scenarios for this assessment follow the realistic guidance provided in Regulatory Guide 4.2. The radiological dose consequences are provided as fractions of 10 CFR 20 limits. The realistic assessments made for environmental impact studies result in lower doses than those which would be seen for the conservative design basis safety assessments (Ref. 21). Because of the different scenarios, the accident consequences of the realistic assessments in the FES and the conservative, design-bases assessments of the UFSAR are not comparable.

The results presented in Table 3-6 could be recalculated for the 17 percent higher EPU power level. The resulting doses would be approximately 17 percent higher. Since the doses from the realistic accident analysis of Table 3-6 are currently well within 10 CFR 20 limits, a 17 percent increase results in doses that also remain well within these limits. Therefore, the realistic consequences of the accidents under EPU conditions are acceptable.

3.5 Environmental Effects of Decommissioning

The environmental effects of decommissioning were not evaluated in the FES. The ability to maintain sufficient financial reserves for decommissioning is not affected by EPU. The environmental effects of decommissioning will be addressed in the DNPS decommissioning plan that will be submitted according to the applicable regulatory requirements. EPU may impact decommissioning due to increases in feedwater flow rate and increased neutron fluence. These effects could increase the amount of activated corrosion products and consequently increase post-shutdown radiation levels.

Table 3-6. Summary of Radiological Consequences of Postulated Accidents.[a]

Class	Event	Estimated Fraction of 10 CFR Part 20 Limit at Site Boundary[b]	Estimated Dose to Population in 50-mile Radius, person-rem
1.0	Trivial incidents	(c)	(c)
2.0	Small releases outside containment	(c)	(c)
3.0	Radwaste system failures		
3.1	Equipment leakage or malfunction	0.087	17
3.2	Release of waste gas storage tank contents	0.35	69
3.3	Release of liquid waste storage contents	<0.001	<0.1
4.0	Fission products to primary system (BWR)		
4.1	Fuel cladding defects	(c)	(c)
4.2	Off-design transients that induce fuel failures above those expected	0.004	1.8
5.0	Fission products to primary and secondary systems (PWR)	NA[d]	NA[d]
6.0	Refueling accidents		
6.1	Fuel bundle drop	0.002	0.4
6.2	Heavy object drop onto fuel in core	0.015	3.0
7.0	Spent fuel handling accident		
7.1	Fuel assembly drop in fuel rack	0.003	0.66
7.2	Heavy object drop onto fuel rack	0.006	1.2
7.3	Fuel cask drop	0.13	26
8.0	Accident initiation events considered in design basis evaluation in the SAR		
8.1	Loss-of-coolant accidents		
	Small break	<0.001	<0.1
	Large break	0.26	41
8.1(a)	Break in instrument line from primary system that penetrates the containment	<0.001	<0.1
8.2(a)	Rod ejection accident (PWR)	NA[d]	NA[d]
8.2(b)	Rod drop accident (BWR)	0.004	2.1
8.3(a)	Steamline breaks (PWR's outside containment)	NA[d]	NA[d]
8.3(b)	Steamline breaks (BWR)		
	Small break	0.003	0.6
	Large break	0.015	3.1

Source: (Ref. 2).

a. The doses calculated as consequences of the postulated accidents are based on airborne transport of radioactive materials resulting in both a direct and an inhalation dose.

b. Represents the calculated fraction of a whole body dose of 500 mrem, or the equivalent dose to organ.

c. These releases are expected to be a small fraction of 10 CFR 20 limits for either gaseous or liquid effluents.

d. NA = Not applicable.

4.0 ALTERNATIVES

This section evaluates the environmental impacts of alternatives to the DNPS proposed EPU. Unit 2 and Unit 3 will each be uprated from 2,527 MWt to 2,957 MWt, resulting in a gross increase of 206 MWe for both units. The discussion includes an assessment of the "no action" alternative and alternatives that meet incremental changes in system generating capacity.

4.1 No-Action Alternative

ComEd is using the "no-action" alternative to refer to a scenario in which the station continues to operate under current power levels. Under this alternative, station operation and associated environmental impacts would not be different from those currently allowed through the various permits approved by the regulatory agencies and ComEd would develop an alternate energy strategy.

4.2 Alternatives That Meet Incremental Changes in System Generating Capacity

Based on 1998 generation data for the State of Illinois (Ref. 22), the primary energy sources for electric generation are coal (53.6 percent), nuclear (42.4 percent), gas (3.4 percent), and petroleum (0.6 percent). ComEd has concluded that pulverized coal- and gas-fired units are the only reasonable alternatives to EPU for incremental increases in generation capacity.

Recently the electric utility industry in the State of Illinois has begun the process of restructuring (i.e., deregulation). It is expected that the State will be fully deregulated by May 1, 2002 (Ref. 23). It is generally perceived that a deregulated market will provide the benefits of lower energy costs, greater choice for customers, and economic efficiency. A number of companies have proposed to construct new generating facilities in Illinois since the deregulation law was enacted. Citizens, local governments, and legislators objected to a number of the proposed plants. In response, the Illinois Pollution Control Board has been conducting hearings to evaluate whether additional siting and/or other regulation of such proposed plants should be recommended (Ref. 6). Regardless of which entities construct and operate the replacement power supply, certain environmental parameters would be constant among these alternative power sources. Therefore, ComEd will discuss the impacts of these reasonable alternatives for the DNPS EPU.

4.2.1 CONSTRUCT AND OPERATE A FOSSIL-FUEL-FIRED GENERATING STATION

ComEd analyzed hypothetical new coal- and gas-fired units at the existing DNPS site. Under this approach, DNPS would construct a separate generating facility, but would minimize certain environmental impacts by building on previously disturbed land and by utilizing existing facilities, transmission lines, roads and parking areas, office buildings, and cooling systems to the greatest extent practicable. Infrastructure improvements for EPU, such as the addition of cooling tower cells, are assumed to be necessary for the fossil fuel-fired alternatives.

For comparability in analysis, ComEd selected coal- and gas-fired units of equal electric power and equal capacity factors. Therefore, to meet the demands of the proposed EPU presented in Section 4.0, ComEd selected alternative units of 206 gross MWe. It must be emphasized, however, that these are hypothetical scenarios and ComEd does not have plans for such construction at DNPS.

Coal-Fired Generation

The NRC, in considering extension of the operating licenses for Calvert Cliffs (Ref. 24) and Oconee (Ref. 25) Nuclear Stations, evaluated coal-fired generation alternatives. For Calvert Cliffs, NRC analyzed three 600 MWe units and for Oconee, NRC analyzed four 522 MWe units and two 1,185 MWe units. ComEd has reviewed the NRC analysis and believes it to be sound. Therefore, ComEd has used site- and Illinois-specific input and has scaled from the NRC analysis, where appropriate.

Table 4-1 presents the basic coal-fired alternative emission control characteristics. ComEd based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions. Coal and limestone (or lime) would be delivered via rail line to an existing rail spur that leads to DNPS. The rail system at DNPS would require modifications to handle these increased rail deliveries.

Table 4-1. Coal-Fired Alternative.

Characteristic	Basis
Unit size = 206 MW ISO rating gross[a]	Chosen as equal to proposed extended EPU
Unit size = 194 MW ISO rating net[a]	Calculated based on 6 percent onsite power usage (ComEd experience): 206 MW x 0.94
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (Ref. 26, Table 1.1-3, page 1.1-17).
Fuel type = bituminous, pulverized coal	Typical for coal used in Illinois (ComEd experience)
Fuel heating value = 9,706 Btu/lb	1998 value for coal used in Illinois (Ref. 27, Table 28)
Fuel ash content by weight = 7.1 percent	1998 value for coal used in Illinois (Ref. 27, Table 28)
Fuel sulfur content by weight = 1.12 percent	1998 value for coal used in Illinois (Ref. 27, Table 28)
Uncontrolled NO_x emission = 9.7 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, pre-NSPS with low- NO_x burner (Ref. 26, Table 1.1-3, page 1.1-17)
Heat rate = 10,200 Btu/Kwh	Typical for coal-fired, single-cycle steam turbines (Ref. 28, page 106)
Capacity factor = 0.75	Typical for small coal-fired units (ComEd experience)

Table 4-1. (Continued).

Characteristic	Basis
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (Ref. 26, Table 1.1-2, page 1.1-14).
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (Ref. 26, pages 1.1-6 and -7)
SO_x control = Wet scrubber-lime/limestone (95 percent removal efficiency)	Best available for minimizing SO_x emissions (Ref. 26, Table 1.1-1, page 1.1-13)

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
KWh = kilowatt hour
NSPS = New Source Performance Standard
lb = pound
MW = megawatt
NO_x = nitrogen oxides
SO_x = sulfur oxides

Gas-Fired Generation

ComEd has chosen to evaluate gas-fired generation using combined-cycle turbines, because it has determined that the technology may be sufficiently mature, economical, and feasible for implementation at DNPS. Gas-fired combined-cycle turbines are readily available in a standard-sized unit of 206 MW and are more economical than customized units. Therefore, ComEd selected this unit size. Table 4-2 presents the basic gas-fired alternative characteristics. Employing this alternative would require, as a minimum, a new 16-inch dedicated, high pressure pipeline extended at least two miles to the Station. A constant supply of natural gas may not be readily available from this source, leading to further supply and reliability issues.

Table 4-2. Gas-Fired Alternative.

Characteristic	Basis
Unit size = 206 MW ISO rating gross:[a] One 137-MW combustion turbines and a 69-MW heat recovery boiler	Chosen as equal to proposed extended EPU
Unit size = 198 MW ISO rating net:[a] One 132-MW combustion turbine and a 66-MW heat recovery boiler	Calculated based on 4 percent onsite power usage
Fuel type = natural gas	Assumed
Fuel heating value = 1,018 Btu/ft^3	1998 value for gas used in Illinois (Ref. 27, Table 28)
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available (Ref. 29, Table 3.1-2a, page 3.1-11)
NO_x control = selective catalytic reduction (SCR)	Best available for minimizing NO_x emissions (Ref. 30, Table 3.1 Database)
Fuel NO_x content = 0.0128 lb/MMBtu	Typical for SCR-controlled gas-fired units (Ref. 30, Table 3.1 Database)
Fuel CO content = 0.0168 lb/MMBtu	Typical for SCR-controlled gas-fired units (Ref. 30, Table 3.1 Database)
Heat rate = 8,200 Btu/Kwh	Typical for combined-cycle gas-fired turbines (Ref. 28, page 106)
Capacity factor = 0.75	Assumed same as coal for comparison

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu	=	British thermal unit
ft^3	=	cubic foot
ISO rating	=	International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
KWh	=	kilowatt hour
MM	=	million
MW	=	megawatt
NO_x	=	nitrogen oxides

4.3 Environmental Impacts of Alternatives

This section evaluates the environmental impacts from potentially available alternatives for the incremental increase in power that would be generated as a result of the approval of an amendment to the operating license for DNPS Units 2 and 3.

4.3.1 Coal-Fired Generation

The coal-fired alternative that ComEd has defined in Section 4.2.1 would be located at the existing DNPS site on previously disturbed land, thus reducing construction impacts. The alternative would use the infrastructure of existing cooling water system with additional cooling tower cells, and operate within the bounds of the existing NPDES permit, thereby minimizing aquatic impacts. For this comparison, it is also assumed that the heat rejection from a coal fired generating unit would be equivalent to EPU. Therefore, ComEd has limited its detailed evaluation to impacts that would be different with implementation of the EPU. These impacts are associated with changes in air quality, waste management, and land use.

Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant would emit sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM), all of which are regulated pollutants as well as carbon dioxide (CO_2), a potential contributor to global warming. SO_x, NO_x and CO would all be emitted in quantities in excess of major source thresholds. This may require emission offsets, the purchase of emission credits, or other control techniques beyond the combination of boiler technology and post-combustion pollutant removal assumed in this analysis. Coal-fired generation could also emit low levels of mercury and other toxic compounds adding to the atmospheric deposition of these pollutants. ComEd estimates the coal-fired alternative emissions to be as follows:

SO_x = 757 tons per year
NO_x = 172 tons per year
CO = 178 tons per year
Total suspended particulates (TSP) = 25 tons per year
PM_{10} (PM diameter less than 10 microns) = 6 tons per year

Table 4-3 presents the equations ComEd used to calculate these emissions from the characteristics described in Table 4-2.

Emissions of NO_x from the electric power industry in Illinois increased by 3 percent from 1988 to 1998 (Ref. 22). In 1998, the EPA promulgated the NO_x SIP (State Implementation Plan) Call regulation that required 22 states to reduce their NO_x emissions by over 30 percent to address national ozone transport (Ref. 31). The NO_x SIP Call imposes a NO_x "budget" to limit the NO_x emissions from each state. The Illinois EPA allocated NO_x credits among the existing electrical generating units in the state. Beginning May 31, 2004, each electrical generating unit must hold enough NO_x credits to cover its annual NO_x emissions. A small percentage of NO_x credits was set aside for new sources. New sources of NO_x must obtain enough NO_x credits to cover their annual emissions either from the set aside pool or by buying NO_x credits from other sources.

The acid rain requirements of the Clean Air Act Amendments capped the nation's sulfur dioxide (SO_2) emissions from power plants. Each utility was allocated SO_2 allowances. To be in compliance with the Act, ComEd must hold enough allowances to cover its annual SO_2 emissions. ComEd may have to purchase additional allowances from the open market to operate a fossil-fuel-burning plant at DNPS.

Table 4-3. Air Emissions from Coal-Fired Alternative Using System Characteristics Listed in Table 4-1

Parameter	Calculation	Result
Annual coal consumption	$1\text{ units}\times\frac{206\text{ MW}}{\text{unit}}\times\frac{10{,}200\text{ Btu}}{\text{kW}\times\text{hr}}\times\frac{1{,}000\text{ kW}}{\text{MW}}\times\frac{\text{lb}}{9{,}706\text{ Btu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times 0.75\times\frac{24\text{ hr}}{\text{day}}\times\frac{365\text{ day}}{\text{yr}}$	711,152 tons of coal per year
SO_2	$\frac{38^{a}\times 1.12\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\left(1-\frac{95}{100}\right)\times\frac{711{,}152\text{ tons}}{\text{yr}}$	757 tons SO_2 per year
NO_x	$\frac{9.7\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\left(1-\frac{95}{100}\right)\times\frac{711{,}152\text{ tons}}{\text{yr}}$	172 tons NO_x per year
CO	$\frac{0.5\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{711{,}152\text{ tons}}{\text{yr}}$	178 tons CO per year
TSP	$\frac{10^{a}\times 7.1\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\left(1-\frac{99.9}{100}\right)\times\frac{711{,}152\text{ tons}}{\text{yr}}$	25 tons TSP per year
PM_{10}	$\frac{2.3^{a}\times 7.1\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\left(1-\frac{99.9}{100}\right)\times\frac{711{,}152\text{ tons}}{\text{yr}}$	6 tons PM_{10} per year

a. Emission factors for pulverized coal, dry bottom, tangentially fired, bituminous Pre-NSPS with low-NO_x burner (Ref. 26, Tables 1.1-3 and 1.1-4)

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_2 = sulfur oxides
TSP = total suspended particulates

The NRC noted that adverse human effects from coal combustion have led to important Federal legislation in recent years and that public health risks, such as cancer and emphysema, are associated with coal combustion. The NRC also identified global warming and acid rain as potential impacts of coal-fired power plants. Global warming, ozone transport, mercury deposition, and acid rain are among the significant air quality concerns associated with operating coal-fired power plants. There are numerous, stringent state and federal air pollution control requirements applicable to the construction and operation of such plants, with which ComEd would be required to comply for a proposed coal-fired plant at DNPS. ComEd concludes that the coal-fired alternative would have moderate impacts on air quality and that these impacts may be noticeable, but they would not destabilize the resource.

Waste Management

In the Generic Environmental Impacts Statement for License Renewal of Nuclear Plants (GEIS), the NRC concluded that the operation of a coal-fired alternative would generate substantial solid waste (Ref. 32). ComEd concurs with this assessment. The coal-fired plant would consume approximately 711,152 tons of coal per year having an ash content of 7.1 percent (Tables 4-1 and 4-3). After combustion, most (99.9 percent) of this ash, approximately 50,441 tons per year, would be collected along with approximately 41,284 tons per year of scrubber sludge (based on annual lime usage of 13,935 tons). ComEd estimates that ash and scrubber waste disposal over the next 20 years of plant operation would require 24 acres of land for disposal, based on a standard 30-foot waste pile (Table 4-4). ComEd recycled 87 percent of its coal ash from larger plants in 1998 and could conceivably apply this program to wastes generated at DNPS, thus reducing the land required for disposal.

ComEd believes that, with proper siting, waste management, and monitoring practices, waste disposal would not destabilize any resource. There is potential space within the DNPS footprint for this disposal. Most of the land needed could be obtained by converting approximately 24 acres of previously disturbed land to waste disposal (less with recycling). Significant engineering and public relations issues may develop from siting a land disposal unit at DNPS. The Illinois EPA maintains strict construction standards for disposal facilities which may be cost prohibitive to implement or add to the complexity of the operation (i.e., leachate collection and treatment systems). Additionally, negative public reaction to a land disposal unit in close proximity to residential areas may make on-site management of solid wastes unattractive. The landfill would most likely be above grade due to the proximity to the river and the local groundwater table. After closure, the area would have limited value. For these reasons, ComEd believes that waste disposal for the coal-fired alternative could have a moderate

Table 4-4. Calculation of Solid Waste from Coal-Fired Alternative.

Parameter	Calculation	Result
SO_2 generated	$\frac{1.12 \text{ tons S}}{100 \text{ tons coal}} \times \frac{711{,}152 \text{ tons}}{\text{yr}} \times \frac{64.100 \text{ tons } SO_2}{32.066 \text{ tons S}}$	15,922 tons SO_2 per year
SO_2 removed	$\frac{1.12 \text{ tons S}}{100 \text{ tons coal}} \times \frac{711{,}152 \text{ tons}}{\text{yr}} \times \frac{64.100 \text{ tons } SO_2}{32.066 \text{ tons S}} \times \frac{95}{100}$	15,126 tons SO_2 per year
Ash generated	$\frac{7.10 \text{ tons ash}}{100 \text{ tons coal}} \times \frac{99.9}{100} \times \frac{711{,}152 \text{ tons}}{\text{yr}}$	50,441 tons ash per year
Annual lime consumption	$\frac{15{,}922 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	13,935 tons CaO per year
Annual calcium sulfate generation	$\frac{15{,}126 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons } CaSO_4 * 2H_2O}{64.1 \text{ tons } SO_2}$	40,587 tons $CaSO_4*2H_2O$ per year
Annual scrubber waste generation	$\frac{13{,}935 \text{ tons CaO}}{\text{yr}} \times \frac{100-95}{100} + 40{,}587 \text{ tons } CaSO_4 2H_2O$	41,284 tons scrubber waste per year
Total volume of scrubber waste	$\frac{41{,}284 \text{ tons}}{\text{yr}} \times 20 \text{ yr} \times \frac{2000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	11,406,889 ft^3 Scrubber waste
Total volume of ash generated	$\frac{50{,}441 \text{ tons}}{\text{yr}} \times 20 \text{ yr} \times \frac{2000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	20,176,522 ft^3 Ash
Total volume of solid waste	$11{,}406{,}889 \, ft^3 + 20{,}176{,}522 \, ft^3$	31,583,411 ft^3 Solid waste
Waste pile area (acre)	$\frac{31{,}583{,}411 \, ft^3}{30 \text{ ft high}} \times \frac{\text{acre}}{43{,}560 \, ft^2}$	24 acres Solid waste

Sources: Ref. 33 and Ref. 34

a. Calculations based on wet-scrubber-lime SO_2 control method and an annual coal consumption of 711,152 tons
b. Calculations performed using stoichometric ratios from $CaO+SO_2+2H_2O+1/2O_2 \Rightarrow CaSO_4*2H_2O$
c. Calculations assume 100 percent combustion of coal
d. Lime consumption is based on SO_2 generated and Calcium Sulfate generated is based on SO_2 removed
e. Total sludge generated includes scrubbing media carryover in the waste. Density of Coal bottom ash is 100 b/ft^3 (Ref. 35)
f. Density of Calcium Sulfate Dihydrate is 144.8 lb/ft^3
g. Assume plant life of 20 years and waste pile height of 30 ft.

impact on the local area. However, ComEd believes the impacts could be managed so that they would neither destabilize nor noticeably alter any resource in the area.

Other Impacts

Construction of the power block and coal storage area would impact some land area and associated terrestrial habitat, but because most of this is a previously disturbed area at an existing industrial site, maximizing use of existing facilities would minimize impacts. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion, sedimentation, and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Construction debris from clearing and grubbing could be disposed of onsite and municipal waste disposal capacity is available. Socioeconomic impacts from the construction workforce would be minimal, because worker relocation would not be expected due to the proximity of the nearby metropolitan areas of Joliet and Chicago, Illinois. Cultural resource impacts would not be expected because of the previously disturbed nature of the site. However, as land is cleared for waste disposal, ComEd would identify any cultural resources (e.g., historic places and archaeological sites) and develop mitigation plans for affected resources in consultation with the Illinois State Historical Preservation Office. The effects of mining and transporting 711,152 tons of coal per year and 13,935 tons of lime/limestone per year were not evaluated, but are accepted to have significant environmental impacts. For example, coal mining consequences include air quality impacts from fugitive dust, water quality impacts from acidic runoff, and aesthetic and cultural resource impacts (Ref. 32).

Operation using the existing intake, outfall, cooling pond, and cooling towers within the boundaries of the draft NPDES permit would minimize impacts to aquatic resources and water quality. The additional stacks, boilers, and rail deliveries would be an incremental addition to the visual impact from existing DNPS structures and operations. Socioeconomic impacts could result from the increase in operational workforce by 80 to 90 employees at DNPS; however, ComEd believes these impacts would be small and would be mitigated by the site's proximity to the large metropolitan areas of Joliet and Chicago, Illinois. ComEd also assumes that other construction and operation impacts would be small. In some cases, impacts would not be detectable and, in all cases, they would be minor and would neither destabilize nor noticeably alter any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that mentioned.

4.3.2 GAS-FIRED GENERATION

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants (Ref. 32). Section 4.2.1 presents the rationale for defining the gas-fired generation alternative as a combined-cycle plant at DNPS. Land-use impacts at DNPS from gas-fired units would be less than those from the coal-fired alternative. Reduced land requirements, due to construction on the existing site, a smaller facility footprint, and no ash or lime sludge disposal would reduce impacts to ecological, aesthetic, and cultural resources as well. An additional workforce of 10 to 20 employees required to operate the gas-fired facility would have minor socioeconomic impacts, if any. Human health concerns associated with air emissions, waste generation, and aquatic biota losses due to cooling water withdrawals and discharges would all be impacts of concern.

Air Quality

Natural gas is a relatively clean-burning fuel. The gas-fired alternative would release similar types of emissions, but in lesser quantities than the coal-fired alternative. Control technology for gas-fired turbines focuses on NO_x emissions. ComEd estimates the gas-fired alternative emissions to be as follows:

SO_x = 13 tons per year
NO_x = 47 tons per year
CO = 62 tons per year
TSP = 7 tons per year = PM_{10} (i.e., all PM is PM_{10})

Table 4-5 provides the equations used by ComEd to calculate these emissions based on the plant characteristics outlined in Table 4-2.

The additional emissions of NO_x and CO when added to current facility emissions, would make the station major sources for these criteria pollutants. The Section 4.3.1 discussion of regional air quality and Clean Air Act requirements is generally applicable to the gas-fired generation alternative. The effects of gas-fired generation on ozone levels, SO_2 allowances, and NO_x emissions offsets could all be issues of concern. While gas-fired turbine emissions are less than coal-fired boiler emissions, regulatory requirements are not less stringent and the emissions are still significant. Air quality impacts would be substantially less than those of coal-fired generation, but would still require emission offsets, the purchase of emission credits, control technologies, or other mitigative measures. ComEd concludes that air emission impacts from the gas-fired alternative would be moderate.

Waste Management

Gas-fired generation would result in almost no waste generation and produce minor, if any, impacts. ComEd concludes that gas-fired generation waste management impacts would be small.

Table 4-5. Air Emissions from Gas-Fired Alternative Calculated With System Characteristics From Table 4-2.

Parameter	Calculation	Result
Annual gas consumption	$1\text{ units}\times\frac{137\text{ MW}}{\text{unit}}\times\frac{8{,}200\text{ Btu}}{\text{kW}\times\text{hr}}\times\frac{1{,}000\text{ kW}}{\text{MW}}\times 0.75\times\frac{\text{ft}^3}{1{,}018\text{ Btu}}\times\frac{24\text{ hr}}{\text{day}}\times\frac{365\text{ day}}{\text{yr}}$	7,265,051,788 ft^3 per year
Annual Btu input	$\frac{7{,}265{,}051{,}788\text{ ft}^3}{\text{yr}}\times\frac{1{,}018\text{ Btu}}{\text{ft}^3}\times\frac{\text{MMBtu}}{10^6\text{ Btu}}$	7,395,823 MMBtu per year
SO_2	$\frac{0.0034\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{7{,}395{,}823\text{ MMBtu}}{\text{yr}}$	13 tons SO_2 per year
NO_x	$\frac{0.0128\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{7{,}395{,}823\text{ MMBtu}}{\text{yr}}$	47 tons NO_x per year
CO	$\frac{0.0168\text{ lb}}{\text{MMBtu}}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{7{,}395{,}823\text{ MMBtu}}{\text{yr}}$	62 tons CO per year
TSP	$\left(\frac{0.0019\text{ lb}}{\text{MMBtu}}\right)^{a}\times\frac{\text{ton}}{2{,}000\text{ lb}}\times\frac{7{,}395{,}823\text{ MMBtu}}{\text{yr}}$	7 tons filterable TSP per year
PM_{10}	$\frac{7\text{ tons TSP}}{\text{yr}}$	7 tons filterable PM_{10} per year

a. Emission factor for filterable particulate matter (Ref. 29, Table 3.1-2a)

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_2 = sulfur oxides
TSP = total suspended particulates

Other Impacts

As with the coal-fired alternative, constructing the gas-fired alternative at an existing site (such as DNPS) would reduce construction-related impacts. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be similar to the coal-fired alternative, but smaller because of the reduced site size. Socioeconomic impacts of construction would be minimal and operation of the gas-fired facility will require 10 to 20 additional employees. ComEd believes this impact would be small and would be mitigated by the site's proximity to large metropolitan areas.

One costly (i.e., approximately $1 million/mile) and potentially controversial action with potential ecological impacts would be the installation of a minimum of two miles of buried 16 inch gas pipeline to DNPS. The pipeline would require an additional 36-40 acres for an easement. ComEd would mitigate the political impacts through public hearings and apply best management practices during construction, such as minimizing soil loss and restoring vegetation immediately after the excavation is backfilled. Construction would result in the loss of some less mobile animals (e.g., frogs and turtles). Because these animals are common throughout the area, ComEd expects negligible reduction in their population as a result of construction. ComEd does not expect that installation of a pipeline would create a long-term reduction in the local or regional diversity of plants and animals.

Cultural Resources

Gas pipeline construction could require cultural resource preservation measures. ComEd anticipates that these measures would result in no detectable change in cultural resources, and that the effects would be small and would not exert a destabilizing influence on this resource. ComEd concludes that impacts to cultural resources would be small, if any.

5.0 Compliance Permits and Consultations

Table 5-1 lists environmental authorizations that ComEd has obtained for current DNPS operations. In this context, ComEd uses "authorizations" to include permits, licenses, approvals, and other entitlements.

Table 5-1. Dresden Nuclear Power Station Environmental Authorizations for Current Operations.

Agency	Authority	Requirement	Number	Expires	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.)	Facility Operating License	DPR-19 (Unit 2) DPR-25 (Unit 3)	12/22/09 01/12/11	Operation of Units 2 and 3
U.S. Department of Transportation	49 CFR, Subpart G	Registration	051500 018 0381	06/30/01	Hazardous materials shipments
IEPA	Federal Clean Water Act (33 USC 1251 et seq.); Title 35 IAC Subtitle C, Ch.1	NPDES Permit	IL0002224	10/31/05	Plant discharges to Illinois and Kankakee Rivers
IEPA	Federal Clean Air Act, Title V; IRS Ch. 111-1/2, Sec. 1039	Federally Enforceable State Operating Permit	App. # 73020783	09/17/01	Air emissions from boilers and generators
IEPA	Federal Clean Air Act, Title V; IRS Ch. 111-1/2, Sec. 1039	Construction permit	App. # 99120062	Issued: 03/22/00	Construction of 48 auxiliary cooling towers, air emission source
IEPA	Federal Clean Water Act (33 USC 1251 et seq.); Title 35 IAC Subtitle C, Ch.1	Construction permit	2000-EN-5527	Not Applicable	Construction of 48 auxiliary cooling towers, for NPDES compliance
IEPA	Resource Conservation & Recovery Act (42 USC 6901 et seq.); (35 IAC 703)	RCRA Part A Permit	ID No. ILD000665 489	Not Applicable	Storage of radioactive hazardous (i.e. mixed waste)
IDNR	17 IAC 3702	Dam Permit	18180	12/18/84, no expiration	Cooling Pond
IEPA	Federal Clean Air Act, Title V; IRS Ch. 111-1/2, Sec. 1039	Open Burning Permit	ID# 031600 Location ID# 161807AA B	02/16/01	Burning for Fire Fighter Training

USC = United States Code
IEPA = Illinois Environmental Protection Agency
IAC = Illinois Administrative Code
IRS = Illinois Revised Statutes
IDNR = Illinois Department of Natural Resources

6.0 ENVIRONMENTAL EFFECTS OF URANIUM FUEL CYCLE ACTIVITIES

6.1 Compliance with 10 CFR 51.51, Uranium Fuel Cycle Environmental Data (NRC Table S-3)

NRC regulations 10 CFR 51.51 provides Table S-3, Table of Uranium Fuel Cycle Environmental Data. The table, reproduced here as Table 6-1, provides the basis for evaluating the contribution to the environmental effects of the following:

- Uranium mining and milling
- Production of uranium hexafluoride
- Isotopic enrichment
- Fuel fabrication
- Reprocessing of irradiated fuel
- Transportation of radioactive materials and
- Management of low-level wastes and high-level wastes related to uranium fuel cycle activities.

Although 10 CFR 51.51 by its language applies to the construction permit stage and not to the operating license stage, Table S-3 is normalized to represent effects from a model 1,000 MWe reactor. Because DNPS reactors are smaller (912 MWe after uprate), Table S-3 reasonably bounds effects from each DNPS reactor. It should be noted that because reprocessing has been discontinued, the portion of Table S-3 effects that are attributable to reprocessing represents an overestimate of the effects of the uranium fuel cycle. The radiological effects presented in Table S-3 are small and are not expected to change due to implementation of the proposed uprate. This analysis is consistent with the generic conclusion reached by the NRC in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants,* specifically Section 6.2 (Ref. 32).

Table 6-1. Table of Uranium Fuel Cycle Environmental Data [Normalized to model light water reactor annual fuel requirement (WASH-1248) or reference reactor year (NUREG-0116)].[a,b]

Environmental Considerations	Total	Maximum effect per annual fuel requirement or reference reactor year of model 1,000 MWe light water reactor (LWR)
NATURAL RESOURCE USE		
Land (acres):		
Temporarily committed[c]	100	
Undisturbed area	79	
Disturbed area	22	Equivalent of 110 MWe coal-fired power plant
Permanently committed	13	
Overburden moved (millions of metric tons)	2.8	Equivalent of 95 MWe coal-fired power plant.
Water (millions of gallons):		
Discharged to air	160	= 2 percent of model 1,000 MWe LWR with cooling tower.
Discharged to water bodies	11,090	
Discharged to ground	127	
Total	11,377	Less than 4 percent of model 1,000 MWe light water reactor with once-through cooling.
Fossil fuel:		
Electrical energy (thousands of MW-hour)	323	Less then 5 percent of model 1,000 MWe light water reactor output.
Equivalent coal (thousands of metric tons)	118	Equivalent to the consumption of a 45 MWe coal-fired power plant.
Natural gas (millions of standard cubic feet)	135	Less than 0.4 percent of model 1,000 MWe output.
Effluents - Chemical (metric tons)		
Gases (including entrainment):[d]		
SO_x	4,400	
NO_x[e]	1,190	Equivalent to emissions from 45 MWe coal-fired plant for a year.
Hydrocarbons	14	
CO	29.6	
Particulates	1,154	
Other gases:		
F	.67	Principally from UF_6 production, enrichment, and reprocessing. Concentration within range of state standards-below level that has effects on human health.
HCL	.014	
Liquids:		
SO^{-}_4	9.9	From enrichment, fuel fabrication, and reprocessing steps.
NO^{-}_3	25.8	Components that constitute a potential for adverse environmental effects are present in dilute concentrations and receive additional
Fluoride	12.9	dilution by receiving bodies of water to levels below permissible standards. The constituents that require dilution and the flow of dilution water are: NH_3-600 cfs, NO_3-20 cfs, Fluoride-70 cfs.

Table 6-1. (Continued).

Environmental Considerations	Total	Maximum effect per annual fuel requirement or reference reactor year of model 1,000 MWe light water reactor (LWR)
Ca^{++}	5.4	
Cl^{-}	8.5	
Na^{+}	12.1	
NH_3	10.0	
Fe	0.4	
Tailings solutions (thousands of metric tons)	240	From mills only-no significant effluents to environment.
Solids	91,000	Principally from mills-no significant effluents to environment
Effluents - Radiological (curies)		
Gases (including entrainment)		
Rn-222		Presently under reconsideration by the Commission.
Ra-226	.02	
Th-230	.02	
Uranium	.034	
Tritium (thousands)	18.1	
C-14	24	
Kr-85 (thousands)	400	
Ru-106	.14	Principally from fuel reprocessing plants.
I-129	1.3	
I-131	.83	
Tc-99		Presently under consideration by the Commission.
Fission products and transuranics	.203	
Liquids:		
Uranium and daughters	2.1	Principally from milling-included tailings liquor and return to ground-no effluents; therefore, no effect on environment
Ra-226	.0034	From UF6 production.
Th-230	.0015	
Th-134	.01	From fuel fabrication plants-concentration 10 percent of 10 CFR 20 for total processing 26 annual fuel requirements for model light water reactor.
Fission and activation products	5.9×10^{-6}	
Solids (buried on site):		
Other than high level (shallow)	11,300	9,100 Curies comes from low level reactor wastes and 1,500 Curies comes from reactor decontamination and decommissioning-buried at land burial facilities. 600 Curies comes from mills-included in tailings returned to ground. Approximately 60 Curies comes from conversion and spent fuel storage. No significant effluent to the environment.
Transuranic and high level waste (deep)	1.1×10	Buried at Federal Repository.
Effluents-thermal (billions of British thermal units)	4,063	<5 percent of model 1,000 megawatt-electric light water reactor.

Table 6-1. (Continued).

Environmental Considerations	Total	Maximum effect per annual fuel requirement or reference reactor year of model 1,000 MWe light water reactor (LWR)
Transportation (person-rem)		
Exposure of workers and general public	2.5	
Occupational exposure (person-rem)	22.6	From reprocessing and waste management.

a. Source: Table S-3, 10 CFR 51.51.
b. In some cases where no entry appears it is clear from the background documents that the matter was addressed and that in effect, the Table should be read as if a specific zero entry had 7been made. However, there are other areas that are not addressed at all in the Table. This Table does not include health effects from the effluents described in the Table, or estimates of releases of radon-222 from the uranium fuel cycle or estimates of technetium-99 released form waste management or reprocessing activities. These issues may be the subject of litigation in the individual licensing proceedings. Data supporting this table are given in the "Environmental Survey of the Uranium Fuel Cycle," WASH-1248, April 1974; the "Environmental Survey of the Reprocessing and Waste Management Portion of the Light Water Reactor Fuel Cycle," NUREG-0116 (Supp. 1 to WASH-1248); the "Public Comments and Task Force Responses Regarding the Environmental Survey of the Reprocessing and Waste Management Portions of the Light Water Reactor Fuel Cycle," NUREG-0216 (Supp. to WASH-1248); and in the record of the final rulemaking pertaining to Uranium Fuel Cycle impacts for Spent Fuel Reprocessing and Radioactive Waste Management Docket RM-50-3. The contributors from reprocessing, waste management, and transportation of wastes are maximized for either of the two fuel cycles (uranium and no recycle). The contribution from transportation of waste excludes transportation of cold fuel to a reactor and of irradiated fuel and radioactive wastes from a reactor, which are considered in Table S-4 of section 51.52. The contribution from the other steps of the fuel cycle are given in columns A-E of Table S-3A of WASH-1248.
c. The contributions to temporarily committed land from reprocessing are not prorated over 30 years since the complete temporary impact accrues regardless of whether the plant services 1 reactor or 57 reactors for 30 years.
d. Estimated effluents based upon combustion of equivalent coal for power generation.
e. 1.2 percent from natural gas use and process.

6.2 Compliance with 10 CFR 51.52, Environmental Effects of Transportation of Fuel and Waste (NRC Table S-4)

NRC regulation 10 CFR 51.52 presents Table S-4 and indicates that, for a reactor that meets specified criteria, Table S-4 summarizes the environmental effects of transporting fuel (both new and spent) and radioactive waste to and from the reactor site on a per-year basis. The table identifies heat and weight per irradiated fuel cask in transit, traffic density, and individual and cumulative dose for workers and the general population under normal conditions. The table also identifies environmental risks from radiological and non-radiological effects under accident conditions. Table S-4 has been reproduced here as Table 6-2.

Table 6-2. Summary Table S-4 - Environmental Impact of Transportation of Fuel and Waste to and from One Light-Water-Cooled Nuclear Power Reactor.[a]

Normal Conditions of Transport

	Environmental impact
Heat (per irradiated fuel cask in transit)	250,000 Btu/hr.
Weight (governed by Federal or state restrictions)	73,000 lbs per truck; 100 tons per cask per rail car
Traffic density:	
Truck	Less than 1 per day
Rail	Less than 3 per month

Exposed population	**Estimated number of persons exposed**	**Range of doses to lexposed individuals[b] (per reactor year)**	**Cumulative does to exposed population (per reactor year)[c]**
Transportation workers	200	0.01 to 300 millirem	4 man-rem
General public			
Onlookers	1,100	0.003 to 1.3 millirem	3 man-rem
Along route	600,000	0.0001 to 0.06 millirem	

Accidents in Transport

	Environmental risk
Radiological effects	Small[d]
Common (nonradiological) causes	1 fatal injury in 100 reactor years; 1 nonfatal injury in 10 reactor years; $475 property damage per reactor year

a. Data supporting this table are given in the Commission's "Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants," WASH-1238, December 1972, and Supp. 1 NUREG-75/038 April 1975. Both documents are available for inspection and copying at the Commission's Public Document Room. 2120 L Street NW, Washington, DC and may be obtained from National Technical Information Service, Springfield, VA 22161. WASH-1238 is available from NTIS at a cost of $5.45 (microfiche, $2.25) and NUREG-75/038 is available at a cost of $3.25 (microfiche, $2.25).

b. The Federal Radiation Council has recommended that the radiation doses from all sources of radiation other than natural background and medical exposures should be limited to 5,000 millirem per year for individuals as a result of occupational exposure and should be limited to 500 millirem per year for individuals in the general population. The dose to individuals due to average natural radiation is about 130 millirem per year.

c. Man-rem is an expression for the summation of whole body doses to individuals in a group. Thus, if each member of a population group of 1,000 people were to receive a dose of 0.001 rem (1 millirem), or if 2 people were to receive a does of 0.5 rem (500 millirem), the total man-rem in each case would be 1 man-rem.

d. Although the environmental risk of radiological effects stemming from transportation accidents is currently incapable of being numerically quantified, the risk remains small regardless of whether it is being applied to a single reactor or a multi-reactor site.

The regulation requires that environmental reports contain either: (a) a statement that the reactor meets specified criteria, in which case its environmental effects would be bound by Table S-4; or (b) further analysis of the environmental effects of transportation of fuel and waste to and from the reactor site. The criteria in Paragraph (a) of 10 CFR 51.52 are not likely to be met by many plants now using higher burnup fuel. The Commission has stated that, in such cases, applicants may incorporate in their analyses the discussion presented in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants,* specifically Section 6.2.3, "Sensitivity to Recent Changes in Fuel Cycle," and Section 6.3, "Transportation." (Ref. 32).

DNPS meets all of the 10 CFR 51.52(a) criteria but the following two:

Plant Parameter	10 CFR 51.52(a) Criteria	Current DNPS Authorization
Uranimum-235 fuel enrichment, percent	Not to exceed 4.0	5.0
Spent fuel average level of irradiation or bumup MWD/MTU	Not to 33,000	60,000

In authorizing ComEd to increase DNPS fuel enrichment from 4 to 5 weight percent Uranium-235 and burnup to 60,000 MWD/MTU, NRC also published an environmental assessment and Finding of No Significant Impact (65 FR 56604, September 19, 2000). The NRC concluded that, although the extended burnup may slightly change the mix of radionuclides that might be released in the event of an accident, there are no significant adverse environmental impacts associated with the proposed action.

The NRC published "Extended Burnup Fuel Use in Commercial LWR's; Environmental Assessment and Finding of No Significant Impact" on February 29, 1988 (53 FR 6040). This generic environmental assessment of extended fuel burnup in light water reactors found that "no significant adverse effects will be generated by increasing the present batch-average burnup level of 33 GWD/MTU to 50 GWD/MTU or above as long as the maximum rod average burnup level of any fuel rod is no greater than 60 GWD/MTU." In addition, the environmental impacts of transportation resulting from the use of higher enrichment fuel and extended irradiation were published and discussed in the NRC assessment entitled, "NRC Assessment of the Environmental Effects of Transportation Resulting from Extended Fuel Enrichment and Irradiation," dated July 7, 1988. That assessment was published in connection with an Environmental Assessment related to the Sheron Harris Nuclear Plant, Unit 1, which was published in the Federal Register on August 11, 1988 (53 FR 30355), as corrected on August 24, 1988 (53 FR 32322). In these assessments, collectively, the NRC concluded that the environmental impacts summarized in Table S-3 of 10 CFR 51.51 and in Table S-4 of 10 CFR 51.52 for a burnup level of 33 GWD/MTU and enrichments up to 4 weight percent Uranium-235 are conservative and bound the corresponding impacts for burnup levels up to 60 GWD/MTU and enrichments up to 5 weight percent Uranium-235. These findings are applicable to the proposed action at DNPS which will limit burnup to 60 GWD/MTU and allow enrichments up to 5 weight percent Uranium-235.

7.0 SUMMARY COMPARISON

This environmental assessment report presents an evaluation of the environmental impacts of the proposed DNPS EPU from 2,527 MWt to 2,957 MWt. The intent of this report is to provide sufficient information for the NRC staff to evaluate the environmental impacts of the proposed EPU in accordance with the requirements of 10 CFR Part 51 "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions."

Socioeconomic Considerations

The proposed EPU does not significantly affect the size of the DNPS work force and does not have a material effect on the labor force required for future plant outages. Local taxing authorities will experience an increase in their property tax bases and significant positive economic benefits will be realized by local and national businesses participating in this proposed EPU. Finally, the communities in the region of influence surrounding the DNPS have benefited and would continue to benefit from local taxes paid by ComEd.

7.1 Non-Radiological Environmental Impacts

Terrestrial Resources

Approval of the proposed EPU would result in minor modifications to current land use, due to the addition of six to eight new mechanical draft cooling tower cells and a small addition to the currently-planned dry cask storage area. The total area affected should be less than one acre of previously disturbed land that currently provides limited wildlife habitat. However, construction activities could result in the displacement of small numbers of animals (e.g., songbirds and small mammals) that forage, feed, nest, or rest in the area. These construction-related impacts would be small, intermittent, and localized. The additional construction would not impact any historic or archaeological areas. However, there would be some minor changes to visual and aesthetic resources.

There are no known Federally threatened or endangered species that exist within the area that would be impacted by land use changes associated with construction activities for the new cooling tower cells. Operation of the 48 currently permitted mechanical draft cooling tower cells has had no observed detrimental impact upon the terrestrial community. Therefore, the addition of new cooling tower cells to ensure thermal compliance should not impact this resource, especially since the cells will only operate during periods of high ambient temperatures.

Transmission Facilities

No changes in operating transmission voltages, onsite transmission equipment or power line rights-of-way are required to implement or support this EPU. However, there will be a slight increase in onsite power required to support the additional eight cooling towers.

EMF created by transmission will be increased as an essentially linear function of power. Power production at DNPS would be less than the capacity at other ComEd stations, where no adverse effects from EMFs are known to have occurred.

Noise

Implementation of the EPU would result in seasonal increases in noise levels during periods of high ambient temperature due to the operation of the new cooling tower cells. Because of their intermittent operation, only marginal increases in noise levels are expected beyond that which has been observed with the operation of the 48 existing cells. Noise levels are not expected beyond those that were considered in the FES.

Cooling Tower Drift, Icing, and Fog

Based on the analysis presented in the FES for the spray modules, the cooling canals, and the cooling pond, the impacts from drift, icing, and fog associated with the cooling water system are no greater than those considered in the FES.

Waste Management

No new waste streams or significant contributions to existing waste streams are expected from implementation of the EPU at DNPS.

Air Effects

Based on an assessment of criteria pollutants, the addition of cooling towers will increase potential PM_{10} emissions, but this increase will be less than regulatory thresholds.

Hydrology Effects

A number of configuration changes have been made in the cooling system at DNPS. These include the construction of a cooling pond and associated cooling canals, the installation of spray modules in the cooling canals, the installation of temporary mechanical draft cooling towers, and finally the installation of permanent mechanical draft cooling towers. All of these changes were documented in the FES, except the mechanical draft cooling towers. Environmental impacts of the installation of the current 48 cooling tower cells were considered through the permitting process, which is the proposed method for the proposed cooling tower cells. Implementation of the proposed EPU will not change the hydrodynamics of the condenser cooling water system intake and discharge amounts; therefore, no associated impacts are expected. In addition, the proposed EPU will not affect groundwater use at DNPS.

ComEd will not seek to change permit requirements for thermal or flow limits or conditions for the proposed EPU. Rather, additional mechanical draft cooling towers will be installed to meet the current thermal limits during critical thermal periods. All cooling towers rely on non-chemical methods for biofouling control. Because flow rates, water sources, and thermal discharges will not change, there will be no incremental impacts associated with these items.

Aquatic Resources Effects

The ecology of the area surrounding the DNPS intake and discharge structures, as well as the onsite cooling pond, have been studied extensively since the late 1960s. A majority of the studies were commissioned by ComEd and relate to the operation of DNPS. ComEd conducted impingement sampling at the traveling intake screens at DNPS from 1977 to 1987. The conclusion of this 10-year study indicated that the number of fish impinged at the station was low and that the fishery in the adjacent river system is not being adversely impacted by operations of DNPS. Implementation of the EPU will not require any changes in the intake structure or intake flows at DNPS; therefore, impacts to fish and shellfish in the early life stages due to the EPU are expected to be insignificant. Discharges after implementation of EPU should not create an additional impact to the resource because discharges will remain within the limits of the existing permit. Finally, no Federally listed threatened or endangered species have been collected in monitoring at DNPS and none are expected if the EPU is approved.

7.2 Radiological Environmental Impacts

Radioactive Waste Streams

A small addition to the currently-planned dry cask storage area is projected for the proposed EPU. At EPU conditions, the solid radioactive waste burial volume is expected to increase approximately 8 percent, the liquid radioactive release volume is not expected to increase and the gaseous radioactive release volume may increase up to 17 percent. The proposed EPU will not introduce any new or different radiological release pathways.

Radiation Levels and Offsite Dose

Offsite dose from liquid and gaseous effluents may increase up to 17 percent. Calculated offsite dose from sky shine will increase proportional to EPU. However, actual offsite dose from sky shine is not expected to increase significantly. At EPU conditions, actual offsite dose will remain significantly less than applicable standards.

Occupational Radiation Exposure

Radiation levels and associated doses are controlled by the ALARA program, which includes facility shielding designs. Normal operation radiation levels will increase by no more than the percentage increase of EPU. This minor increase in radiation levels will not affect radiation zoning or shielding and no new dose reduction programs are scheduled. Therefore, the ALARA program will continue in its current form.

7.3 Environmental Impacts of Accidents

The accidents presented in the FES bound the realistic consequences of accidents that could occur with implementation of the EPU.

7.4 Alternatives to the Proposed Action

Two, approximately 206 MWe alternatives to the DNPS EPU were evaluated. In addition, the "no-action" alternative is available whereby the station continues to operate under the current power levels, environmental impacts remain unchanged, and ComEd develops an alternate energy strategy.

Based on 1998 generation data for the State of Illinois, coal (53.6 percent), nuclear (42.4 percent), gas (3.4 percent), and petroleum (0.6 percent) provided the primary energy sources for generation of electricity. Therefore, based on these and other internal evaluations, ComEd concluded that for incremental increases in generation capacity only pulverized coal- and gas-fired units would be analyzed to meet these needs.

Coal-Fired Generation

ComEd concluded that a coal-fired plant, located at the DNPS, would have moderate impacts on air quality, with the impacts being clearly noticeable. ComEd also believes that, with proper siting and waste management and monitoring practices, waste disposal would also create a moderate, noticeable impact. This is based on the assumption that adequate space can be located within the DNPS footprint for the disposal of waste material. However, permitting and approval for such an operation may be difficult given construction requirements for siting and installing disposal facilities.

Impacts to other resources would consist of impacts to land use, primarily for the storage of coal and ash. Impacts would be mostly visual with some habitat loss. Visual impacts would be consistent with the industrial nature of the area. Socioeconomic impacts would be minimal, due to the proximity to large metropolitan areas. Utilization of the current cooling water system would minimize impacts to aquatic resources and water quality.

Compared to the implementation of the EPU at DNPS, the implementation of the coal-fired alternative for the same amount of electrical power would result in significant environmental impacts to air quality and land use/waste management. In addition to the environmental impacts, implementation of a coal-fired power plant would require a significant amount of additional approvals through the regulatory permitting process as well as obtaining acceptance and approval from the public. DNPS currently has a good relationship with the local and regulatory communities who understand the function of

DNPS. Any change in Station operations that would use both nuclear and coal-fired power plants for generation of electricity could prove difficult. Therefore, implementation of the EPU would result in fewer environmental, community, and regulatory impacts.

Gas-Fired Generation

The gas-fired alternative would also be situated at the existing DNPS site on previously disturbed land, thus reducing construction impacts. The alternative would use the existing cooling water system, thereby reducing aquatic impacts from operation. Land use would be less than for the coal-fired alternative, due to the smaller footprint.

Impacts on air quality would be moderate, but less than impacts from coal-fired generation.

Implementation of the gas-fired alternative would result in almost no waste generation and would produce minor impacts on the surrounding environment. Therefore, ComEd concludes that waste management impacts would be small.

The most significant impact would involve the construction and operation of a new gas pipeline. The pipeline would consist of approximately two miles of 16-inch buried pipe. Primary impacts would be associated with construction activities during the installation of the pipeline. These activities could result in loss of habitat for some terrestrial species as well as impacts due to soil erosion. Additional land use requirements on-site would be significantly less than the coal-fired alternative thus reducing land-dependent ecological, aesthetic, and cultural resource impacts. Operational impacts would not be severe once initial construction completed. Consumptive water use would be about the same, thus minimizing impacts to aquatic resources and water quality. Socioeconomic impacts would be significantly less than the coal-fired alternative due to the short construction period and small work force.

Compared to the implementation of the EPU at DNPS, the implementation of the gas-fired alternative for the same amount of electrical power would result in additional environmental impacts, primarily associated with air quality and the construction of the pipeline. As with the coal-fired alternative, additional regulatory approvals would be required as well as the need to obtain public acceptance and approval. DNPS currently has a good relationship with the local community and a change to dual generation by both nuclear and gas turbines could be difficult. Therefore, implementation of the EPU would have less of an impact on the environment and the regulatory approval process would be streamlined.

7.5 Conclusion

This environmental report demonstrates that, in most cases, implementation of the proposed EPU at DNPS does not involve any new environmental impacts that are significantly different from those presented in the FES or in subsequent referenced documents for the current operating power level. Where environmental impacts differ from those previously presented, these impacts have been shown to be insignificant and well within regulatory and/or permit limits. Outlined below are key conclusions of this environmental assessment report:

Socioeconomic

- The DNPS work force would not be affected. Salary compensation and material costs associated with EPU implementation would result in a positive influence on the economy of the region. Implementation will make ComEd more competitive in the deregulated market.

Non-Radiological

- Up to one acre of previously disturbed land would be required for additional cooling tower cells and dry cask storage. Impacts would be small, intermittent, and localized and would not impact any historic or archaeological resource.
- No changes in transmission voltages or associated facilities; all transmission lines meet or exceed NESC requirements.
- Noise levels would increase seasonally. However, levels are not expected beyond those described in the FES.
- Impacts from cooling tower drift, icing, and fog would be within those described in the FES.
- No new waste streams or significant contributions to existing waste streams and no impacts to groundwater use.
- Thermal compliance of the cooling water system will be achieved by construction and operation of additional mechanical draft cooling towers. Implementation will be through the DNPS NPDES permit.
- No changes in maximum surface water withdrawal or flow through the Station.
- No impacts to Federally listed threatened or endangered species.
- No changes in intake structure design or flow and no changes in entrainment or impingement rates for aquatic organisms.

Radiological

- Dry storage for an additional three to four casks every five years is anticipated.

- Solid radioactive waste burial volume will increase approximately 8 percent, the radioactivity of liquid effluent releases will increase up to 17 percent but the liquid radioactive release volume is not expected to increase. Gaseous releases will increase up to 17 percent.

- Liquid and gaseous effluents will remain within regulatory standards.

- Offsite radioactive dose will remain significantly less than applicable standards.

- Minor increase in occupational radiation exposure is expected. However, no new dose reduction programs are needed and the ALARA program will not change.

Accidents

- Estimated doses as a result of an accident are within the limits presented in the FES and therefore, the realistic consequences are acceptable.

Alternatives

- The coal-fired power plant alternative would have significantly greater impacts on air quality, waste generation, and land use than implementation of the EPU. Emissions of sulfur oxides, nitrogen oxides, carbon monoxide, and particulate matter would all be emitted in excess of major source thresholds and may require emission offsets, credits, or other control techniques. Waste generation would be significant, requiring significant land for disposal of ash and scrubber waste even with an effective recycling program for the waste. Additional land use impacts would be associated with construction of the power block and coal storage area. No changes would be needed for cooling water system and associated impacts would be similar to current use. Visual impacts would result from the additional stacks, boilers, and extensive rail deliveries of coal, but would be consistent with the industrial area. Permitting and approval would be difficult and public acceptance and approval would likewise be difficult.

- The gas-fired alternative would also have significantly greater impacts on air quality and land use compared to the proposed EPU. Air emissions would result in significant emissions of sulfur oxide, nitrogen oxide, carbon monoxide, and particulate matter above source thresholds and would require emission offsets, credits, or other control techniques. Significant impacts and cost (estimated $5M) would be associated with the construction of approximately five miles of gas pipeline. Pipeline construction would result in loss of some wildlife habitat and soil and erosion impacts could occur. Pipeline construction could also impact cultural resources. Permitting and approval would be difficult and public acceptance and approval would likewise be difficult.

Based on the analysis presented in this environmental report, the implementation of the EPU at DNPS is the preferred alternative.

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PLANT MODIFICATIONS REQUIRED TO SUPPORT POWER UPRATE

The following presents an overview of the facility changes necessary to achieve the target electrical power output of 912 MWe.

- An additional 125 VDC cable will be added to the safety-related DC system to provide the additional capacity anticipated at uprated power conditions.
- Various instruments will require scaling/setpoint changes.
- A modification to provide tripping of the 4th condensate pump on a LOCA will be implemented to allow the continued use of the feedwater pumps.
- A fault current limiting arrangement will be implemented to maintain non-safety bus short circuit ratings after a postulated loss of an auxiliary transformer in conjunction with a short circuit.
- A reactor recirculation pump runback on a loss of feedwater flow or the loss of a condensate pump will be implemented to reduce the potential for a scram on reactor low water level and allow continued operation.
- An additional steam line steam resonance compensator card designed to attenuate third order harmonics will be installed in the electro-hydraulic control system to reduce electrical noise in the system.
- A new high-pressure turbine rotor will be installed as a result of the increased steam flow associated with operation at uprated power conditions.
- Turbine cross around relief valve alterations will be performed to ensure that pressure limitations are not exceeded.
- Selected heater drain valve normal drain trim replacements will be performed due to the increase in drain flow.
- Some feedwater heater relief valves will be adjusted or replaced and the heaters will be rerated to compensate for the increased feedwater flow and the associated pressure change.
- Condenser tube staking is planned for the main condensers to provide adequate protection against tube vibration damage at uprated power conditions.
- An additional condensate prefilter will be installed to process the increased flow.
- Additional cooling towers will be installed to ensure that the temperature of the water released to the environment remains within existing limits.

- Various support and piping modifications will be performed due to the increased temperature in torus-attached piping and increased temperature and flow in the main steam and feedwater systems.
- Restriction orifices to the stator water cooling system will be resized to accommodate the increased heat load.
- Modifications to the steam dryer will be performed to reduce moisture carryover.

ATTACHMENT A

Proposed Changes to Operating Licenses and Technical Specifications for
Quad Cities Nuclear Power Station, Units 1 and 2

DESCRIPTION AND SUMMARY SAFETY ANALYSIS

FOR PROPOSED CHANGES

ATTACHMENT A

Proposed Changes to Operating Licenses and Technical Specifications for Quad Cities Nuclear Power Station, Units 1 and 2

DESCRIPTION AND SUMMARY SAFETY ANALYSIS FOR PROPOSED CHANGES

A. SUMMARY OF PROPOSED CHANGES

Pursuant to 10 CFR 50.90, "Application for amendment of license or construction permit," Commonwealth Edison (ComEd) Company is requesting changes to the license and various Technical Specifications (TS) for Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2. The requested changes support an extended power uprate (EPU) for the QCNPS units.

QCNPS is a dual-unit site. Each unit is a General Electric (GE) Boiling Water Reactor (BWR)/3 with a Mark I containment. Because of the significant economic advantages of operating at higher power levels, ComEd is proposing permanent changes to the operating licenses to enable the QCNPS units to be operated at levels up to approximately 17.8 percent above the current rated power level of 2511 megawatts thermal (MWt). This increase corresponds to an uprated power level of 2957 MWt.

The analyses and evaluations supporting the proposed changes directly related to power uprate were completed using the guidelines in GE Topical Report NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (Reference I.1). Certain issues are evaluated generically and have been submitted to the NRC in GE Topical Report NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (Reference I.2). The NRC has approved both of these topical reports, in References I.3 and I.4, respectively.

The planned approach to achieving the higher power level consists of an increase in the core thermal power with a more uniform power distribution and reactor operation primarily along the Maximum Extended Load Line Limit Analysis (MELLLA) rod/flow control lines. The use of the MELLLA domain allows increased thermal power without an increase in core flow. The increased core thermal power will create increased steam flow and require a corresponding increase in the feedwater system flow, which will be achieved by operation of the third feedwater pump and the fourth condensate pump. QCNPS is also proposing to implement the Average Power Range Monitor (APRM) / Rod Block Monitor (RBM) TS (ARTS) power and flow dependent limits to increase plant operational flexibility by updating the fuel thermal limit requirements. This application of ARTS is considered a partial application, as discussed in Section 9.2.1 of Attachment E, since these units are not implementing the hardware changes that are usually installed to the RBM system. The maximum allowable core flow rate does not change as a result of power uprate. In addition, uprated operation will not involve increasing reactor pressure vessel (RPV) dome pressure because the QCNPS units have sufficient pressure control and turbine flow capabilities to control the inlet pressure conditions at the turbine. However, to maintain the GE standard turbine flow margin of three percent, modifications will be made to the high-pressure turbine. Attachment G describes the planned hardware modifications that will maintain adequate performance margins.

The proposed licensed power level of 2957 MWt is used as the basis for the Power Uprate Safety Analysis Report (PUSAR), provided in Attachment E, which supports the proposed changes. Attachment E demonstrates that the QCNPS can safely operate at the proposed licensed power level of 2957 MWt. The proposed licensed power level of 2957 MWt was chosen based on the following considerations. First, feasibility studies showed that a power level of at least 2898 MWt was required to produce an expected output of 912 megawatts electric (MWe), which is the current limitation on the output of the main generator. Second, operation at a power level somewhat greater than 2898 MWt may be required to achieve the 912 MWe output capability of the main generator because the effects of plant efficiencies when operating at the uprated power level can not be fully known prior to implementation. QCNPS expects to operate the Unit 1 and 2 reactors at the power level required to achieve an electrical output of 912 MWe. This power level will vary with the conditions that effect plant thermal efficiency. Finally, future economic conditions may allow upgrade of the main generator and other related modifications to allow a further increase in electric output to take advantage of the proposed power level of 2957 MWt.

QCNPS has submitted a TS amendment request (Reference I.5) for conversion from the Current TS (CTS) to the Improved Technical Specifications (ITS). In anticipation of approval of that request, this request for amendment is based on the format of the ITS. In addition, the affected sections of the CTS are noted.

B. DESCRIPTION OF THE CURRENT REQUIREMENTS

B.1. Operating License Maximum Power Level

Condition 3.A for Unit 1 states, "Commonwealth Edison is authorized to operate Quad Cities Unit No. 1 at power levels not in excess of 2511 megawatts (thermal)."

Condition 3.A for Unit 2 states, "Commonwealth Edison is authorized to operate Quad Cities Unit No. 2 at power levels not in excess of 2511 megawatts (thermal)."

B.2. Operating License Condition on Containment Overpressure

In Reference I.6, QCNPS has requested an amendment to the Units 1 and 2 operating license that would allow changing the Updated Final Safety Analysis Report (UFSAR) to allow credit for containment overpressure as detailed below. This request was needed to assure adequate net positive suction head (NPSH) is available for low-pressure Emergency Core Cooling System (ECCS) pumps following a design basis accident (DBA). In anticipation of approval of this request and because of changes in containment response due to uprated power conditions, changes for this item are included in this request.

Time (seconds)	Containment Pressure (PSIG)
0-210	8.0
210-600	2.5
600-10,000	3.0
10,000-accident end	3.5

B.3. TS Definition of Rated Thermal Power

ITS Section 1.1, "Definitions," defines Rated Thermal Power (RTP) as follows. "RTP shall be a total reactor core heat transfer rate to the reactor coolant of 2511 MWt." RTP is also defined in CTS Section 1.0, "Definitions."

B.4. TS Definition of Fuel Design Limiting Ratio for Centerline Melt

ITS Section 1.1 states that the Fuel Design Limiting Ratio for Centerline Melt (FDLRC) shall be 1.2 times the Linear Heat Generation Rate (LHGR) existing at a given location divided by the product of the transient LHGR (TLHGR) and the fraction of RTP. CTS Section 1.0 also defines FDLRC.

B.5. TS Definition of Maximum Fraction of Limiting Power Density

ITS Section 1.1 states that the Maximum Fraction of Limiting Power Density (MFLPD) shall be the largest value of the fraction of limiting power density (FLPD) in the core. The FLPD shall be the LHGR existing at a given location divided by the specified LHGR limit for that bundle type. CTS Section 1.0 also defines MFLPD.

B.6. TS Section 3.2.4, "Average Power Range Monitor Gain and Setpoint"

ITS Section 3.2.4 requires that when thermal power is ≥ 25%, FDLRC be less than or equal to 1.0 or that each required Average Power Range Monitor (APRM) Flow Biased Neutron Flux - High Function Allowable Value be modified by the lesser of 1/FDLRC or the fraction of rated thermal power (FRTP) /maximum fraction of limiting power density (MFLPD) or that each required APRM gain be adjusted such that the APRM readings are ≥ 100% times the higher of Fraction of RTP (FRTP) times the FDLRC or MFLPD. CTS Section 3.11.B, "Transient Linear Heat Generation Rate," specifies the same requirement.

B.7. TS Section 3.3.1.1, "Reactor Protection System Instrumentation"

Several changes to the Reactor Protection System (RPS) Instrumentation TS are proposed. These include changes to Surveillance Requirements (SRs), Limiting Conditions for Operation (LCO), specified conditions, allowable values and action statements.

TS SR 3.3.1.1.2

ITS SR 3.3.1.1.2 requires verification that the absolute difference between the APRM channels and the calculated power is ≤ 2% RTP plus any gain adjustment required by LCO 3.2.4 while operating at ≥ 25% RTP. This requirement is also identified in CTS Table 4.1.A-1, "Reactor Protection System Instrumentation Surveillance Requirements."

TS SR 3.3.1.1.13

ITS SR 3.3.1.1.13 requires verification that the Turbine Stop Valve (TSV) - Closure and Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when thermal power is ≥ 45% RTP. This requirement is also identified in CTS Table 4.1.A-1.

TS Table 3.3.1.1-1 Function 2.b

ITS Table 3.3.1.1-1, "Reactor Protection System Instrumentation," Function 2.b identifies the allowable values for the APRM Flow Biased Neutron Flux - High Function. For two-loop operation, the allowable value is ≤ 0.58 W + 63.4% RTP and ≤ 122% RTP. For single-loop operation, the allowable value is ≤ 0.58 W + 59.1% RTP and ≤ 118% RTP. A similar requirement is specified in CTS Table 2.2.A-1, "Reactor Protection System Instrumentation Setpoints."

TS Table 3.3.1.1-1 Function 4

ITS Table 3.3.1.1-1, Function 4 identifies the allowable value for the Reactor Vessel Water Level – Low Function. The allowable value is ≥ 11.8 inches. A similar requirement is specified in CTS Table 2.2.A-1.

TS Table 3.3.1.1-1 Function 8

ITS Table 3.3.1.1-1 Function 8 specifies that the TSV - Closure Function is required to be operable when reactor power is ≥ 45% RTP. This requirement is also specified in CTS Table 3.1.A-1, "Reactor Protection System Instrumentation."

TS Table 3.3.1.1-1 Function 9

ITS Table 3.3.1.1-1 Function 9 specifies that the TCV Fast Closure, Trip Oil Pressure - Low Function is required to be operable when reactor power is ≥ 45% RTP. This requirement is also specified in CTS Table 3.1.A-1.

TS Table 3.3.1.1-1 Function 10

ITS Table 3.3.1.1-1 Function 10 specifies that the allowable value for the Turbine Condenser Vacuum – Low scram function be ≥ 21.8 inches HG vacuum. A similar requirement is also specified in CTS Table 2.2.A-1.

TS Section 3.3.1.1 Required Action E.1

ITS Section 3.3.1.1 Action E.1 requires thermal power to be reduced to < 45% RTP as required by Action D.1 and referenced in Table 3.3.1.1-1. This requirement is also specified in CTS Table 3.1.A-1.

B.8. TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

TS Table 3.3.6.1-1 Function 1.d

ITS Table 3.3.6.1-1 provides a listing of the required Primary Containment Isolation Instrumentation. Item 1.d describes the requirements and allowable values for the main steam line (MSL) isolation function for Main Steam Line Flow – High. The allowable value is ≤ 138%. A similar requirement is specified in CTS Table 3.2.A-1, "Isolation Actuation Instrumentation."

TS Table 3.3.6.1-1 Function 2.a

ITS Table 3.3.6.1-1 provides a listing of the required Primary Containment Isolation Instrumentation. Item 2.a describes the requirements and allowable values for the primary containment isolation function on Reactor Vessel Water Level – Low. The allowable value is ≥ 11.8 inches. A similar requirement is specified in CTS Table 3.2.A-1.

TS Table 3.3.6.1-1 Function 5.b

ITS Table 3.3.6.1-1 provides a listing of the required Primary Containment Isolation Instrumentation. Item 5.b describes the requirements and allowable values for the Reactor Water Cleanup (RWCU) System isolation function on Reactor Vessel Water Level – Low. The allowable value is ≥ 11.8 inches. A similar requirement is specified in CTS Table 3.2.A-1.

TS Table 3.3.6.1-1 Function 6.b

ITS Table 3.3.6.1-1 provides a listing of the required Primary Containment Isolation Instrumentation. Item 6.b describes the requirements and allowable values for Reactor Vessel Water Level – Low function for shutdown cooling isolation system isolation. The allowable value is ≥ 11.8 inches. A similar requirement is specified in CTS Table 3.2.A-1.

B.9. TS Section 5.5.12, "Primary Containment Leakage Rate Testing Program"

ITS Section 5.5.12 states that the peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 48 psig. This requirement is also identified in CTS Bases Section B 3/4.7.A, "Primary Containment Integrity."

B.10. TS Section 5.6.5, "Core Operating Limits Report"

ITS Section 5.6.5.a, Item 4 specifies that the core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the Core Operating Limits Report (COLR) including the LHGR and TLHGR limit for Specification 3.2.4. A similar requirement is identified in CTS Section 6.9.A.6.a, "Core Operating Limits Report," although TLHGR is not required to be included in the COLR.

C. BASES FOR THE CURRENT REQUIREMENTS

C.1. Operating License Maximum Power Level

The current operating license and the affected TS sections are based on a RTP of 2511 MWt. The supporting transient and accident analyses justifying operation are also based on this RTP with appropriate margins added, in accordance with regulatory guidance. Limits placed on RTP, Reactor Coolant System (RCS) pressure, RCS temperature and flow ensure that the initial conditions will be met for each of the transients analyzed.

C.2. Operating License Condition on Containment Overpressure

To ensure that there is adequate NPSH to support the operation of the ECCS pumps during DBA conditions, a request for an amendment to the operating license has been submitted to specify the amount of containment overpressure that can be credited in the analyses.

C.3. TS Definition of Rated Thermal Power

The current operating licenses and the affected TS sections are based on a RTP of 2511 MWt. The supporting accident and transient analyses justifying operation were based on this power level with appropriate margin added in accordance with regulatory guidance.

C.4. TS Definition of Fuel Design Limiting Ratio for Centerline Melt

The condition of excessive power peaking can be determined by FDLRC. When FDLRC is greater than 1.0, excessive power peaking exists. Maintaining FDLRC less than or equal to 1.0 ensures that the fuel does not experience centerline melt and protects against fuel cladding 1% plastic strain during Anticipated Operational Occurrences (AOOs) beginning at any power level and terminating at ≤ 122% RTP which corresponds to the APRM Fixed Neutron Flux - High allowable value.

C.5. TS Definition of Maximum Fraction of Limiting Power Density

For GE fuel, the condition of excessive power peaking can be determined calculating MFLPD / FRTP. When MFLPD / FRTP is greater than 1.0, excessive power peaking exists. Maintaining this ratio less than or equal to 1.0 ensures that the fuel does not experience centerline melt during AOOs beginning at any power level and terminating at ≤ 122% RTP which corresponds to the APRM Fixed Neutron Flux - High allowable value.

C.6. TS Section 3.2.4, "Average Power Range Monitor Gain and Setpoint"

This LCO is provided to require the APRM gain or APRM Flow Biased Neutron Flux - High Function Allowable Value to be adjusted when operating under conditions of excessive power peaking. This adjustment is necessary to maintain acceptable margin to the fuel cladding integrity safety limit and the fuel cladding 1% plastic strain limit. When the FDLRC is greater than 1.0 or the ratio of MFLPD / FRTP is greater than 1.0, excessive power peaking exists and the APRM Flow Biased Neutron Flux - High Function allowable value must be adjusted to ensure that the TLHGR limit is not violated for any power distribution. To maintain margins similar to those at RTP conditions, the APRM flow biased allowable value is decreased by a factor of either 1/FDLRC or FRTP/MFLPD. As an alternative, the APRM gain can be increased by FDLRC. Increasing the APRM gain raises the initial APRM reading closer to the flow biased allowable value such that a scram would be received at the same point in a transient as if the allowable value had been reduced. Thus, providing the same degree of protection as reducing the APRM Flow Biased Neutron Flux - High Function allowable value by 1/FDLRC or FRTP/MFLPD.

C.7. TS Section 3.3.1.1, "Reactor Protection System Instrumentation"

TS SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. TS LCO 3.2.4, "APRM Gain and Setpoint," allows the APRMs to be reading greater than actual Thermal Power to compensate for localized power peaking. SR 3.3.1.1.2 verifies that the absolute difference between the APRM channels and the calculated power is ≤ 2% plus any gain adjustment required by LCO 3.2.4.

TS SR 3.3.1.1.13

Since the TSV Closure and TCV Fast Closure, Trip Oil Pressure – Low Functions are capable of being bypassed when reactor power is sufficiently low, this SR ensures that these scram functions will not be bypassed when they may be needed to mitigate a Turbine/Generator (T/G) trip. The associated analyses are based on a reactor power of 45% or approximately 1130 MWt.

TS Table 3.3.1.1-1 Function 2.b

TS Table 3.3.1.1-1 Function 2.b is the Flow Biased Neutron Flux – High setpoint for the APRMs. The purpose of the APRMs is to generate a reactor trip signal on high neutron flux to prevent fuel damage or excessive RCS pressure. During operation, the neutron flux level varies with recirculation drive flow. At lower core flows, this setpoint is reduced as core flow is reduced but is clamped at an upper limit that is equivalent to the APRM Fixed Neutron – High Function allowable value. Because of a lower scram trip setpoint, the APRM Flow Biased Neutron Flux – High Function will initiate a scram before the clamped allowable value is reached during any transient event that occurs at a reduced recirculation flow

TS Table 3.3.1.1-1 Function 4

TS Table 3.3.1.1-1 Function 4 identifies the instrumentation requirements for the Reactor Vessel Water Level – Low Function including the allowable value. A low RPV water level indicates that the capability to cool the fuel may be threatened. Should the RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at a low water level to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level – Low allowable value is selected to ensure that during normal operation, the steam separator skirts are not uncovered to protect available recirculation pump net positive suction head (NPSH) from significant steam ingestion.

TS Table 3.3.1.1-1 Function 8

TS Table 3.3.1.1-1 Function 8 identifies the instrumentation requirements for the TSV – Closure Function including the operating conditions when the function is required to be operable. This function is required to be enabled when RTP is ≥ 45%, which corresponds to a reactor power level of approximately 1130 MWt. This item is identified in the table since this trip is capable of being bypassed at low power levels when the scram function is not needed to mitigate a T/G trip.

TS Table 3.3.1.1-1 Function 9

TS Table 3.3.1.1-1 Function 9 identifies the instrumentation requirements for the TCV Fast Closure, Trip Oil Pressure – Low Function including the operating conditions when the function is required to be operable. This function is required to be enabled when RTP is ≥ 45%, which corresponds to a reactor power level of approximately 1130 MWt. This item is identified in the table since this trip is capable of being bypassed at low power levels when the scram function is not needed to mitigate a T/G trip.

TS Table 3.3.1.1-1 Function 10

The Turbine Condenser Vacuum – Low Function is provided to shut down the reactor and reduce the energy input to the main condenser to help prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. The Turbine Condenser Vacuum – Low Function is the primary scram signal for the loss of condenser vacuum event. For this event, the reactor scram reduces the amount of energy required to be absorbed by the main condenser. It also helps to ensure the MCPR safety limit is not exceeded by reducing the core energy prior to the fast closure of the turbine stop valves. This function helps maintain the main condenser as a heat sink during this event.

TS Section 3.3.1.1 Required Action E.1

If the associated RPS channel is not restored to operable status or placed in trip within the allowed completion time specified in TS Section 3.3.1.1 Required Action E.1, the plant must be placed in a mode or other specified condition in which the LCO does not apply. This LCO is not applicable when reactor power is < 45% RTP.

C.8. TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

TS Table 3.3.6.1-1 Function 1.d

Main Steam Line Flow – High is provided to detect a break of the MSL and to initiate closure of the Main Steam Isolation Valves (MSIVs). If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow – High Function is directly assumed in the analysis of the Main Steam Line Break (MSLB) event. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," and offsite doses do not exceed the 10 CFR 100, "Reactor Site Criteria," limits.

TS Table 3.3.6.1-1 Function 2.a

Primary containment isolation on Reactor Vessel Water Level – Low is provided to isolate the valves whose penetrations communicate with the primary containment to limit the release of fission products when the RPV water level indicates that the capability to cool the fuel may be threatened. The isolation of the primary containment on low RPV level supports actions to ensure that the offsite dose limits of 10 CFR 100 are not exceeded. This isolation function is implicitly assumed in the UFSAR analysis as these leakage paths are assumed to be isolated after a Loss of Coolant Accident (LOCA). The allowable value associated with this function was chosen to be the same as the RPS Reactor Vessel Water Level – Low scram allowable value, since isolation of these valves is not critical to orderly plant shutdown.

TS Table 3.3.6.1-1 Function 5.b

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the RPV occurs to isolate the potential sources of a break. The isolation of the RWCU system on low RPV water level supports actions to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The RWCU isolation function is not directly assumed in the UFSAR safety analyses because the RWCU system line break is bounded by breaks of larger systems.

TS Table 3.3.6.1-1 Function 6.b

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the RPV occurs to isolate the potential sources of a break. The isolation of the RHR shutdown cooling system is not directly assumed in the UFSAR safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the recirculation and main steam lines.

C.9. TS Section 5.5.12, "Primary Containment Leakage Rate Testing Program"

The maximum design pressure for the containment is 62 psig. The safety analysis associated with the postulated design basis LOCA predicts a peak containment pressure of 47 psig. Containment pressure testing is performed at 48 psig to ensure leakage rates are within the criteria established to ensure offsite doses do not exceed the limits of 10 CFR 100.

C.10. TS Section 5.6.5, "Core Operating Limits Report"

Cycle specific parameters, previously located in the TS, have been relocated to the COLR. To support the determination of the FDLRC as required by TS 3.2.4, the LHGR and the TLHGR limits are required to be submitted in the COLR.

D. NEED FOR REVISION OF THE REQUIREMENTS

D.1. Operating License Maximum Power Level

The proposed changes allow an increase in licensed core thermal power from 2511 MWt to 2957 MWt and provide the flexibility to increase the potential electrical output of QCNPS, Units 1 and 2. This power uprate will provide a net increase of approximately 246 MWe in generation to serve commercial and domestic loads on the electrical grid.

D.2. Operating License Condition on Containment Overpressure

As a result of increase power, suppression pool water temperature increases, resulting in a need for additional credit for containment overpressure to maintain adequate NPSH for the ECCS pumps.

D.3. TS Definition of Rated Thermal Power

The proposed changes allow an increase in licensed core thermal power from 2511 MWt to 2957 MWt and provide the flexibility to increase the potential electrical output of the QCNPS, Units 1 and 2. This change is needed to support the change identified in section D.1 of this attachment.

D.4. TS Definition of Fuel Design Limiting Ratio for Centerline Melt

The ARTS power and flow dependent limits provide additional thermal limit restrictions. These allow the removal of the requirement to modify the APRM gain and setpoint based on the FDLRC as discussed in Sections 1.4.1 and 9.2 of Attachment E. The elimination of this requirement also results in the elimination of the requirement to perform the FDLRC calculation.

D.5. TS Definition of Maximum Fraction of Limiting Power Density

The ARTS power and flow dependent limits provide additional thermal limit restrictions. These allow the removal of the requirement to modify the APRM gain and setpoint based on the FDLRC as discussed in Sections 1.4.1 and 9.2 of Attachment E. The elimination of this requirement also results in the elimination of the requirement to perform the MFLPD / FRTP calculation. Consequently, the definition of MFLPD is no longer necessary.

D.6. TS Section 3.2.4, "Average Power Range Monitor Gain and Setpoint"

With the implementation of the ARTS power and flow dependent limits, the additional restrictions that are imposed facilitate the removal of the requirement to modify the APRM gain and setpoint based on the FDLRC or MFLPD / FRTP calculation as discussed in Sections 1.4.1 and 9.2 of Attachment E.

D.7. TS Section 3.3.1.1, "Reactor Protection System Instrumentation"

TS SR 3.3.1.1.2

Since the proposed changes remove TS Section 3.2.4, TS SR 3.3.1.1.2 must be modified to remove the reference to TS Section 3.2.4.

TS SR 3.3.1.1.13

The proposed changes revise the percent RTP at which the TSV – Closure and the TCV Fast Closure, Trip Oil Pressure - Low Functions are verified not to be bypassed. The actual power level at which these trips are required to be operable remains the same. 45% of pre-uprate RTP is essentially the same value as 38.5% of post-uprate RTP as described in Section F.7 of this attachment.

TS Table 3.3.1.1-1 Function 2.b

The proposed changes revise the allowable values for the APRM Flow Biased Neutron Flux – High Function to be consistent with the ELTR (References I.1 and I.2) and the MELLLA. New analytical limits for the flow biased APRM scrams for two-loop operation and single-loop operation have been developed for uprated power conditions.

TS Table 3.3.1.1-1 Function 4

The loss of feedwater (LOFW) transient was analyzed under EPU conditions. Due to increased core heat generation, the RPV water level decreases more rapidly in this transient. A plant modification is being installed to add a recirculation pump runback function to reduce the effects of this water level decrease. Lowering the reactor vessel low water level scram setpoint will increase the potential for recovery before reaching the scram setpoint and thus prevent unnecessary challenges to safety systems and provide additional time for operator action.

TS Table 3.3.1.1-1 Function 8

The proposed changes revise the percent RTP at which the TSV - Closure Function is verified not to be bypassed. The new percent RTP is required to maintain the existing thermal power level at which the function is currently verified. 45% of pre-uprate RTP is essentially the same value as 38.5% of post-uprate RTP as described in Section F.7 of this attachment.

TS Table 3.3.1.1-1 Function 9

The proposed changes revise the percent RTP at which the TCV Fast Closure, Trip Oil Pressure - Low Function is verified not to be bypassed. The new percent RTP is required to maintain the existing thermal power level at which the function is currently verified. 45% of pre-uprate RTP is essentially the same value as 38.5% of post-uprate RTP as described in Section F.7 of this attachment.

TS Table 3.3.1.1-1 Function 10

With the increased heat input due to EPU, the backpressure in the condenser will rise. The plant has an alarm for condenser low vacuum at a nominal value of 25 inches of Hg with a scram allowable value of 21.8 inches of Hg. In conditions of high ambient temperature, the condenser backpressure could potentially exceed the alarm setpoint. To avoid this alarm during normal operations, the alarm setpoint is being changed. To maintain adequate margin between the alarm and the scram, the scram allowable value is being changed to 21.6 inches Hg. The analytical limit for the function remains unchanged.

TS Section 3.3.1.1 Required Action E.1

TS Action E.1 requires that thermal power be reduced to < 45% RTP in the event Condition E is entered. The proposed change revises the TS Action to reduce RTP to < 38.5% of the proposed RTP in the event TS Section 3.3.1.1 Condition E was entered to maintain the actual value of reactor power consistent with the pre-uprate value.

D.8. TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

TS Table 3.3.6.1-1 Function 1.d

The current analytical limit for the Main Steam Line Flow – High Function is 140% of rated steam flow and the allowable value, as stated in Table 3.3.6.1-1 is ≤ 138% of rated steam flow. Changing the percent rated steam flow to the equivalent pressure difference will provide a more meaningful value based on calibration practices.

TS Table 3.3.6.1-1 Function 2.a

This change is associated with TS Table 3.3.1.1-1 Function 4, of Item 6. This item lowers the allowable value of the Reactor Vessel Water Level – Low RPS scram function. To maintain the isolation function at the same level, the allowable value for TS Table 3.3.6.1-1 Function 2.a must also be revised.

TS Table 3.3.6.1-1 Function 5.b

This change is associated with TS Table 3.3.1.1-1 Function 4, of Item 6. This item lowers the allowable value of the Reactor Vessel Water Level – Low RPS scram function. To maintain the isolation function at the same level, the allowable value for TS Table 3.3.6.1-1 Function 2.a must also be revised.

TS Table 3.3.6.1-1 Function 6.b

This change is associated with TS Table 3.3.1.1-1 Function 4, of Item 6. This item lowers the allowable value of the Reactor Vessel Water Level – Low RPS scram function. To maintain the isolation function at the same level, the allowable value for TS Table 3.3.6.1-1 Function 2.a must also be revised.

D.9. TS Section 5.5.12, "Primary Containment Leakage Rate Testing Program"

The analysis of the postulated DBA-LOCA using a more detailed model has identified a lower predicted peak containment pressure compared to the pressure at which the containment is currently tested as identified in the TS. Revising the TS to match the results of the analysis will result in a reduction of burden without affecting the safety analysis.

D.10. TS Section 5.6.5, "Core Operating Limits Report"

The proposed changes remove TS Section 3.2.4 as part of the implementation of the ARTS power and flow dependent limits as described in Item 6 of this attachment. With this change, the inclusion of LHGR and the TLHGR in the COLR for Specification 3.2.4 is no longer necessary.

E. DESCRIPTION OF THE PROPOSED CHANGES

Unless otherwise stated, the affected TS sections are the same for Unit 1 and Unit 2.

E.1. Operating License Maximum Power Level

Condition 3.A for Unit 1 is revised to state, "Commonwealth Edison is authorized to operate Quad Cities Unit No. 1 at power levels not in excess of 2957 megawatts (thermal)."

Condition 3.A for Unit 2 is revised to state, "Commonwealth Edison is authorized to operate Quad Cities Unit No. 2 at power levels not in excess of 2957 megawatts (thermal)."

E.2. Operating License Condition on Containment Overpressure

The allowance for containment overpressure in the license conditions is revised to state, "The license is amended to authorize changing the UFSAR to allow credit for containment overpressure as detailed below, to assure adequate Net Positive Suction Head is available for low pressure Emergency Core Cooling System pumps following a design basis accident."

Time (seconds)	Containment Pressure (PSIG)
0-290	9.5
290-5,000	4.8
5,000-30,000	4.25

E.3. TS Definition of Rated Thermal Power

Section 1.1, "Definitions," Rated Thermal Power (RTP) is revised to reflect the increase from 2511 MWt to 2957 MWt.

E.4. TS Definition of Fuel Design Limiting Ratio for Centerline Melt

The definition of FDLRC in Section 1.1, "Definitions," is deleted.

E.5. TS Definition of Maximum Fraction of Limiting Power Density

The definition of MFLPD in Section 1.1, "Definitions," is deleted.

E.6. TS Section 3.2.4, "Average Power Range Monitor Gain and Setpoint"

TS Section 3.2.4 is deleted.

E.7. TS Section 3.3.1.1, "Reactor Protection System Instrumentation"

TS SR 3.3.1.1.2

The reference to TS Section 3.2.4 is removed so that SR 3.3.1.1.2 states, "Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP."

TS SR 3.3.1.1.13

The thermal power applicability is changed from ≥ 45% to ≥ 38.5% so that SR 3.3.1.1.13 will state, "Verify Turbine Stop Valve – Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 38.5%."

TS Table 3.3.1.1-1 Function 2.b

The allowable value for the APRM Flow Biased Neutron Flux – High Function is changed to 0.56 W + 67.4% and ≤ 122% for two-loop operation and 0.56 W + 63.2% and ≤ 118.4% for single-loop operation as identified in note (b) of Table 3.3.1.1-1.

TS Table 3.3.1.1-1 Function 4

The allowable value for the Reactor Vessel Water Level – Low function is reduced by 8.0 inches from ≥ 11.8 inches to ≥ 3.8 inches.

TS Table 3.3.1.1-1 Function 8

The value in the column labeled "Applicable Modes or Other Specified Conditions" is changed from ≥ 45% to ≥ 38.5%.

TS Table 3.3.1.1-1 Function 9

The value in the column labeled "Applicable Modes or Other Specified Conditions" is changed from ≥ 45% to ≥ 38.5%.

TS Table 3.3.1.1-1 Function 10

The allowable value for the Turbine Condenser Vacuum – Low function is changed from ≥ 21.8 inches Hg vacuum to ≥ 21.6 inches Hg vacuum.

TS Section 3.3.1.1 Required Action E.1

The reference to the thermal power level in Required Action E.1 is changed from < 45% to < 38.5% so that Action E.1 states, "Reduce THERMAL POWER to < 38.5% RTP."

E.8. TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

TS Table 3.3.6.1-1 Function 1.d

The allowable value in TS Table 3.3.6.1-1 Item 1.d is changed from ≤ 138% to ≤ 254.3 psid.

TS Table 3.3.6.1-1 Function 2.a

The allowable value for the Reactor Vessel Water Level – Low function is reduced by 8.0 inches from ≥ 11.8 inches to ≥ 3.8 inches.

TS Table 3.3.6.1-1 Function 5.b

The allowable value for the Reactor Vessel Water Level – Low function is reduced by 8.0 inches from ≥ 11.8 inches to ≥ 3.8 inches.

TS Table 3.3.6.1-1 Function 6.b

The allowable value for the Reactor Vessel Water Level – Low function is reduced by 8.0 inches from ≥ 11.8 inches to ≥ 3.8 inches.

E.9. TS Section 5.5.12, "Primary Containment Leakage Rate Testing Program"

TS 5.5.12.b is revised to reflect a peak calculated primary containment internal pressure for the design basis LOCA, P_a, of 43.9 psig.

E.10. TS Section 5.6.5, "Core Operating Limits Report"

TS Section 5.6.5.a.4 is deleted.

F. SUMMARY SAFETY ANALYSIS OF THE PROPOSED CHANGES

F.1. Operating License Maximum Power Level

The proposed changes increase the RTP from 2511 MWt to 2957 MWt. The detailed safety analyses for the proposed changes are contained in Attachment E. The analyses demonstrate that QCNPS Units 1 and 2 can operate safely with the proposed 17.8 percent increase in maximum core thermal power with a corresponding 19 percent increase in steam flow from the RPV. The analyses also support the required increases of the flow, temperature, and pressure in the supporting systems and components.

QCNPS, Units 1 and 2, are currently licensed for a 100 percent reactor power level of 2511 MWt and most of the current safety analyses are based on this value. However, the ECCS-LOCA and containment safety analyses are based on a power level of 1.02 times the licensed power level as required by Regulatory Guide 1.49, "Power Levels of Water-Cooled Nuclear Power Plants." The proposed uprated power level of 2957 MWt is approximately 17.8 percent greater than the currently licensed thermal power level. The EPU safety analyses are based on a power level of at least 1.02 times the EPU power level, except that some analyses are performed at 100% of uprated power, because the Regulatory Guide 1.49 two percent power factor is already accounted for in the analysis methods.

The analyses presented in Attachment E ensure that the power-dependent margin prescribed by Regulatory Guide 1.49 is maintained. For the safety analyses, NRC-accepted computer codes and calculational techniques are used to demonstrate compliance with the applicable regulatory acceptance criteria. Similarly, factors and margins specified by the application of design code rules is maintained, as are other margin-assuring acceptance criteria used to judge the acceptability of the plant. A list of the computer codes used for the EPU evaluations is provided in Attachment E, Table 1-3, "Computer Codes Used for EPU."

<u>Effects on Plant Systems</u>

Plant systems and components have been verified to be capable of performing their intended design functions at uprated power conditions, with some minor modifications. Modifications to plant components necessary to support power uprate are identified in Attachment G. The review has concluded that operation at power uprate conditions will not affect the reliability of plant equipment.

<u>Fuel Design Considerations</u>

As discussed in Attachment E, Section 2, "Reactor Core and Fuel Performance," EPU increases the power density proportional to the power increase. However, this power density is still within the current operating power density range of most other BWRs. A representative equilibrium cycle core of GE14 fuel was used for the uprate evaluation. NRC approved core design methods were used to analyze core performance at EPU. The cycle specific reload core designs for operation at the uprated power level will take into account the above limits, to ensure acceptable differences between the licensing limits and their corresponding operating values.

At uprated conditions, all fuel and core design limits continue to be met by planned deployment of fuel enrichment and burnable poison management, control rod pattern and/or core flow adjustments.

Thermal-hydraulic design and operating limits ensure an acceptably low probability of boiling transition-induced fuel cladding failure occurring in the core, even for the most severe postulated operational transients. If needed, limits will be placed on fuel average planar linear heat generation rates to meet peak cladding temperature limits for the limiting LOCA.

EPU may result in a small change in fuel burnup, the amount of fuel to be used and isotopic concentrations of the radionuclides in the irradiated fuel relative to the current level of burnup. NRC approved limits for burnup on the fuel designs are not exceeded.

Capability of Makeup Water Sources

EPU with ARTS power and flow dependent limits does not result in an increase or decrease in the available water sources, nor does it change the selection of those assumed to function in the safety analyses. NRC approved methods were used for analyzing the performance of the ECCS during postulated loss of coolant accidents.

Design Basis Accidents

A review of DBAs was performed. DBAs are very low probability hypothetical events whose characteristics and consequences are used in the design of the plant so that the plant can mitigate their consequences to within acceptable regulatory limits. For BWR licensing evaluations, capability is demonstrated for coping with the range of hypothetical pipe break sizes in the largest recirculation, steam, and feedwater lines, a postulated break in one of the ECCS lines, and the most limiting small lines. This break range bounds the full spectrum of large and small, high and low energy line breaks. The evaluation also accommodates a single active equipment failure in addition to the postulated LOCA. Several of the most significant licensing assessments are made using these LOCA ground rules. These assessments are challenges to fuel, challenges to containment, and DBA radiological consequences.

- Challenges To Fuel

  The ECCS is described in UFSAR Section 6.3, "Emergency Core Cooling System." The ECCS performance evaluation, described in Section 4.3, "Emergency Core Cooling System," of Attachment E, was conducted through application of 10 CFR 50 Appendix K, "ECCS Evaluation Models," and demonstrates the continued conformance to the acceptance criteria of 10 CFR 50.46. As mentioned above, a complete spectrum of pipe breaks is investigated from the largest recirculation line down to the most limiting small line break. The effect of the increased power level on the calculated peak cladding temperature (PCT) has been shown to be less than 10 degrees F as discussed in Section 4.3 of Attachment E. The increased PCT consequences for EPU with ARTS power and flow dependent limits remain within the fuel design limits and below the regulatory criteria. Therefore, the ECCS safety margin is not affected by EPU with ARTS power and flow dependent limits.

- Challenges to Containment

The containment analyses are described in UFSAR Section 6.2, "Containment Systems." The primary criteria of merit are the maximum containment pressure calculated during the course of the LOCA and maximum suppression pool temperature for long-term cooling in accordance with 10 CFR 50 Appendix A Criterion 38, "Containment Heat Removal."

Table 4-1, "DBA-LOCA Containment Performance Results," in Attachment E provides the results of the analyses of the plant containment responses to the most severe LOCAs. The effect of EPU on the peak values for containment pressure and temperature confirms the suitability of the plant for operation at EPU. Also, the effects of EPU on the conditions that affect the containment dynamic loads are determined, and the plant is judged satisfactory for EPU operation. The change in short-term containment response is negligible. Because there will be more residual heat with EPU, the containment long-term response increases slightly. However, containment pressures and temperatures remain below their design limits following any DBA, and thus, the containment and its cooling systems are judged to be satisfactory for EPU operation.

- Radiological Consequences

The UFSAR provides the radiological consequences for each DBA. The magnitude of the potential consequences is dependent upon the quantity of fission products released to the environment, the atmospheric dispersion factors and the dose exposure pathways. The atmospheric dispersion factors and the dose exposure pathways do not change. Therefore, the only factor that could influence the magnitude of the consequences is the quantity of activity released to the environment. This quantity is a product of the activity released from the core and reactor coolant and the transport mechanisms between the source region and the effluent release point. The transport mechanisms between the source region and the effluent release point are unchanged by EPU.

As discussed in Section 9.3, "Design Basis Accidents," of Attachment E, the events evaluated are the LOCA, the Main Steam Line Break Accident (MSLBA) outside containment, the Fuel Handling Accident (FHA), the CRDA, the

Instrument Line Break (ILB) and the Offgas Treatment System Component Failure.

The EPU will not change the radiological consequences of a MSLBA outside containment, since the mass and energy releases following a MSLBA remain unaffected by EPU, and the activity released is based on primary coolant activity at TS levels, which is also unaffected by EPU.

The EPU will not change the radiological consequences of an ILB outside containment since the reactor coolant mass release used in the current analysis envelops the post-EPU conditions, and the activity released is based on primary coolant at TS levels which is unaffected by EPU.

The EPU will not change the radiological consequences of an Offgas Treatment System Component Failure since a conservative source term was used in the original analysis.

For the remaining DBAs, the primary parameter of importance is the activity released from the fuel. Because the mechanism of fuel failure is not influenced by EPU, the only parameter of importance is the actual inventory of fission products in the fuel rod. The only parameters affecting fuel inventory are the increase in thermal power, and to some extent, the cycle length.

The DBA, which has historically been limiting from a radiological viewpoint, is the LOCA, for which Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors," or its equivalent, has been applied. For this accident, it is assumed that 100% of the noble gases and 50% of the iodines in the core are released to the primary containment. These release fractions are not influenced by EPU or cycle length. It is, therefore, concluded that the existing LOCA radiological consequences, as a result of EPU, are increased proportional to the increase in power, and, as shown in Section 9.3, the LOCA dose consequences following uprate remain below regulatory guidelines. The EPU LOCA evaluation results include the 2% power uncertainty factor from Regulatory Guide 1.49.

The results of all radiological analyses remain below the 10 CFR 100 guideline values. Therefore, all radiological safety margins are maintained.

Transient Analyses

The effects of plant transients are evaluated in Section 9.1, "Reactor Transients," of Attachment E by investigating a number of disturbances of process variables and malfunctions or failures of equipment according to a scheme of postulating initiating events. These events are primarily evaluated against the Safety Limit Minimum Critical Power Ratio (SLMCPR). The SLMCPR is determined using NRC approved methods. The most limiting transient is slightly more severe when initiated from the uprated power level and results in a slightly larger change in MCPR than when initiated from the current power level. The result is less than a

0.03 change in MCPR. The Operating Limit MCPR is increased appropriately to assure that the SLMCPR is not challenged if any transient is initiated from the uprated power level. In addition, the limiting transients are analyzed for each specific fuel cycle. Licensing acceptance criteria are not exceeded. Therefore, the margin of safety is not affected by EPU.

Environmental Qualification

As discussed in Section 10.3, "Environmental Qualification," of Attachment E, plant equipment and instrumentation has been evaluated against the criteria appropriate for uprate. Significant groups/types of the equipment have been justified for uprate by generic evaluations. The qualification of equipment was resolved by refined radiation calculations, by the use of new test data, by evaluating the operational requirements, or by replacement with qualified equipment.

Fire Protection

A plant-specific evaluation assuming EPU conditions was performed to demonstrate safe shutdown capability in compliance with the requirements of 10 CFR 50 Appendix R, "Fire Protection Program For Nuclear Power Facilities Operating Prior To January 1, 1979." As discussed in Section 6.7.1, "10 CFR 50 Appendix R, Fire Event." of Attachment E, the results demonstrate EPU has no adverse impact on the ability to satisfy the requirements of Appendix R with respect to achieving and maintaining safe shutdown in the event of a fire.

Instrumentation

The control and instrumentation signal ranges and analytical limits for setpoints are evaluated to establish the effects of the changes in various process parameters such as power, neutron flux, steam flow and feedwater flow. Analyses are performed to determine the need for setpoint changes for various functions such as main steam line high flow isolation setpoints. In general, setpoints are changed only to maintain adequate operating margins between plant operating parameters and trip values, and only if satisfactory safety performance is demonstrated.

The instruments and controls that directly interact with or control the reactor are usually considered within the Nuclear Steam Supply System (NSSS). The NSSS process variables, instrument setpoints and Regulatory Guide 1.97, "Instrumentation for Light-water-cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," instrumentation that could be affected by EPU were evaluated. As part of EPU implementation, both the ComEd and GE setpoint methodologies were used to generate the allowable values and nominal trip setpoints related to the analytical limit changes.

TS instrument allowable values and/or setpoints are those sensed variables that initiate protective actions. The determination of instrument allowable values and setpoints is based on plant operating experience and the conservative analytical limits used in specific licensing safety analyses. The settings are selected with sufficient margin to preclude inadvertent initiation of the protective action, while assuring that adequate operating margin is maintained between the system settings and the actual limits.

Increases in the core thermal power and steam flow affect some instrument setpoints, as described in Section 5.3, "Instrument Setpoints," of Attachment E. These setpoints are adjusted to maintain comparable differences between system settings and actual limits, and reviewed to assure that adequate operational flexibility and necessary safety functions are maintained at the extended uprated power level.

F.2. Operating License Condition on Containment Overpressure

EPU increases the reactor decay heat, which increases the heat input to the suppression pool in the event of a LOCA. This increased heat input could potentially increase the peak suppression pool water temperature and containment pressure during the post LOCA short-term and long-term low pressure core injection (LPCI) and core spray (CS) pump operation.

The ECCS NPSH requirements were evaluated for EPU conditions based on the pressure and temperature conditions determined by the containment analysis provided in Section 4.1.1 of Attachment E, flow requirements based on the containment and LOCA analyses provided in Section 4.3 of Attachment E and flow losses, including suction strainer losses, determined using methodology previously reviewed by the NRC.

Calculations show that the available NPSH margin for the CS and LPCI pumps is not reduced during the short-term or long-term period following a DBA-LOCA. As with the original design analysis, the NPSH calculation does take credit for the wetwell airspace pressure during both short-term and long-term periods, as shown in Table 4-2 of Attachment E.

The credit taken for wetwell airspace pressure is adjusted for EPU conditions. This adjustment maintains the same (or greater) margin between the credited pressure profile and the analytical profile and the same (or greater) margin between the credited pressure profile and the pressure required for operation of each pump. For the EPU analysis, the credit taken during short-term and long-term periods is listed in Table 4-2, "NPSH Overpressure Credit," of Attachment E.

Short-term and long-term post-LOCA NPSH concerns are not applicable to the High Pressure Core Injection (HPCI) system. The available NPSH and required NPSH for the HPCI pump are not changed for EPU.

F.3. TS Definition of Rated Thermal Power

Revising the licensed RTP in Section 1.1 is associated with the increase in RTP described in Section F.1 of this attachment.

F.4. TS Definition of Fuel Design Limiting Ratio for Centerline Melt

Deleting the definition of FDLRC in Section 1.1 is associated with the implementation of the ARTS power and flow dependent limits. The definition of FDLRC is associated with the APRM Gain and Setpoint requirement of TS 3.2.4. The removal of this definition is associated with the deletion of TS 3.2.4 as described in Section F.6 of this attachment.

F.5. TS Definition of Maximum Fraction of Limiting Power Density

Deleting the definition of MFLPD in Section 1.1 is associated with the implementation of the ARTS power and flow dependent limits requirement of TS 3.2.4. The removal of this definition is a result of the deletion of TS 3.2.4 as described in Section F.6 of this attachment.

F.6. TS Section 3.2.4, "Average Power Range Monitor Gain and Setpoint"

The proposed change deletes the APRM gain and setpoint requirement. This requirement provides an operational restriction to ensure that the FDLRC does not exceed 1.0. This ensures that an acceptable margin to the fuel cladding integrity safety limit and the fuel cladding 1% strain limit is maintained. As discussed in Section 9.2, "Transient Analysis for ARTS Power and Flow Dependent Limits," of Attachment E, as a result of the implementation of the ARTS power and flow dependent limits, the operational restrictions associated with the APRM Gain and Setpoint adjustments to ensure FDLRC or MFLPD/ FRTP do not exceed 1.0 are bounded and can therefore be eliminated. This application of ARTS is a partial application. These units are not implementing the hardware changes that are usually installed to the RBM system. The hardware changes to the RBM system would typically provide the required protection for an off-rated RWE event. Therefore, off-rated RWE analyses were performed assuming the current RBM configuration with no rod blocks. The results of the off-rated RWE analyses showed that the generic K(P) and the plant specific MCPR(P) limits bound the results of the off-rated RWE event with no rod block. This analysis also supports the RBM operability power level ≥ 30% power. With the RBM inoperable below 30% power, the MCPR safety limit is protected by the MCPR(P) limits below Pbypass.

F.7. TS Section 3.3.1.1, "Reactor Protection System Instrumentation"

TS SR 3.3.1.1.2

The proposed changes remove the reference to the gain adjustment required by TS Section 3.2.4, as the APRM gain and setpoint requirements are superceded by the ARTS power and flow dependent limits related changes including the removal of TS Section 3.2.4. This change is a subset of the changes discussed in Section F.6 of this attachment.

TS SR 3.3.1.1.13

The TSV closure and TCV fast closure scrams can be bypassed when reactor power is sufficiently low, such that the scram function is not needed to mitigate a T/G trip. This power level is the analytical limit for determining the actual trip setpoint, which comes from the turbine first stage pressure (TFSP). The TFSP setpoint is chosen to allow operational margin so that scrams can be avoided, by transferring steam to the turbine bypass system during T/G trips at low power.

Based on the guidelines in Section F.4.2.3 of Reference I.1, the TSV Closure and TCV Fast Closure Scram Bypass analytical limits expressed as a percent of rated thermal power are reduced by the ratio of the power increase such that the absolute power level at which the scram functions are required remains unchanged.

The existing RTP value for which the trip functions are verified not to be bypassed is 45% of 2511 MWt or approximately 1130 MWt. The uprated RTP value for which the trip functions are verified not to be bypassed is 38.5% of 2957 MWt or approximately 1138 MWt. The difference is negligible at approximately 0.1%. As a result, the new analytical limit does not change with respect to absolute thermal power and steam flow, and the setpoint does not change in terms of absolute power. Thus, there is no effect on the transient response. As a result, the same maneuvering range for plant startup is retained. The high pressure turbine rotor modification will change the relationship between turbine first stage pressure and steam flow. Consequently, the scram bypass analytic limit in terms of measured pressure in psia must change to assure that the scram bypass occurs at or below the desired core thermal power and turbine steam flow point. However, the analytic limit as a percent of RTP is not changed by the rotor modification.

TS Table 3.3.1.1-1 Function 2.b

The proposed change revises the APRM flow biased scram equations for reactor recirculation two-loop and single-loop operation. The APRM Flow Biased Neutron Flux – High Function provides protection against transients where thermal power increases slowly, such as the recirculation loop flow controller failure event with increasing flow and the LOFW heating event. This function also protects the fuel cladding integrity by ensuring that the MCPR safety limit is not exceeded. Because of a lower scram trip setpoint, the APRM Flow Biased Neutron Flux - High Function will initiate a scram before the clamped allowable value is reached during any transient event that occurs at a reduced recirculation flow. These changes are necessary to ensure consistent operation with the MELLLA power/flow map as discussed in Section 5.3.5, "Neutron Monitoring System," of Attachment E.

TS Table 3.3.1.1-1 Function 4

The proposed change lowers the allowable value for the Reactor Vessel Water Level – Low Function by 8 inches. The allowable value for the low water level signal is specified so that during normal operation, the seal skirts of the separators and dryers are covered. This is a requirement for plant operation and does not affect the licensing or safety basis of the plant. The allowable value is also specified so that the quantity of coolant following a low water level scram is sufficient for transients involving loss of all normal feedwater flow. Thus, the only transient that could be affected by lowering the scram level setpoint is the LOFW transient. This transient was evaluated to demonstrate that the setpoint change has no adverse effect on the reactor response. Since the LOFW is not a limiting MCPR event, the evaluation was performed primarily to demonstrate that there was no impact on the vessel inventory. In the LOFW event, the reactor water level decreases quickly causing a reactor scram on low water level. Following the scram, the reactor level continues to drop until it reaches the low-low level where the HPCI system and the RCIC system will initiate to maintain the reactor water level. In addition, the reactor vessel low-low water level signal actuates closure of the MSIVs to limit the amount of inventory leaving the vessel. Lowering the low water level scram setpoint by 8 inches would delay the reactor scram for this event by a few seconds. However, since the setpoint for initiating HPCI and RCIC at the low-low water level setpoint remains unchanged, there is no adverse impact on the ability of these systems to maintain vessel inventory, and there is no impact on thermal margins. This is also discussed in Section 5.3.8, "Reactor Water Level Instruments," of Attachment E. Postulated LOCAs inside the containment are the most limiting in terms of peak clad temperature (PCT). This is because the postulated line break outside the containment is isolated before the reactor inventory loss out of the break can result in uncovering the core. Both large and small breaks were reviewed to determine the impact of lowering the analytical limit of the low water level scram by 8 inches. It was concluded that ECCS initiation and containment isolation will not be impacted because the time of scram will not change, since for these breaks, the high drywell pressure signal will occur before the low water level scram signal. Therefore, lowering the scram water level will not change the time of scram for any breaks inside containment and thus will not have a significant impact on ECCS initiation time or PCT.

TS Table 3.3.1.1-1 Function 8

This change is associated with the change in RTP for which the TSV - Closure Function is verified not to be bypassed and is described in Section F.7 in Subsection TS SR 3.3.1.1.13 of this attachment.

TS Table 3.3.1.1-1 Function 9

This change is associated with the change in RTP for which the TCV Fast Closure, Trip Oil Pressure - Low Function is verified not to be bypassed and is described in Section F.7 in Subsection TR SR 3.3.1.1.13 of this attachment.

TS Table 3.3.1.1-1 Function 10

This change involves changing the allowable value for the Turbine Condenser Vacuum – Low scram setpoint. The analytical limit, on which the transient analyses are based, is not affected. Accepted setpoint methodology was used to recalculate the allowable value while maintaining the current analytical limit. Consequently, the transient analyses are unaffected by the change.

TS Section 3.3.1.1 Required Action E.1

This change is associated with the change in RTP for which the TSV - Closure and TCV Fast Closure, Trip Oil Pressure - Low Functions are verified not to be bypassed and is described in Section F.7 in Subsection TS SR 3.3.1.1.13 of this attachment.

F.8. TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

TS Table 3.3.6.1-1 Function 1.d

The proposed change is associated with the units of measure for the allowable value. The proposed change revises the allowable value from units of percent rated steam flow to the pressure difference between the sensors. This change does not alter the allowable value listed in the TS but does result in a change since the allowable value is based on percent of rated steam flow and steam flow increases due to EPU. Since the maximum steam flow does not change due to the flow restrictors, the proposed changes result in a decrease in the difference between the allowable value and the maximum flow. The purpose of the Main Steam Line Flow - High isolation function is to provide protection against pipe breaks in the MSL outside the drywell. For a complete severance of one MSL, steam flow increases almost instantaneously to the maximum rated steam flow as limited by the flow restrictors. Thus, the present and proposed setpoints would be attained virtually at the same time. Therefore, the consequences of a MSL break as evaluated in the UFSAR will remain unchanged with the increase in high flow setpoint. This is also discussed in Section 5.4.3, "Main Steam Line High Flow Isolation," of Attachment E.

TS Table 3.3.6.1-1 Function 2.a

This function is associated with the primary containment isolation on Reactor Vessel Water Level – Low. This change is associated with the proposed change to lower the allowable value of the RPS Reactor Vessel Water Level – Low scram function described in Section F.6 in Subsection TS Table 3.3.1.1-1 Function 4 of this attachment. The purpose of containment isolation is to minimize the potential inventory loss across the containment boundary and to prevent offsite radiation doses from exceeding 10 CFR 100 limits during a postulated LOCA. For LOCAs inside primary containment, the high drywell pressure signal will be the first signal to initiate primary containment isolation. The radiological source term is a function of the power level and the resulting fission product noble gases and iodines in the core are conservatively assumed to be immediately released following a LOCA. Thus, neither the amount of fission products released to the containment nor the time at which the containment isolates are dependent on the low water level containment isolation. For LOCAs outside containment, the main steam line break is the limiting event. This event is mitigated by the containment isolation that occurs on high steam flow or low steam line pressure. Therefore, this change does not affect the limiting event. However, small steam breaks outside containment that do not cause the isolation on high steam flow or low steamline pressure would rely on the low RPV water level isolation. Lowering of the low water level by 8 inches would not cause the mass release from the small steam break to become greater than the mass release from the large steamline break. Therefore, the delay of this isolation signal for a few seconds will not affect the ability of the containment isolation valves to perform their intended functions.

TS Table 3.3.6.1-1 Function 5.b

This function is associated with the isolation of the RWCU system on Reactor Vessel Water Level – Low. This change is associated with the proposed change to lower the allowable value of the RPS Reactor Vessel Water Level – Low scram function described in Section F.6 in Subsection TS Table 3.3.1.1-1 Function 4 of this attachment. The RWCU isolation is not directly assumed in the UFSAR safety analyses because the RWCU system line break is bounded by breaks of larger systems. This is still the case under EPU conditions. Therefore, the delay of this isolation signal for a few seconds will not affect the ability of the containment isolation valves to perform their intended functions.

TS Table 3.3.6.1-1 Function 6.b

This function is associated with the isolation of the shutdown cooling system and is only required to be operable in modes 3, 4 and 5. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. This function is not directly assumed in the safety analyses because a break in the shutdown cooling system is bounded by a break in the recirculation and main steam lines. This allowable value is being changed since it is the same as the allowable value for the RPS Reactor Vessel Water Level – Low scram function. The summary safety analysis associated with that change is described in Section F.6 in Subsection TS Table 3.3.1.1-1 Function 4 of this attachment.

F.9. TS Section 5.5.12, "Primary Containment Leakage Rate Testing Program"

As discussed in Section 4.1, "Containment System Performance," of Attachment E, the peak drywell pressure occurs during the short-term DBA-LOCA. The short-term DBA-LOCA analysis covers the blowdown period during which the maximum drywell pressures and differential pressures between the drywell and wetwell occur. The analysis is performed at 102% of the EPU power level, with the break flow calculated using a more detailed model that has been previously approved by the NRC. When analyzed at pre-uprate conditions using the more detailed model, the peak containment pressure is predicted to be 42.8 psig, whereas the previous model predicted a peak containment pressure of 47 psig. The EPU has a relatively insignificant impact on peak drywell pressure. The analysis predicts an increase of 1.1 psig over the pre-uprate value. The predicted peak pressure at uprated conditions of 43.9 psig is well below the maximum allowable internal pressure of 62 psig.

F.10. TS Section 5.6.5, "Core Operating Limits Report"

The proposed change deletes TS Section 5.6.5.a.4 entirely because TS Section 3.2.4 is deleted entirely. TS Section 5.6.5.a.4 requires the LHGR and the TLHGR to be included in the COLR in support of TS 3.2.4. With the removal of TS 3.2.4 as discussed in Section F.6 of this attachment, this requirement is no longer necessary. Since the TLHGR is used to calculate the FDLRC and the FDLRC calculation is removed as part of the removal of TS 3.2.4, inclusion of the TLHGR in the COLR is no longer necessary. The LHGR will continue to be included in the COLR in support of TS Section 5.6.5.a.3.

G. IMPACT ON PREVIOUS SUBMITTALS

All submittals currently under review by the NRC were evaluated to determine the impact of this submittal. By letter dated March 3, 2000, QCNPS has submitted a TS Amendment request for conversion to the ITS (Reference I.5). In anticipation of approval, this request for amendment is based on the format of the ITS. In letter dated January 29, 1999 (Reference I.6), QCNPS has requested an amendment to the operating license for both Units 1 and 2 that would allow changing the UFSAR to specify the amount of containment overpressure that can be credited in the analyses. This request was needed to assure adequate net positive suction head (NPSH) is available for low-pressure Emergency Core Cooling System (ECCS) pumps following a design basis accident (DBA). Because of changes in containment response due to uprated power conditions, additional changes to the request are required.

No other submittals currently under review by the NRC are affected by the information presented in this license amendment request.

H. SCHEDULE REQUIREMENTS

ComEd plans to fully implement the uprated power conditions for Unit 1 during the refueling outage scheduled to begin October 2002 and for Unit 2 during the refueling outage scheduled to begin February 2002. Therefore, ComEd requests that if found acceptable, the proposed changes be approved by January 15, 2002.

I. REFERENCES

1. GE Licensing Topical Report NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," February 1999, Proprietary, ELTR1

2. GE Licensing Topical Report NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," February 2000, Proprietary, ELTR2

3. NRC Letter, "Staff Position Concerning General Electric Boiling-Water Reactor Extended Power Uprate Program (TAC No. M91680)," February 8, 1996

4. NRC Letter, "Staff Safety Evaluation of General Electric Boiling Water Reactor (BWR) Extended Power Uprate Generic Analyses (TAC M95087)," September 14, 1998

5. Letter from R. M. Krich (Commonwealth Edison Company) to U.S. NRC, "Request for Technical Specifications Changes for Dresden Nuclear Power Station, Units 2 and 3, LaSalle County Station, Units 1 and 2, and Quad Cities Nuclear Power Station, Units 1 and 2, to Implement Improved Standard Technical Specifications," dated March 3, 2000

6. Letter from J. P. Dimmette, Jr. (ComEd) to USNRC, "Request for License Amendment Pursuant to 10 CFR 50.90 Credit for Containment Overpressure," dated January 29, 1999

ATTACHMENT B

Proposed Changes to Operating Licenses and Technical Specifications for Quad Cities Nuclear Power Station, Units 1 and 2

MARKED-UP TS PAGES FOR PROPOSED CHANGES

The marked-up Technical Specifications are provided in the following pages. The marked-up bases pages are also provided for reference.

REVISED LICENSE PAGES

Page 3 - Condition 3.A (Unit 1)
Page 2 – Condition 3.A (Unit 2)

REVISED PAGES

1.1-3
1.1-4
1.1-5
3.2.4-1
3.2.4-2
3.3.1.1-2
3.3.1.1-3
3.3.1.1-5
3.3.1.1-7
3.3.1.1-8
3.3.1.1-9
3.3.6.1-5
3.3.6.1-7
5.5-12
5.6-3

Note: There are no changes on this page. This page is provided for continuity only.

NOTE: This is a facsimile of the Quad Cities Operating License DPR-29 It will be updated whenever amendments are issued. <u>It is currently updated through Amendment 195 dated February 4, 2000.</u>

<u>DOCKET NO. 50-254</u>

<u>COMMONWEALTH EDISON COMPANY</u>

<u>AND</u>

<u>MIDAMERICAN ENERGY COMPANY</u>

<u>FACILITY OPERATING LICENSE</u>

The Atomic Energy Commission (the Commission) has found that:

a. The application, as amended, complies with the requirements of the Atomic Energy Act of 1954, as amended (the Act), and the regulations of the Commission set forth in 10 CFR Chapter 1;

b. Construction of the Quad Cities Nuclear Power Station Unit 1 (the facility) has been substantially completed in conformity with Provisional Construction Permit No. CPPR-23 and the application, as amended, the provisions of the Act, and the rules and regulations of the Commission set forth in 10 CFR Chapter 1;

c. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

d. There is reasonable assurance (i) that the activities authorized by this operating license, as amended, can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

e. The Commonwealth Edison Company and the MidAmerican Energy Company are technically and financially qualified to engage in the activities authorized by this operating license, as amended, in accordance with the rules and regulations of the Commission;

f. The Commonwealth Edison Company and the MidAmerican Energy Company have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements";

g. The issuance of this amended license will not be inimical to the common defense and security or to the health and safety of the public, and

h. In accordance with the requirements of Appendix D of 10 CFR Part 50, Facility Operating License No. DPR-29 should be amended to authorized full-power operation subject to the conditions for protection of the environment referred to in paragraph 8 of the Summary and Conclusions section of the Final Environmental Statement dated September 1972 and set forth in the Technical Specifications incorporated herein.

Facility Operating License No. DPR-29, as amended, issued to Commonwealth Edison Company (Commonwealth Edison) and MidAmerican Energy Company is hereby amended in its entirety to read as follows:

1. This license applies to the Quad Cities Nuclear Power Station Unit 1, a single cycle, boiling, light-water reactor, and electric generating equipment (the facility) which is jointly owned by Commonwealth Edison and MidAmerican Energy. The facility is part of the Quad Cities Nuclear Power Station located in Rock Island County, Illinois, and is described in the application for construction permit and facility license dated May 31, 1966, and subsequent amendments thereto, including the application amendment dated August 30, 1968, as amended, for the full-power license and the Environmental Report dated November 12, 1970, as supplemented November 1, 1971, and thereafter.

2. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses Commonwealth Edison and MidAmerican Energy, pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities", to own the facility, as their interests appear in the application, and hereby licenses Commonwealth Edison, acting for itself and as agent for MidAmerican Energy:

   A. Pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities", to possess, use, and operate the facility as a utilization facility at the location designated in the application, in accordance with the procedures and limitations described in the application and in this license;

Am. 38
02/03/77

   B. Pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any special time nuclear materials, not including plutonium, as reactor fuel, in accordance with the limitations for storage and amounts required for operation as described in the Final Safety Analysis Report, as supplemented and amended;

Am. 38
02/03/77

   C. Pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time up to 8 kilograms of plutonium for use in connection with operation of the facility;

Am. 38
02/03/77

   D. Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess and use at any time, any byproduct, source and special nuclear materials as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts required;

Am. 38
02/03/77

   E. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source or special nuclear materials without restriction to chemical or physical form, for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

Am. 43
01/30/78

   F. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of Quad Cities Nuclear Power Station, Unit Nos. 1 and 2.

3. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

AM. 188
6/25/99

A. Maximum Power Level
Commonwealth Edison is authorized to operate Quad Cities Unit No. 1 at power levels not in excess of ~~2511~~ megawatts (thermal).
2957

Am. 195
2/04/00

B. Technical Specifications
The Technical Specifications contained in Appendices A and B as revised through **Amendment No. 195** are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

Am. 150
11/3/94

C. The licensee shall maintain the commitments made in response to the March 14, 1983, NUREG-0737 Order, subject to the following provision:

The licensee may make changes to commitments made in response to the March 14, 1983, NUREG-0737 Order without prior approval of the Commission as long as the change would be permitted without NRC approval, pursuant to the requirements of 10 CFR 50.59. Consistent with this regulation, if the change results in an Unreviewed Safety Question, a license amendment shall be submitted to the NRC staff for review and approval prior to implementation of the change.

Am. 188
06/25/99

D. Equalizer Valve Restriction
Three of the four valves in the equalizer piping between the recirculation loops shall be closed at all times during reactor operation with one bypass valve open to allow for thermal expansion of water.

Am. 108
06/09/88

E. Physical Protection
The licensee shall fully implement and maintain in effect all provisions of the Commission approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions of 10 CFR 73.55 (51 FR 27817 and 27822), and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). These plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Quad Cities Nuclear Power Station Security Plan," with revisions submitted through January 14, 1988; "Quad Cities Nuclear Power Station Security Personnel Training and Qualification Plan," with revisions submitted through October 29, 1987; and "Quad Cities Nuclear Power Station Safeguards Contingency Plan," with revisions submitted through February 16, 1984. Changes made in accordance with 10 CFR 73.55, shall be implemented in accordance with the schedule set forth therein.

Am. 141
05/13/93

F. Commonwealth Edison Company shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report for the facility and as approved in the Safety Evaluation Reports dated July 27, 1979 with supplements dated November 5,1980, and February 12, 1981; December 30, 1982; December 1, 1987 with supplement dated April 20, 1988; December 11, 1987 with supplement dated July 21, 1988; and February 25, 1991, subject to the following provision:

The license may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

Note: There are no changes on this page. This page is provided for continuity only.
NOTE: This is a facsimile of the Quad Cities Operating License DPR-30. It will be updated whenever amendments are issued. <u>It is currently updated through Amendment 188 dated December 21, 1999.</u>

DOCKET NO. 50-265

COMMONWEALTH EDISON COMPANY

AND

MIDAMERICAN ENERGY COMPANY

FACILITY OPERATING LICENSE

The Atomic Energy Commission (the Commission) has found that:

a. The application, as amended, complies with the requirements of the Atomic Energy Act of 1954, as amended (the Act), and the regulations of the Commission set forth in 10 CFR Chapter 1;

b. Construction of the Quad Cities Nuclear Power Station Unit 2 (the facility) has been substantially completed in conformity with Provisional Construction Permit No. CPPR-24 and the application, as amended, the provisions of the Act, and the rules and regulations of the Commission set forth in 10 CFR Chapter 1;

c. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

d. There is reasonable assurance (i) that the activities authorized by this operating license, as amended, can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

e. The Commonwealth Edison Company and the MidAmerican Energy Company are technically and financially qualified to engage in the activities authorized by this operating license, as amended, in accordance with the rules and regulations of the Commission;

f. The Commonwealth Edison Company and the MidAmerican Energy Company have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements";

g. The issuance of this amended license will not be inimical to the common defense and security or to the health and safety of the public, and

h. In accordance with the requirements of Appendix D of 10 CFR Part 50, Facility Operating License No. DPR-30 should be amended to authorized full-power operation subject to the conditions for protection of the environment referred to in paragraph 8 of the Summary and Conclusions section of the Final Environmental Statement dated September 1972 and set forth in the Technical Specifications incorporated herein.

Facility Operating License No. DPR-30, as amended, issued to Commonwealth Edison Company (Commonwealth Edison) and MidAmerican Energy Company is hereby amended in its entirety to read as follows:

1. This license applies to the Quad Cities Nuclear Power Station Unit 2, a single cycle, boiling, light-water reactor, and electric generating equipment (the facility) which is jointly owned by Commonwealth Edison and MidAmerican Energy. The facility is part of the Quad Cities Nuclear Power Station located in Rock Island County, Illinois, and is described in the application for construction permit and facility license dated May 31, 1966, and subsequent amendments thereto, including the application amendment dated August 30, 1968, as amended, for the full-power license and the Environmental Report dated November 12, 1970, as supplemented November 1, 1971, and thereafter.

2. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses Commonwealth Edison and MidAmerican Energy, pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities", to own the facility, as their interests appear in the application, and hereby licenses Commonwealth Edison, acting for itself and as agent for MidAmerican Energy:

   A. Pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities", to possess, use, and operate the facility as a utilization facility at the location designated in the application, in accordance with the procedures and limitations described in the application and in this license;

   B. Pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear materials, not including plutonium, as reactor fuel,
Am. 36 in accordance with the limitations for storage and amounts required for
02/03/77 operation as described in the Final Safety Analysis Report, as supplemented and amended;

Am. 36 C. Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess and use at
02/03/77 any time, any byproduct, source and special nuclear materials as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts required;

Am. 36 D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive possess
02/03/77 and use in amounts as required any byproduct, source or special nuclear materials without restriction to chemical or physical form, for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

Am. 41 E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not
01/30/78 separate, such byproduct and special nuclear materials as may be produced by the operation of Quad Cities Nuclear Power Station, Unit Nos. 1 and 2.

3. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

   A. <u>Maximum Power Level</u>
   Commonwealth Edison is authorized to operate Quad Cities Unit No. 2 at power levels not in excess of ~~2511~~ megawatts (thermal).
   2957

Am. 191 <u>Technical Specifications</u>
2/04/00 The Technical Specifications contained in Appendices A and B as revised through **Amendment No. 191** are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

1.1 Definitions

DOSE EQUIVALENT I-131 (continued)	conversion factors used for this calculation shall be those listed in Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites;" Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977; or ICRP 30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity."
~~FUEL DESIGN LIMITING RATIO FOR CENTERLINE MELT (FDLRC)~~	~~The FDLRC shall be 1.2 times the LHGR existing at a given location divided by the product of the transient LHGR limit and the fraction of RTP.~~
LEAKAGE	LEAKAGE shall be: a. <u>Identified LEAKAGE</u> 1. LEAKAGE into the drywell, such as that from pump seals or valve packing, that is captured and conducted to a sump or collecting tank; or 2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; b. <u>Unidentified LEAKAGE</u> All LEAKAGE into the drywell that is not identified LEAKAGE; c. <u>Total LEAKAGE</u> Sum of the identified and unidentified LEAKAGE; and d. <u>Pressure Boundary LEAKAGE</u> LEAKAGE through a nonisolable fault in a Reactor Coolant System (RCS) component body, pipe wall, or vessel wall.

(continued)

1.1 Definitions (continued)

LINEAR HEAT GENERATION RATE (LHGR)	The LHGR shall be the heat generation rate per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components required for OPERABILITY of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.
~~MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)~~	~~The MFLPD shall be the largest value of the fraction of limiting power density (FLPD) in the core. The FLPD shall be the LHGR existing at a given location divided by the specified LHGR limit for that bundle type.~~
MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE – OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that

(continued)

1.1 Definitions

OPERABLE – OPERABILITY (continued)	are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~2511~~ 2957 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from the opening of the sensor contact until the opening of the trip actuator. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are

(continued)

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Scram Times

BASES

BACKGROUND

The scram function of the Control Rod Drive (CRD) System controls reactivity changes during anticipated operational occurrences to ensure that specified acceptable fuel design limits are not exceeded (Ref. 1). The control rods are scrammed by positive means using hydraulic pressure exerted on the CRD piston.

When a scram signal is initiated, control air is vented from the scram valves, allowing them to open by spring action. Opening the exhaust valve reduces the pressure above the main drive piston to atmospheric pressure, and opening the inlet valve applies the accumulator or reactor pressure to the bottom of the piston. Since the notches in the index tube are tapered on the lower edge, the collet fingers are forced open by cam action, allowing the index tube to move upward without restriction because of the high differential pressure across the piston. As the drive moves upward and the accumulator pressure reduces below the reactor pressure, a ball check valve opens, letting the reactor pressure complete the scram action. If the reactor pressure is low, such as during startup, the accumulator will fully insert the control rod in the required time without assistance from reactor pressure.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in Reference 2. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. The resulting negative scram reactivity forms the basis for the determination of plant thermal limits (e.g., the MCPR). Other distributions of scram times (e.g., several control rods scramming slower than the average time with several control rods scramming faster than the average time) can also provide sufficient scram reactivity. Surveillance of each individual control rod's scram time ensures the scram reactivity assumed in the DBA and transient analyses can be met.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The scram function of the CRD System protects the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," ~~and LCO 3.2.4, Average Power Range Monitor (APRM) Gain and Setpoint"),~~ which ensure that no fuel damage will occur if these limits are not exceeded. At ≥ 800 psig, the scram function is designed to insert negative reactivity at a rate fast enough to prevent the actual MCPR from becoming less than the MCPR SL, during the analyzed limiting power transient. Below 800 psig, the scram function is assumed to perform during the control rod drop accident (Ref. 3) and, therefore, also provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control"). For the reactor vessel overpressure protection analysis, the scram function, along with the safety/relief valves, ensure that the peak vessel pressure is maintained within the applicable ASME Code limits.

Control rod scram times satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The scram times specified in Table 3.1.4-1 are required to ensure that the scram reactivity assumed in the DBA and transient analysis is met (Ref. 4). To account for single failures and "slow" scramming control rods, the scram times specified in Table 3.1.4-1 are faster than those assumed in the design basis analysis. The scram times have a margin that allows up to approximately 7% of the control rods (e.g., 177 x 7% ≈ 12) to have scram times exceeding the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3, "Control Rod OPERABILITY") and an additional control rod failing to scram per the single failure criterion. The scram times are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram times are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the index tube passes a specific location and then opens

(continued)

Note: There are no changes on this page. This page is provided for continuity only.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods are expected to avoid boiling transition if the limit is not violated (refer to the Bases for SL 2.1.1.2). The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experienced boiling transition (Ref. 1), the critical power at which boiling transition is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in References 2, 3, 4, 5, 6, 7, 8, and 9. To ensure that the MCPR SL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in critical power ratio (CPR). The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (ΔCPR). When the largest ΔCPR is added to the MCPR SL, the required operating limit MCPR is obtained.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow state ($MCPR_f$) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency as identified in UFSAR, Chapter 15 (Ref. 5).

Replace with INSERT B 3.2.2-2

~~Flow dependent MCPR limits are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 8) and a multichannel thermal hydraulic code (Ref. 9) to analyze slow flow runout transients on a cycle-specific basis. For core flows less than rated, the established MCPR operating limit is adjusted to provide protection of the MCPR SL in the event of an uncontrolled recirculation flow increase to the physical limit of the pump. Protection is provided for manual and automatic flow control by applying appropriate flow dependent MCPR operating limits. The MCPR operating limit for a given flow state is the greater of the rated conditions MCPR operating limit or the flow dependent MCPR operating limit. For automatic flow control, in addition to protecting the MCPR SL during the flow run-up event, protection is provided by the flow dependent MCPR operating limit to prevent exceeding the rated flow MCPR operating limit during an automatic flow increase to rated core flow. The operating limit is dependent on the maximum core flow limiter setting in the Recirculation Flow Control System.~~

The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the appropriate $MCPR_f$ or the rated condition MCPR limit.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 25% RTP, the reactor is operating at a low recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting

(continued)

INSERT B 3.2.2-2

Flow-dependent MPCR limits, MCPR(F), ensure that the Safety Limit MCPR (SLMCPR) is not violated during recirculation flow events. The design basis flow increase event is a slow-flow power increase event which is not terminated by scram, but which stabilizes at a new core power corresponding to the maximum possible core flow. Flow runout events are simulated along a constant xenon flow control line assuming a quasi steady-state plant heat balance. The ARTS-based MCPR(F) limit is specified as an absolute value and is generic and cycle-independent. The operating limit is dependent on the maximum core flow limiter setting in the Recirculation Flow Control System.

Above the power at which the scram is bypassed, bounding power-dependent trend functions have been developed. These trend functions, K(P), are used as multipliers to the rated MCPR operating limits to obtain the power-dependent MCPR limits, MCPR(P). Below the power at which the scram is automatically bypassed, the MCPR(P) limits are actual absolute Operating Limit MCPR (OLMCPR) values. The power dependent limits are established to protect the core from plant transients other than core flow increases, including pressurization and local control rod withdrawal events.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. Limits on LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (AOOs). Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure, or inability to cool the fuel does not occur during the normal operations and anticipated operating conditions identified in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 1 and 2. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20, 50, and 100. A mechanism that could cause fuel damage during normal operations and operational transients and that is considered in fuel evaluations is a rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Ref. 3).

Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGRs up to the operating limit specified in the COLR. The analysis also includes allowances for short term transient excursions above the operating limit while still remaining within the AOO limits, plus an allowance for densification power spiking.

INSERT B 3.2.3-1 →

The LHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

INSERT B 3.2.3-1

Flow-dependent LHGR limits, LHGRFAC(F), were designed to assure adherence to all fuel thermal-mechanical design bases in the event of slow recirculation flow runout event. From the bounding overpowers, the LHGRFAC(F) limits were derived such that during these events, the peak transient linear heat generation rate would not exceed fuel mechanical limits. The flow-dependent LHGR limits are generic, cycle-independent and are specified in terms of multipliers, LHGRFAC(F), to be applied to the rated LHGR values.

Power-dependent LHGR limits, expressed in terms of a LHGR multiplier, LHGRFAC(P), are substituted to assure adherence to the fuel thermal-mechanical design bases at reduced power conditions. The power-dependent LHGRFAC(P) limits are generated using the same database as used to determine the MCPR multiplier (K(P)). For GE fuel designs, both incipient centerline melting of the fuel and plastic strain of the cladding are considered in determining the power-dependent LHGR limit although the limiting criterion is generally incipient centerline melting. Appropriate LHGRFAC(P) limits are selected based on plant-specific transient analyses. These limits are derived to assure that peak transient LHGR for any transient is not increased above the fuel design bases.

3.2 POWER DISTRIBUTION LIMITS

3.2.4 Average Power Range Monitor (APRM) Gain and Setpoint

LCO 3.2.4

a. FDLRC and the ratio of MFLPD to Fraction of RTP (FRTP) shall be less than or equal to 1.0; or

b. Each required APRM Flow Biased Neutron Flux — High Function Allowable Value shall be modified by the lesser of 1/FDLRC or FRTP/MFLPD; or

c. Each required APRM gain shall be adjusted such that the APRM readings are ≥ 100% times the higher of FRTP times FDLRC or of MFLPD.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	6 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	------------------NOTE------------------ Not required to be met if SR 3.2.4.2 is satisfied for LCO 3.2.4.b or LCO 3.2.4.c requirements. --------------------------------------- Verify FDLRC and the ratio of MFLPD to FRTP are within limits.	Once within 12 hours after ≥ 25% RTP <u>AND</u> 24 hours thereafter
SR 3.2.4.2	------------------NOTE------------------ Not required to be met if SR 3.2.4.1 is satisfied for LCO 3.2.4.a requirements. --------------------------------------- Verify each required: a. APRM Flow Biased Neutron Flux—High Function Allowable Value is modified by less than or equal to the lesser of 1/FDLRC or FRTP/MFLPD; or b. APRM gain is adjusted such that the APRM reading is ≥ 100% times the higher of FRTP times FDLRC or of MFLPD.	12 hours

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 Average Power Range Monitor (APRM) Gain and Setpoint

BASES

BACKGROUND

The OPERABILITY of the APRMs and their setpoints is an initial condition of all safety analyses that assume rod insertion upon reactor scram. Applicable general design criteria are discussed in UFSAR, Sections 3.1.2.1, 3.1.3.2, 3.1.3.4, 3.1.3.5, and 3.1.4.8 (Ref. 1). This LCO is provided to require the APRM gain or APRM Flow Biased Neutron Flux—High Function Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b) to be adjusted when operating under conditions of excessive power peaking to maintain acceptable margin to the fuel cladding integrity Safety Limit (SL) and the fuel cladding 1% plastic strain limit.

For General Electric (GE) fuel, the condition of excessive power peaking is determined by the ratio of the actual power peaking to the limiting power peaking at RTP. This ratio is equal to the ratio of the core limiting MFLPD to the Fraction of RTP (FRTP), where FRTP is the measured THERMAL POWER divided by the RTP. Excessive power peaking exists when:

$$\frac{\text{MFLPD}}{\text{FRTP}} > 1,$$

indicating that MFLPD is not decreasing proportionately to the overall power reduction, or conversely, that power peaking is increasing. For Siemens (SPC) fuel, the condition of excessive power peaking is determined by Fuel Design Limit Ratio for Centerline Melt (FDLRC), which is defined as:

$$\text{FDLRC} = \frac{(\text{LHGR})(1.2)}{(\text{TLHGR})(\text{FRTP})},$$

where LHGR is the Linear Heat Generation Rate, FRTP is the Fraction of Rated Thermal Power, and TLHGR is the Transient Linear Heat Generation Rate limit. The TLHGR limit is specified in the COLR and protects against fuel centerline melting and the fuel cladding 1% plastic strain during transient conditions throughout the life of the fuel.

(continued)

BASES

BACKGROUND (continued)

To maintain margins similar to those at RTP conditions, the excessive power peaking is compensated by a gain adjustment on the APRMs or modification of the APRM Neutron Flux—High Function Allowable Value. Either of these adjustments has effectively the same result as maintaining FDLRC and the ratio of MFLPD to FRTP less than or equal to 1.0 and thus maintains RTP margins for APLHGR, MCPR, and LHGR. Adjustments are based on the lowest APRM Neutron Flux—High Function Allowable Value or highest APRM reading resulting from the two methods (GE or Siemens).

The normally selected APRM Flow Biased Neutron Flux—High Function Allowable Value positions the scram above the upper bound of the normal power/flow operating region that has been considered in the design of the fuel rods. The Allowable Value is flow biased with a slope that approximates the upper flow control line, such that an approximately constant margin is maintained between the flow biased trip level and the upper operating boundary for core flows in excess of about 45% of rated core flow. In the range of infrequent operations below 45% of rated core flow, the margin to scram is reduced because of the nonlinear core flow versus drive flow relationship. The normally selected APRM Allowable Value is supported by the analyses presented in Reference 2 that concentrate on events initiated from rated conditions. Design experience has shown that minimum deviations occur within expected margins to operating limits (APLHGR, MCPR, and LHGR), at rated conditions for normal power distributions. However, at other than rated conditions, control rod patterns can be established that significantly reduce the margin to thermal limits. Therefore, the APRM Flow Biased Neutron Flux—High Function Allowable Value may be reduced during operation when FDLRC or the combination of THERMAL POWER and MFLPD indicates an excessive power peaking distribution.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the APRM gain or setpoint adjustments are that acceptable margins (to APLHGR, MCPR, and LHGR) be maintained to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

UFSAR safety analyses (Ref. 2) concentrate on the rated power condition for which the minimum expected margin to the operating limits (APLHGR, MCPR, and LHGR) occurs. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limit the initial margins to these operating limits at rated conditions so that specified acceptable fuel design limits are met during transients initiated from rated conditions. At initial power levels less than rated levels, the margin degradation of the APLHGR, the MCPR, or the LHGR during a transient can be greater than at the rated condition event. This greater margin degradation during the transient is primarily offset by the larger initial margin to limits at the lower than rated power levels. However, power distributions can be hypothesized that would result in reduced margins to the pre-transient operating limit. When combined with the increased severity of certain transients at other than rated conditions, the fuel design limits and MCPR SL could be approached. At substantially reduced power levels, highly peaked power distributions could be obtained that could reduce thermal margins to the minimum levels required for transient events. To prevent or mitigate such situations, either the APRM gain is adjusted upward by the higher of the core limiting value of FDLRC or the ratio of the core limiting MFLPD to the FRTP, or the APRM Flow Biased Neutron Flux—High Function Allowable Value is required to be reduced by the lesser of either the reciprocal of the core limiting FDLRC or by the ratio of FRTP to the core limiting MFLPD. Either of these adjustments effectively counters the increased severity of some events at other than rated conditions by proportionally increasing the APRM gain or proportionally lowering the APRM Flow Biased Neutron Flux—High Function Allowable Value, dependent on the increased peaking that may be encountered.

The APRM gain and setpoint satisfy Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Meeting any one of the following conditions ensures acceptable operating margins for events described above:

a. Limiting excess power peaking;

(continued)

BASES

LCO (continued)

b. Reducing the APRM Flow Biased Neutron Flux — High Function Allowable Value by multiplying the APRM Flow Biased Neutron Flux — High Function Allowable Value by the lesser of either 1/FDLRC or the ratio of FRTP and the core limiting value of MFLPD; or

c. Increasing APRM gains to cause the APRM to read greater than or equal to 100 (%) times the higher of the core limiting value of FDLRC times FRTP or the core limiting MFLPD. This condition is to account for the reduction in margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit.

For GE fuel, MFLPD is the ratio of the limiting LHGR to the LHGR limit for the specific bundle type. For Siemens fuel, FDLRC times FRTP is the ratio of the LHGR times 1.2 to TLHGR. As power is reduced, if the design power distribution is maintained, MFLPD and FDLRC are reduced in proportion to the reduction in power. However, if power peaking increases above the design value, the MFLPD and FDLRC are not reduced in proportion to the reduction in power. Under these conditions, the APRM gain is adjusted upward or the APRM Flow Biased Neutron Flux — High Function Allowable Value is reduced accordingly. When the reactor is operating with peaking less than the design value, it is not necessary to modify the APRM Flow Biased Neutron Flux — High Function Allowable Value. Adjusting APRM gain or modifying the APRM Flow Biased Neutron Flux — High Function Allowable Value is equivalent to maintaining FDLRC and the ratio of MFLPD to FRTP less than or equal to 1.0, as stated in the LCO.

For compliance with LCO 3.2.4.b (APRM Flow Biased Neutron Flux — High Function Allowable Value modification) or LCO 3.2.4.c (APRM gain adjustment), only APRMs required to be OPERABLE per LCO 3.3.1.1, Function 2.b are required to be modified or adjusted. In addition, each APRM may be allowed to have its gain adjusted or Allowable Value modified independently of other APRMs that are having their gain adjusted or Allowable Value modified.

(continued)

BASES (continued)

APPLICABILITY	The FDLRC or the ratio of MFLPD to FRTP limit, APRM gain adjustment, or APRM Flow Biased Neutron Flux — High Function Allowable Value modification are provided to ensure that the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit are not violated during design basis transients. As discussed in the Bases for LCO 3.2.1, LCO 3.2.2, and LCO 3.2.3 sufficient margin to these limits exists below 25% RTP and, therefore, these requirements are only necessary when the reactor is operating at ≥ 25% RTP.
ACTIONS	<u>A.1</u> If the APRM gain or Flow Biased Neutron Flux — High Function Allowable Value is not within limits while FDLRC or the ratio of MFLPD to FRTP exceed 1.0, the margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit may be reduced. Therefore, prompt action should be taken to restore FDLRC and the ratio of MFLPD to FRTP to within its required limit or make acceptable APRM adjustments such that the plant is operating within the assumed margin of the safety analyses. The 6 hour Completion Time is normally sufficient to restore either FDLRC and the ratio of MFLPD to FRTP to within limits or to adjust the APRM gain or modify the APRM Flow Biased Neutron Flux — High Function Allowable Value to within limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LCO not met. <u>B.1</u> If FDLRC and the ratio of MFLPD to FRTP or the APRM Flow Biased Neutron Flux — High Function Allowable Value cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER is reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1 and SR 3.2.4.2

FDLRC and the ratio of MFLPD to FRTP is required to be calculated and compared to 1.0 or APRM gain adjusted or APRM Flow Biased Neutron Flux — High Function Allowable Value modified to ensure that the reactor is operating within the assumptions of the safety analysis. These SRs are only required to determine FDLRC and the ratio of MFLPD to FRTP and, assuming either exceeds 1.0, determine the appropriate APRM gain or APRM Flow Biased Neutron Flux — High Function Allowable Value and are not intended to be a CHANNEL FUNCTIONAL TEST for the APRM gain or Flow Biased Neutron Flux — High Function circuitry. SR 3.2.4.1 and SR 3.2.4.2 have been modified by Notes, which clarify that the respective SR does not have to be met if the alternate requirement demonstrated by the other SR is satisfied. The 24 hour Frequency of SR 3.2.4.1 is chosen to coincide with the determination of other thermal limits, specifically those for the APLHGR (LCO 3.2.1), MCPR (LCO 3.2.2), and LHGR (LCO 3.2.3). The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to APLHGR, MCPR, and LHGR operating limits at low power levels.

The 12 hour Frequency of SR 3.2.4.2 is required when either FDLRC or the ratio of MFLPD to FRTP is greater than 1.0, because more rapid changes in power distribution are typically expected.

REFERENCES

1. UFSAR, Sections 3.1.2.1, 3.1.3.2, 3.1.3.4, 3.1.3.5, and 3.1.3.8.

2. UFSAR, Chapter 15.

Note: There are no changes on this page. This page is provided for continuity only.

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

------------------------------------NOTES------------------------------------

1. Separate Condition entry is allowed for each channel.

2. When Function 2.b and 2.c channels are inoperable due to APRM indication not within limits, entry into associated Conditions and Required Actions may be delayed for up to 2 hours if the APRM, is indicating a lower power value than the calculated power, and for up to 12 hours if the APRM is indicating a higher power value than calculated power.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. <u>OR</u> A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. <u>OR</u> B.2 Place one trip system in trip.	6 hours 6 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < ~~45%~~ 38.5% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	8 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	------------------NOTE------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP ~~plus any gain adjustment required by LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint" while operating at ≥ 25% RTP.~~	7 days
SR 3.3.1.1.3	Adjust the channel to conform to a calibrated flow signal.	7 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.4	-----NOTE----- Not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. ----- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.5	Perform a functional test of each RPS automatic scram contactor.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs
SR 3.3.1.1.7	-----NOTE----- Only required to be met during entry into MODE 2 from MODE 1. ----- Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.8	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.1.1.9	Calibrate the local power range monitors.	2000 effective full power hours
SR 3.3.1.1.10	Perform CHANNEL FUNCTIONAL TEST.	92 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	Calibrate the trip units.	92 days
SR 3.3.1.1.12	Perform CHANNEL CALIBRATION.	92 days
SR 3.3.1.1.13	Verify Turbine Stop Valve – Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ ~~45%~~ 38.5% RTP.	92 days
SR 3.3.1.1.14	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. 3. For Function 2.b, not required for the flow portion of the channels. --- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.15	Perform CHANNEL FUNCTIONAL TEST.	24 months

(continued)

Note: There are no changes on this page. This page is provided for continuity only.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.16	-----------------NOTES----------------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. --------------------------------------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.17	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.18	-----------------NOTES----------------- 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the the STAGGERED TEST BASIS Frequency. --------------------------------------- Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux – High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 121/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 121/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.17	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.17	NA
2. Average Power Range Monitors					
a. Neutron Flux – High, Setdown	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.17	≤ 17.1% RTP
b. Flow Biased Neutron Flux – High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.14 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	0.56 W + 67.4% ≤ ~~0.58 W + 63.4%~~ RTP and ≤ 122% RTP(b)

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) ~~0.58 W + 59.1% and ≤ 118.4%~~ RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

0.56 W + 63.2% and ≤ 118.4%

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. Fixed Neutron Flux – High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.14 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 122% RTP
d. Inop	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.17	NA
3. Reactor Vessel Steam Dome Pressure – High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.11 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 1050 psig
4. Reactor Vessel Water Level – Low	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.11 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ ~~11.8~~ 3.8 inches
5. Main Steam Isolation Valve – Closure	1	8	F	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 9.8% closed
6. Drywell Pressure – High	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 2.43 psig

(continued)

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level – High					
a. Thermal Switch	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 38.9 gallons
	5(a)	2	H	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 38.9 gallons
b. Differential Pressure Switch	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 32.3 gallons
	5(a)	2	H	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 32.3 gallons
8. Turbine Stop Valve – Closure	≥ ~~45%~~ RTP 38.5%	4	E	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.13 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 9.7% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low	≥ ~~45%~~ RTP 38.5%	2	E	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.13 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 475 psig
10. Turbine Condenser Vacuum – Low	1	2	F	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	21.6 ≥ ~~21.8~~ inches Hg vacuum
11. Reactor Mode Switch – Shutdown Position	1,2	1	G	SR 3.3.1.1.15 SR 3.3.1.1.17	NA
	5(a)	1	H	SR 3.3.1.1.15 SR 3.3.1.1.17	NA
12. Manual Scram	1,2	1	G	SR 3.3.1.1.8 SR 3.3.1.1.17	NA
	5(a)	1	H	SR 3.3.1.1.8 SR 3.3.1.1.17	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor — Inop (continued)

Four channels of Average Power Range Monitor — Inop with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the other APRM Functions are required.

3. Reactor Vessel Steam Dome Pressure — High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific ~~safety~~ analysis ~~takes direct credit~~ for ~~this~~ Function. However, the The Reactor Vessel Steam Dome Pressure — High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 2, reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux — High signal, not the Reactor Vessel Steam Dome Pressure — High or the Main Steam Isolation Valve — Closure signals), along with the safety valves, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure — High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure — High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7a, 7b. Scram Discharge Volume Water Level—High (continued)

Four channels of each type of Scram Discharge Volume Water Level—High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve—Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve—Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 11. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Stop Valve—Closure signals are initiated from position switches located on each of the four TSVs. A position switch and two independent contacts are associated with each stop valve. One of the two contacts provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve—Closure channels, each consisting of one position switch (which is common to a channel in the other RPS trip system) and a switch contact. The logic for the Turbine Stop Valve—Closure Function is such that three or more TSVs must be closed to produce a scram. This Function must be enabled at THERMAL POWER ≥ ~~45%~~ 38.5% RTP. This is

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Turbine Stop Valve – Closure (continued)

normally accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect the OPERABILITY of this Function.

The Turbine Stop Valve – Closure Allowable Value is selected to be high enough to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve – Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function even if one TSV should fail to close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ ~~45%~~ 38.5% RTP. This Function is not required when THERMAL POWER is < ~~45%~~ 38.5% RTP since the Reactor Vessel Steam Dome Pressure – High and the Average Power Range Monitor Fixed Neutron Flux – High Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 12. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure – Low signals are initiated by the electrohydraulic control (EHC) fluid pressure at each control valve. One pressure switch is associated with each control valve, and the signal from each switch is assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ ~~45%~~ 38.5% RTP.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Control Valve Fast Closure, Trip Oil Pressure — Low (continued)

This is normally accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect the OPERABILITY of this Function.

The Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Function with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis 38.5% assumptions, whenever THERMAL POWER is ≥ ~~45%~~ RTP. This Function is not required when THERMAL POWER is < ~~45%~~ RTP, 38.5% since the Reactor Vessel Steam Dome Pressure — High and the Average Power Range Monitor Fixed Neutron Flux — High Functions are adequate to maintain the necessary safety margins.

10. Turbine Condenser Vacuum—Low

The Turbine Condenser Vacuum — Low Function is provided to shut down the reactor and reduce the energy input to the main condenser to help prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. The Turbine Condenser Vacuum — Low Function is the primary scram signal for the loss of condenser vacuum event analyzed in Reference 9. For this event, the reactor scram reduces the amount of energy required to be absorbed by the main condenser and helps to ensure the MCPR SL is not exceeded by reducing the core energy prior to the fast closure of the turbine stop valves. This Function helps maintain the main condenser as a heat sink during this event.

Turbine condenser vacuum pressure signals are derived from four pressure switches that sense the pressure in the condenser. The Allowable Value was selected to reduce the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1 (continued)

approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. ~~LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of the calculated value established by SR 3.2.4.2.~~ The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.10.

An allowance is provided that requires the SR to be performed only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.12, 3.3.1.1.14, and SR 3.3.1.1.16 (continued)

complete the SR. Note 3 to SR 3.3.1.1.14 states that for Function 2.b, this SR is not required for the flow portion of these channels. This allowance is consistent with the plant specific setpoint methodology. This portion of the Function 2.b channels must be calibrated in accordance with SR 3.3.1.1.16.

The Frequency of SR 3.3.1.1.12 is based upon the assumption of a 92 day calibration interval in determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.14 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.16 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.13

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently 38.5% bypassed when THERMAL POWER is ≥ ~~45%~~ RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during an in-service 38.5% calibration at THERMAL POWER ≥ ~~45%~~ RTP, if performing the calibration using actual turbine first stage pressure, to ensure that the calibration remains valid.

38.5%

If any bypass channels setpoint is nonconservative (i.e., the Functions are bypassed at ≥ ~~45%~~ RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

(continued)

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater System and Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The Feedwater System and Main Turbine High Water Level Trip Instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level reference point, causing the trip of the three feedwater pumps and the main turbine.

Reactor Vessel Water Level — High signals are provided by differential pressure indicating switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level in the reactor vessel (variable leg). Two channels of Reactor Vessel Water Level — High instrumentation are provided as input to a two-out-of-two initiation logic that trips the three feedwater pumps and the main turbine. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a feedwater pump and main turbine trip signal to the trip logic.

A trip of the feedwater pumps limits further increase in reactor vessel water level by limiting further addition of feedwater to the reactor vessel. A trip of the main turbine and closure of the stop valves protects the turbine from damage due to water entering the turbine.

APPLICABLE SAFETY ANALYSES

The Feedwater System and Main Turbine High Water Level Trip Instrumentation is assumed to be capable of providing a feedwater pump and main turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The high level trip indirectly initiates a reactor scram from the main turbine trip (above ~~45%~~ 38.5% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

(continued)

BASES

LCO (continued)

calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

APPLICABILITY

The Feedwater System and Main Turbine High Water Level Trip Instrumentation is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE," ~~and LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint,"~~ sufficient margin to these limits exists below 25% RTP; therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

With one or more channels inoperable, the Feedwater System and Main Turbine High Water Level Trip Instrumentation cannot perform its design function (Feedwater System and main turbine high water level trip capability is not maintained). Therefore, continued operation is only permitted for a 2 hour period, during which Feedwater System and main turbine high water level trip capability must be restored. The trip capability is considered maintained when sufficient channels are OPERABLE or in trip such that the Feedwater System and main turbine high water level trip logic will generate a trip signal on a valid signal. This requires two channels to each be OPERABLE or in trip. If the required channels cannot be restored to OPERABLE status or placed in trip, Condition B must be entered and its Required Action taken.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of Feedwater System and Main Turbine High Water Level Trip Instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

(continued)

Note: There are no changes on this page. This page is provided for continuity only.

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 1.a, 2.a, 2.b, 3.d, 5.b and 6.b <u>AND</u> 24 hours for Functions other than Functions 1.a, 2.a, 2.b, 3.d, 5.b and 6.b
B. One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour

(continued)

Table 3.3.6.1-1 (page 1 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ -55.2 inches
b. Main Steam Line Pressure – Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≥ 831 psig
c. Main Steam Line Pressure – Timer	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 0.331 seconds
d. Main Steam Line Flow – High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.6 SR 3.3.6.1.7	254.3 psid ≤ ~~138% rated steam flow~~
e. Main Steam Line Tunnel Temperature – High	1,2,3	2 per trip string	D	SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 198°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	3.8 ≥ ~~11.8~~ inches
b. Drywell Pressure – High	1,2,3	2	G	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≤ 2.43 psig
c. Drywell Radiation – High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 70 R/hr

(continued)

Table 3.3.6.1-1 (page 3 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Reactor Water Cleanup System Isolation					
a. SLC System Initiation	1,2	1	H	SR 3.3.6.1.7	NA
b. Reactor Vessel Water Level – Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ ~~11.8~~ 3.8 inches
6. RHR Shutdown Cooling System Isolation					
a. Reactor Vessel Pressure – High	1,2,3	2	F	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≤ 130 psig
b. Reactor Vessel Water Level – Low	3,4,5	2(b)	I	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ ~~11.8~~ 3.8 inches

(b) In MODES 4 and 5, provided RHR Shutdown Cooling System integrity is maintained, only one channel per trip system with an isolation signal available to one shutdown cooling pump suction isolation valve is required.

Note: There are no changes on this page. This page is provided for continuity only.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety and Relief Valves

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety valves are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB). Each unit is designed with nine safety valves, one of these valves also functions in the relief mode. This valve is a dual function Target Rock safety/relief valve (S/RV).

The safety valves and S/RV are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The safety valves actuate in the safety mode (or spring mode of operation). In this mode, the safety valve opens when the inlet steam pressure reaches the lift set pressure. At that point, the vertical upward force generated by the inlet pressure under the valve disc balances the downward force generated by the spring. Slight steam leakage develops across the valve disc-to-seat interface and is directed into the huddle chamber. Pressure builds up rapidly in the huddle chamber developing an additional vertical lifting force on the disc and disc holder. This additional force in conjunction with the expansive characteristic of steam causes the valve to "pop" open to almost full lift. This satisfies the Code requirement. The S/RV is a dual function Target Rock valve that can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the S/RV opens in the same manner as described above for the safety valves. In the relief mode (or power actuated mode of operation), automatic or manual switch actuation energizes a solenoid valve which pneumatically actuates a plunger located within the main valve body. Actuation of the plunger allows pressure to be vented from the top of the main valve piston. This allows reactor pressure to lift the main valve piston, which opens the main valve. The relief valves and S/RV discharge steam through a discharge line to a point below the minimum water level in the suppression pool. All other safety valves discharge directly to the drywell.

(continued)

BASES

BACKGROUND (continued)

In addition to the safety valves and S/RV, each unit is designed with four relief valves which actuate in the relief mode to control RCS pressure during transient conditions to prevent the need for safety valve actuation (except S/RV) following such transients. The relief valves are also located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. ~~These valves are sized by assuming a turbine trip, a coincident scram and a failure of the turbine bypass system.~~ For Unit 1, four of the relief valves are of the Electromatic type, which are opened by automatic or manual switch actuation of a solenoid. The switch energizes the solenoid to actuate a plunger, which contacts the pilot valve operating lever, thereby opening the pilot valve. When the pilot valve opens, pressure under the main valve disc is vented. This allows reactor pressure to overcome main valve spring pressure, which forces the main valve disc downward to open the main valve. For Unit 2, four of the relief valves are of the Target Rock power operated relief valve type. When the solenoid is energized, a magnetic force is developed which moves a plunger upward until it contacts the moveable core. This motion is transmitted through the pilot rod to fully open two pilot discs, allowing the control pressure above the main disc to vent through the second pilot seat to the downstream side of the valve. In addition, the motion of the pilot disc partially reduces the control pressure above the main disc. When the force of the control pressure acting on the top of the main disc falls below the force of the inlet pressure acting on the lower annular area, the main disc will move to the open position. In the open position, with the moveable core positioned close to the fixed core, the magnetic force is well in excess of the closing forces due to control pressure and return spring force. This ensures that the main disc will be held firmly in the open position. The main disc can be opened even with the valve inlet pressure equal to 0 psig. Two of the five relief valves are the low set relief valves and all of the relief valves, including the S/RV, are Automatic Depressurization System (ADS) valves. The low set relief requirements are specified in LCO 3.6.1.6, "Low Set Relief Valves," and the ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND

The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of design basis accidents and transients.

APPLICABLE SAFETY ANALYSES

The reactor steam dome pressure of ≤ 1005 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analyses are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analyses of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO ~~3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint"~~). The nominal reactor operating pressure is approximately 1005 psig. Transient analyses typically use the nominal or a design dome pressure as input to the analysis. Small deviations (5 to 10 psi) from the nominal pressure are not expected to change most of the transient analyses results. However, sensitivity studies for fast pressurization events (main turbine generator load rejection without bypass, turbine trip without bypass, and feedwater controller failure) indicate that the delta-CPR may increase for lower initial pressures. Therefore, the fast pressurization events have considered a bounding initial pressure based on a typical operating range to assure a conservative delta-CPR and operating limit.

Reactor steam dome pressure satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from relief valve discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from steam exhaust lines in the turbine driven systems (i.e., the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation;

b. Primary containment peak pressure and temperature;

c. Condensation oscillation loads; and

d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses (Reference 1) include initial suppression pool water volume and suppression pool temperature ~~(Reference 1 for LOCAs and Reference 2 for the pool temperature analyses required by Reference 3).~~ An initial pool temperature of 95°F is assumed for the Reference 1~~, 2, and 4~~ analyses. Reactor shutdown at a pool temperature of

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. UFSAR, Section 6.2.

2. ~~UFSAR, Chapter 6.2.1.3.4.5.~~

3. ~~NUREG-0783.~~

4. ~~Quad Cities Nuclear Power Station Units 1 and 2, Mark 1 Plant Unique Analysis Report, COM-02-039-1, May 1983.~~

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Condenser Offgas

BASES

BACKGROUND

During unit operation, steam from the low pressure turbine is exhausted directly into the main condenser. Air and noncondensible gases are collected in the main condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases.

The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the holdup line.

APPLICABLE SAFETY ANALYSES

The main condenser offgas gross gamma activity rate is an initial condition of the Main Condenser Offgas System failure event, discussed in Reference 1. The analysis assumes a gross failure in the Main Condenser Offgas System that results in the rupture of the Main Condenser Offgas System pressure boundary. The gross gamma activity rate is controlled to ensure that, during the event, the calculated offsite doses will be well within the limits of 10 CFR 100 (Ref. 2).

The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

To ensure compliance with the assumptions of the Main Condenser Offgas System failure event (Ref. 1), the fission product release rate should be consistent with a noble gas release to the reactor coolant of 100 μCi/MWt-second after decay of 30 minutes. The LCO is ~~established consistent with this requirement~~ conservatively based on a reactor power level of 2511 MWt. (2511 MWt x 100 μCi/MWt-second = 251,100 μCi/second).

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.7 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass
33% capacity of the system is 40% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of a nine valve manifold connected to the main steam lines between the main steam isolation valves and the main turbine stop valves. Each of the nine valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro-Hydraulic Control System, as discussed in the UFSAR, Section 7.7.4 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves sequentially. When the bypass valves open, the steam flows from the main steam equalizing header to the bypass manifold through the bypass valve, to its bypass line, where an orifice further reduces the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the turbine trip, turbine generator load rejection and feedwater controller failure transients, as discussed in the UFSAR, Sections 15.2.3.2, 15.2.2.2, and 15.1.2 (Refs. 2, 3, and 4, respectively). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in an MCPR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

3. A required system redundant to support system(s) for the supported systems described in b.1 and b.2 above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.12 Primary Containment Leakage Rate Testing Program

a. This program shall establish the leakage testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemption. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Testing Program," dated September 1995.

b. The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 48 psig.
43.9

c. The maximum allowable primary containment leakage rate, L_a, at P_a, is 1% of primary containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Primary containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and Type C tests, and $\leq 0.75\ L_a$ for Type A tests.

2. Air lock testing acceptance criteria is the overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

e. The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

Note: There are no changes on this page. This page is provided for continuity only.

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

(ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

5.6.3 Radioactive Effluent Release Report

------------------------------NOTE------------------------------

A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and the Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the safety and relief valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

   1. The APLHGR for Specification 3.2.1.

   2. The MCPR for Specification 3.2.2.

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

3. The LHGR for Specification 3.2.3.

4. The LHGR and ~~transient~~ linear heat generation ~~rate limit~~ ~~for Spec~~ification 3.2.4.

4. Control Rod Block Instrumentation Setpoint for the Rod Block Monitor—Upscale Function Allowable Value for Specification 3.3.2.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel."

2. Commonwealth Edison Topical Report NFSR-0085, "Benchmark of BWR Nuclear Design Methods."

3. Advanced Nuclear Fuels Methodology for Boiling Water Reactors, XN-NF-80-19(P)(A).

4. Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel, XN-NF-85-67(P)(A).

5. Qualification of Exxon Nuclear Fuel for Extended Burnup, XN-NF-82-06(P)(A).

6. Advanced Nuclear Fuels Corporation Generic Mechanical Design for Advanced Nuclear Fuels 9x9-IX and 9x9-9X BWR Reload Fuel, ANF-89-014(P)(A).

7. Generic Mechanical Design Criteria for BWR Fuel Designs, ANF-89-98(P)(A).

8. Exxon Nuclear Plant Transient Methodology for Boiling Water Reactors, XN-NF-79-71(P)(A).

9. ANFB Critical Power Correlation, ANF-1125(P)(A).

(continued)

ATTACHMENT C

Proposed Changes to Operating Licenses and Technical Specifications for Quad Cities Nuclear Power Station, Units 1 and 2

INFORMATION SUPPORTING A FINDING OF NO SIGNIFICANT HAZARDS CONSIDERATION

According to 10 CFR 50.92(c), "Issuance of Amendment," a proposed amendment to an operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not:

Involve a significant increase in the probability or consequences of an accident previously evaluated; or

Create the possibility of a new or different kind of accident from any accident previously evaluated; or

Involve a significant reduction in a margin of safety.

In support of this determination, an evaluation of each of the three criteria set forth in 10 CFR 50.92 is provided below regarding the proposed license amendment.

Overview

Commonwealth Edison (ComEd) Company is requesting changes to Facility Operating License Nos. DPR-29 and DPR-30, and Appendix A, Technical Specifications (TS), for Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2. The proposed changes will revise the maximum power level specified in each unit's license, and TS definition of rated thermal power. In addition, other TS changes associated with this power uprate request are proposed. The specific changes requested are as follows.

- The maximum power level specified in each unit's license will be increased.
- The allowance to specify containment overpressure to assure adequate Net Positive Suction Head (NPSH) for the Emergency Core Cooling System (ECCS) pumps during a design basis accident (DBA) will be revised.
- The value of Rated Thermal Power (RTP) in the definitions will be increased.
- The definition of the Fuel Design Limiting Ratio for Centerline Melt (FDLRC) will be deleted.
- The definition of the Maximum Fraction of Limiting Power Density (MFLPD) will be deleted.
- The specification for the Average Power Range Monitor (APRM) gain and setpoint adjustment will be deleted as a result of the implementation of the APRM/Rod Block Monitor (RBM) TS (ARTS) power and flow dependent limits.
- Reactor Protection System (RPS) instrumentation changes will be implemented.
- Primary Containment Isolation instrumentation changes will be implemented.
- The peak calculated containment internal pressure P_a, for the design basis loss of coolant accident (LOCA) will be updated.
- The requirement to include the Transient Linear Heat Generation Rate (TLHGR) in the Core Operating Limits Report (COLR) will be deleted as a result of the implementation of the ARTS power and flow dependent limits.

The QCNPS has completed comprehensive extended power uprate (EPU) analyses to increase the licensed reactor power level from 2511 Megawatts-thermal (MWt) to

2957 MWt for both Units 1 and 2. The EPU program included a reanalysis or evaluation of DBAs, non-LOCA accidents, Nuclear Steam Supply System (NSSS) and balance of plant (BOP) structures, systems and components. Major NSSS and BOP components and systems have been assessed with respect to the bounding conditions expected for operation at the uprated power level. The results of the analyses and evaluations have yielded acceptable results and demonstrated that all design basis acceptance criteria will continue to be met during uprated power operations. The detailed analysis is presented in General Electric (GE) Report NEDC-21961P, "Safety Analysis Report for Quad Cities 1 & 2 Extended Power Uprate," dated December 2000.

The analyses and evaluations supporting the proposed changes directly related to power uprate were completed using the guidelines in GE Topical Report NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate." Certain issues are evaluated generically and have been submitted to the NRC in GE Topical Report NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate." The NRC has approved both of these topical reports in letters to G.L. Sozzi (GE), "Staff Position Concerning General Electric Boiling-Water Reactor Extended Power Uprate Program," dated February 8, 1996,and J.F. Quirk (GE), "Staff Safety Evaluation of General Electric Boiling Water Reactor (BWR) Extended Power Uprate Generic Analyses," dated September 14, 1998.

Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

As summarized below, the increase in power level with Average Power Range Monitor (APRM) / Rod Block Monitor (RBM) Technical Specifications (ARTS) power and flow dependent limits improvements and the related Technical Specification (TS) changes discussed herein will not significantly increase the probability or consequences of an accident previously evaluated.

The probability of design basis accidents (DBAs) occurring is not affected by the increased power level or by the ARTS power and flow dependent limits, because plant equipment still complies with the applicable regulatory and design basis criteria. An evaluation of the Boiling Water Reactor (BWR) probabilistic risk assessments concludes that the calculated core damage frequencies do not significantly change due to extended power uprate (EPU) or ARTS power and flow dependent limits. Scram setpoints are established such that there is no significant increase in scram frequency due to uprate. No new challenges to safety-related equipment result from EPU or ARTS power and flow dependent limits.

Radiological release events have been evaluated, and shown to meet the requirements of 10 CFR 100, "Reactor Site Criteria." Therefore, the changes in consequences of hypothetical accidents are insignificant. The EPU accident evaluation results do not exceed any of the NRC approved acceptance limits. The spectrum of hypothetical accidents and transients has been investigated, and are shown to meet the plant's currently licensed regulatory criteria. In the area of core design, for example, the fuel operating limits such as Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) and Safety Limit Minimum Critical Power Ratio (SLMCPR) are still met, and fuel reload analyses will show that plant transients meet the criteria accepted by the

NRC as specified in GE Topic Report NEDO-24011, "GESTAR II." Challenges to fuel are evaluated, and shown to still meet the criteria of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Power Reactors" and Appendix K, "ECCS Evaluations Models."

Challenges to the containment have been evaluated, and the containment and its associated cooling systems continue to meet 10 CFR 50 Appendix A, "General Design Criteria for Nuclear Power Plants," Criterion 38, "Long Term Cooling," and Criterion 50, "Containment."

The implementation of ARTS power and flow dependent limits does not affect the radiological analysis result from any postulated accident, nor does it affect the containment analysis.

The additional TS changes directly support the increased power level. All of these changes are either administrative or are proposed to ensure that the plant response to accidents and transients remain within acceptance criteria.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

Does the proposed change create the possibility of a new of different kind of accident from any accident previously evaluated?

As summarized below, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

Equipment that could be affected by EPU or ARTS power and flow dependent limits has been evaluated. No new operating mode, safety-related equipment lineup, accident scenario or equipment failure mode is involved with EPU. The full spectrum of accident considerations, defined in Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants LWR Edition," has been evaluated, and no new or different kind of accident has been identified. EPU and ARTS power and flow dependent limits uses already developed technology, and applies it within the capabilities of already existing plant equipment in accordance with presently existing regulatory criteria. Industry experience with ARTS and BWRs with higher power levels than described herein have not identified any new power dependent or ARTS related accident.

Therefore, the proposed changes to not crease the possibility of a new or different kind of accident from any accident previously evaluated.

Does the proposed change involve a significant reduction in a margin of safety?

As summarized below, this change will not involve a significant reduction in a margin of safety.

EPU affects only design and operational margins. Challenges to the fuel, reactor coolant pressure boundary, and containment were reanalyzed for EPU conditions. The fuel integrity is maintained by meeting existing design and regulatory limits. The calculated loads of all affected structures, systems and components, including the reactor coolant pressure boundary, remain within design allowables for all DBA categories. The containment performance analysis demonstrates that the containment remains within all of its design limits following the most severe DBA.

The use of ARTS power and flow dependent limits improvements ensures that the plant does not exceed any fuel thermal limit, and thus, the margin of safety is not affected.

Because the plant reactions to transients and accidents do not result in exceeding the presently approved NRC acceptance limits, EPU with ARTS power and flow dependent limits does not involve a significant reduction in a margin of safety.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Conclusion

An EPU to 117.8% of original rated power with ARTS power and flow dependent limits has been investigated. The method for achieving higher power is to slightly increase some plant operating parameters. The plant licensing challenges have been evaluated and demonstrate how this uprate with ARTS power and flow dependent limits can be accommodated without a significant increase in the probability or consequences of an accident previously evaluated, without creating the possibility of a new or different kind of accident from any accident previously evaluated, and without exceeding any presently existing regulatory limits or acceptance criteria applicable to the plant which might cause a reduction in a margin of safety.

Having arrived at negative declarations with regards to the criteria of 10 CFR 50.92, this assessment concludes that power uprate of the amount described herein and ARTS power and flow dependent limits do not involve a Significant Hazards Consideration.

ATTACHMENT D

Proposed Changes to Operating Licenses and Technical Specifications for Quad Cities Nuclear Power Station, Units 1 and 2

INFORMATION SUPPORTING AN ENVIRONMENTAL ASSESSMENT

In accordance with 10 CFR 51.21, "Criteria for and identification of licensing and regulatory actions requiring environmental assessments," Commonwealth Edison (ComEd) has prepared a supplement to the Quad Cities Nuclear Power Station (QCNPS) environmental report to describe the environmental effects of the Extended Power Uprate (EPU) project. This report is attached.

ComEd has evaluated this proposed change against the criteria for identification of licensing and regulatory actions requiring environmental impact statements and has determined that these proposed changes do meet the requirements for an environmental impact statement set forth in 10 CFR 51.20, "Criteria for and identification of licensing and regulatory actions requiring environmental impact staements." As demonstrated in the attached report, there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite and there is no significant increase in individual or cumulative occupational radiation exposure.