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DAEC Plant Support Center
Operated by Nuclear Management Company, LLC

May 11, 2001
NG-01-0655

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station 0-P1-17
Washington, DC 20555-0001

Subject:	Duane Arnold Energy Center Docket No: 50-331 Op. License No: DPR-49 Response to Request for Additional Information (RAI) to Technical Specification Change Request TSCR-042 – Extended Power Uprate. (TAC # MB0543)
Reference:	NG-00-1900, "Technical Specification Change Request (TSCR-042): 'Extended Power Uprate'," dated November 16, 2000.
File:	A-117, SPF-189

Dear Sir(s):

On May 1, 2001, a conference call was held with the NRC Staff regarding the referenced amendment request to increase the authorized license power level of the Duane Arnold Energy Center. In order to complete their review, the Staff has requested additional information to our application. The proposed Request for Additional Information (RAI) had been provided to us electronically on April 23, 2001 to facilitate discussions. As a result of this conference call, some modifications were made to this draft RAI. Subsequent to this call, additional questions were transmitted to us electronically. Consequently, the Attachment to this letter contains all the RAI and our Responses.

No new commitments are being made in this letter.

Please contact this office should you require additional information regarding this matter.

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This letter is true and accurate to the best of my knowledge and belief.

NUCLEAR MANAGEMENT COMPANY, LLC

By Gary Van Middlesworth
Gary Van Middlesworth
DAEC Site Vice-President

State of Iowa
(County) of Linn

Signed and sworn to before me on this 11th day of May, 2001,
by Gary Van Middlesworth.

Kathleen M. Jarman
Notary Public in and for the State of Iowa

Nov. 3, 2001
Commission Expires

Attachment: 1) DAEC Responses to NRC Electrical Systems Branch Request for Additional Information Regarding Proposed Amendment for Power Uprate

cc: T. Browning
R. Anderson (NMC) (w/o Attachment)
B. Mozafari/Darl Hood (NRC-NRR)
J. Dyer (Region III)
D. McGhee (State of Iowa)
NRC Resident Office
Docu

DAEC Responses to NRC
Electrical Systems Branch
Request for Additional Information
Regarding Proposed Amendment for Power Uprate

1. In Section 6.6, the licensee has stated that the heat load discussed above represent an increase of approximately 2% to 5% in the drywell cooling, reactor building, and main steam tunnel and approximately 21% in the heater bay area total heat loads. Will this increase heat load impact power requirements for Drywell cooling units (100HP/88KW) and reactor building cooling water system pump (40HP/35 KW) and as a result impact emergency diesel generator loading? Also, provide a discussion regarding the impact on equipment qualification of equipment subject to this increased heat load.

DAEC Response:

The slight increase in Drywell heat load discussed is during normal operation and not under accident conditions. The Technical Specification requirement to maintain normal drywell temperature ≤ 135°F is not being changed by power uprate. Thus, under design basis accident conditions, the Drywell Cooling System load on the emergency diesel generators will not change due to the increase in heat load during normal operation.

As discussed in Section 6.4.3, the Reactor Building Closed Cooling Water system will experience an increase in various heat loads on the system due to power uprate, but they are within the system's heat removal capacity. These pumps are automatically load shed from essential busses under accident conditions.

Thus, as stated in Section 6.1.2, the loading on the emergency diesel generators is not impacted by the power uprate.

Environmental qualifications issues are addressed in Question 6 below.

2. In Section 6.1.1, the licensee stated that this analysis will be re-performed when the main transformers are replaced to confirm that there is no affect on grid stability or reliability at 1912 MWt. How can the staff approve extended power uprate of 1912 MWt without the analysis verifying that there is no effect on grid stability or reliability? Provide grid stability and reliability analysis including major assumptions, primary findings, and conclusions.

Per the conference call on May 01, 2001, the above question was modified to provide a summary of the current evaluation mentioned in the submittal and a description of the process for updating it for extended power uprate.

DAEC Response:

Justification for Approval of Power Uprate

Review of the grid reliability and stability aspects of a power uprate are performed to ensure compliance with General Design Criteria (GDC) 17. Specifically, GDC 17 requires that "provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

The issue of grid stability is not limited to power uprate, nor is it only influenced by changes made internally by a nuclear power plant. It is the dynamic nature of the grid that limits the time that any grid stability study remains valid. New plants are constructed, new load is added, the distribution system is modified, and even the limiting grid fault can change over time, all of which have a direct impact on the grid stability analysis. Proposed additions that would affect our current grid stability analysis include a 345 KV transmission line from the Arrowhead substation in Minnesota to the Weston substation in Wisconsin, potential installation of gas turbine generation capacity within the Alliant Energy territory, and an additional 2000 MWe of new generation in the Alliant territories in Iowa and Wisconsin in the near future.

Electrical distribution system reliability is important for nuclear plant safety because loss of offsite power is a leading initiator for core damage in the DAEC probabilistic risk assessment. It is also important to the health and safety of the public because of society's dependence on reliable electric power. The purpose of evaluating grid stability for DAEC has two goals: first, we ensure that changes we make to the facility do not adversely affect grid stability; and, second, we want to be aware of any externally-generated changes to the grid that could increase the risk of a transient that could impact the DAEC.

DAEC UFSAR Section 8.2.2.1 states "Stability analyses of the interconnected power grid due to the loss of the DAEC generating capacity was submitted with the PSAR and updated stability analysis are performed by MAIN affiliates whenever significant grid changes are made." As stated in PUSAR Section 6.1.1, the current grid stabililty analysis was performed assuming the reactor power of the DAEC was increased to 1790 MWt, with a corresponding increase in generator output of 641 MWe (gross). The current output capability is limited based on the currently-installed Main Transformer rating of 660 MVA and Isolated Phase Bus of 18,000 amperes.The UFSAR commits us to performing a new stability study for the Main Transformer replacement, which is required to increase power above the 1790 MWt (641 MWe) level and for any significant increase in actual plant electrical output up to operation at the power uprate level of 1912 MWth.

We believe that an analysis performed today, projecting the conditions at the time the DAEC achieves the power uprate of 1912 MWt, would not be meaningful in demonstrating that grid stability will remain acceptable. We have performed a new analysis in support of the power uprate that reflects current, or near-term, grid and plant configurations. We plan to update the existing grid stability study as additional changes occur, as required by our licensing basis in UFSAR Section 8.2.2.1. By more accurately reflecting current grid and plant configuration, and through periodic updates, this approach provides greater confidence that future changes that impact grid stability will not adversely affect the safety of the DAEC and will also ensure that the reliability of our power production is maintained, consistent with GDC 17. Therefore, the DAEC believes that the staff should approve the power uprate to 1912 MWt based upon current and continued conformance to GDC 17.

Grid Stability and Reliability Analysis

Assumptions, Methods, and Inputs

The Alliant Energy System Planning Department used Power Technologies Inc.'s PSS/E software package to perform the grid stability study. The package is used by the regional reliability council for performing systems studies. The model used was the MAPP model for the summer of the year 2001. The MAPP model for the summer of the year 2001 contains assumptions as to the load growth, installed/operating generation and installed/operating transmission system components (transmission lines, transformers, capacitor banks, etc.). These assumptions have been reviewed and approved by the appropriate MAPP committees. MAPP Design Review Subcommittee accepted the study as part of the support for the planned accreditation of the power uprate.

The reliability study included the effects of trips of the DAEC with contingencies for 68 transmission line outages and 16 transformer outages as required by MAPP/MAIN for Iowa grid reliability and stability studies. All voltages at the DAEC were within the acceptance limits of 95% to 105% voltage.

For grid reliability effects of a DAEC outage, the study included worst case power to flow on the grid with the DAEC in service, and the effects of single line to ground faults with circuit failure near DAEC. For stability analysis the trips of the Prairie Island – Byron 345 KV line and the King – Eau Claire 345 KV line were modeled.

As discussed above, PUSAR Section 6.1.1 states that a grid stability study was performed for a plant power of 1790 MWt (641 MWe gross). This study reflects a plant output limitation based on the currently installed main transformer rating of 660 MVA and current Isolated Phase Bus of 18,000 amperes.

The DAEC is currently accredited for 520 MWe net (summer peak) and 535 MWe net (winter peak). The grid stability analysis assumed DAEC accreditation for 585 MWe net (summer peak) and 600 MWe (winter peak). For the worst case fault response analysis additional margin was added by assuming DAEC power output at 610 MWe net (641 MWe gross) further reducing the assumed MVAR capacity of DAEC.

The study assumed that the King – Eau Claire – Arpin transmission line was initially loaded to greater than 800 MWe for 3 of the 5 case studies. For the remaining two cases, the line was loaded to the stability limit for each case, i.e., 715 MWe. Current MAPP/MAIN operating procedures limit the loading of this transmission line to 750 MWe for off-peak periods and 700 MWe during peak periods, for grid reliability reasons unrelated to the DAEC. Proposed additional generation from Lakefield LLP Martin County generating station and MEC's Cordova Station were included with loads synchronized to the south and east of MAAP to create a worst case scenario. Iowa wind generation was included at average output. System transfers to published limits on the Manitoba Hydro Export and North Dakota Export interfaces were included to provide system stress.

Initial stability studies considered the MAAP 1999 Series, 2001 Summer Peak and 2000 Summer peak cases. Loads were scaled to create a 2001 off-peak case. Adjustments were made to the model of Commonwealth Edison control area to prevent unrealistic damping. The 2001 Summer Peak case was determined to be the limiting case.

Evaluations of stability included Rotor Angle Stability, Small Signal Stability (Damping) and VAR Capability

Results, Findings, and Conclusions

Iowa has traditionally been regarded as a transiently stable region to all known operating conditions. The increase in DAEC generator output does not cause any detriment to the rotor angle stability of Iowa of the MAPP/MAIN transmission system.

Since grid voltages and power flows resulting from a DAEC plant trip remain within acceptance limits, there is no impact to the reliability of offsite power to the DAEC as a result of a DAEC trip.

The analysis found that the worst case events for rotor angle stability were trips of the Quad Cities 345 KV, and a trip of a DAEC 161 KV line. All faults were within the capability of existing mitigation schemes and equipment. The grid remained stable with no MAPP acceptance criteria violations. Rotor oscillation damping remained unchanged for all generators including DAEC. Differences between rotor angle swing at current DAEC accredited power and the interim power operation at 1790 MWt were very slight, with no degradation of stability.

Prony analysis was performed for a trip of the Prairie Island – Byron 345 KV line to analyze the effect of the DAEC uprate on the 0.25 Hz mode oscillation of the MAPP region. There was a slight increase in the damping of the MAPP 0.25% mode of oscillation at 70% load levels, but no instability or system degradation was found.

The VAR stability study and operating experience confirm that the bounding grid event for the DAEC VAR loading is a trip of the King - Eau Claire - Arpin 345 KV transmission line in Wisconsin with heavy transfer of power from Minnesota to Wisconsin. With the King - Eau Claire - Arpin transmission line loaded at 825 MWe, a trip of the line would require approximately 340 MVAR from the DAEC and/or Cedar Rapids area. This 340 MVAR would be required to maintain voltage levels in Eastern Iowa in the acceptable range.

Without modifications to increase DAEC generator capability, the reactive power capability of the generator decreases as real power level increased due to operating further out on the generator capability curve. At 1790 MWth, the Main Generator would be capable of approximately 280 MVARs and at 1912 MWth, the Main Generator would be capable of approximately 240 MVARs.

As long as the reactive power requirement for a trip of the King - Eau Claire - Arpin line is maintained, voltages at the DAEC will remain above the minimum required (95% voltage at the 161 KV bus) for all contingencies modeled. To compensate for DAEC MVAR capacity reduction at 1790 MWt and for other grid reliability reasons unrelated to the DAEC power uprate, capacitor banks are being installed in the Cedar Rapids area. Additional VAR compensation may be needed to achieve full uprated power of 1912 MWt.

Based on the results of the above analysis, the power uprate of the DAEC will not violate the MAPP acceptance criteria. Therefore, DAEC's conformance to GDC-17 will not be compromised.

3. In Section 6.1.2, the licensee stated that due to the increased motor demand, the existing design basis calculations will be re-performed to reflect the changes in motor demand, and to confirm that the increased electrical distribution loading due to extended power uprate (EPU) does not affect the system capacity to provide adequate electrical power and provide this power within equipment ratings. How will the licensee assure that the electrical distribution system is adequate without the reanalysis?

DAEC Response:

As discussed in Section 6.1.2, the only known impacts on the on-site AC distribution system are the reactor recirculation, condensate and feedwater pump loads. These are all non-safety-related equipment, powered by the station non-essential busses. The essential AC busses are not impacted by power uprate, as stated in Section 6.1.2.

Justification for future modifications

The DAEC Power System Analysis program is a formal part of the DAEC design control process via the Power System Analysis Checklist. This checklist is required to be completed for every DAEC modification which affects plant electrical loading, both essential and non-essential distribution systems. A preliminary analysis is performed at the initial design stage. If the preliminary analysis indicates that there is a possibility that the modification will impact the results of the Power Systems Analysis, a more-detailed analysis is performed to fully evaluate the affect of the modification and to allow any necessary changes to the modification before it is implemented.

The above load changes due to power uprate have had a scoping study performed for preliminary rating, voltage drop and short circuit analysis. Due to the large amount of conservatism built into the current Power Systems Analysis, it is expected that the additional power uprate electrical loading changes will have little or no impact on the analysis conclusions. The final design and analysis for these modifications will be performed, using the above-described design control process, and implemented pursuant to the requirements of 10 CFR 50.59.

4. In Section 6.1.2, the licensee stated that protective relaying equipment modifications are necessary to accommodate the increased motor demands for the condensate pumps and reactor feed pumps. How will the licensee verify that motors are protected and coordination is maintained without reanalysis of protection and coordination of equipment?

DAEC Response:

As described in our Response to Question 3 above, the DAEC's design control process will ensure that the proper evaluations are performed as part of the final design of these modifications.

5. In Section 6.1.2, the licensee stated that operation at the EPU rated thermal power level is achieved by utilizing new or existing equipment operating within its design capability. Provide details (rating, impact on voltage drop, short circuit calculations, and other calculations as applicable) about the new equipment if used.

DAEC Response:

As described in our Response to Question 3 above, the final design of these balance-of-plant modifications is not yet complete. The DAEC's design control process will ensure that the proper evaluations are performed as part of the final design of these modifications.

6. In section 10.3.1.1, the licensee stated that the equipment inside the containment will be requalified or upgraded to new temperature profiles as part of the implementation of the EPU. Identify the subject equipment and discuss how this equipment will be requalified for the new temperature profiles. (The staff would like to have a meeting with the licensee regarding the new temperature profiles and equipment test profiles).

   Per the conference call on May 01, 2001, the above question was modified to provide the drywell temperature profile and an example evaluation summary for one component, along with an explanation of how the requalification was being performed.

DAEC Response:

As shown in Figure 1 (attached), the power uprate drywell temperature for the limiting steamline break (SLB) exceeds the existing environmental qualification (EQ) profile at about 1 hour, but the current profile remains bounding for the maximum, peak value.

The following is the summary evaluation for one example component:

For the Drywell electrical penetration assemblies, the as-tested accident profile included 10 days at 281 °F (the Drywell design temperature), which was used to demonstrate an equivalent post-accident period of 56 days at a temperature of 200 °F for the current DAEC conditions. However, for the DAEC power uprate, a new post-accident profile of 12 days at 205 °F, and 140 °F for 18 days thereafter, has been established. To demonstrate that the as-tested accident profile still envelops the DAEC power uprate profile, the Arrhenius methodology is conservatively applied to demonstrate an equivalent of 50 days at 205 °F as follows:

$$t_{EQV} = t_{SVC} / e^{\varnothing/K}[1/T_{SVC} - 1/T_{EQV}]$$

where:

t_{EQV} = time at equivalent aging temperature (T_{EQV})
T_{EQV} = 205 °F (96.11 °C or 369.27 °K)

t_{SVC} = time at service temperature (T_{SVC})
T_{SVC} = 281 °F (138.33 °C or 411.49 °K)
$\varnothing$ = 0.5 eV

In addition to the changes resulting from the new accident temperature profile, a minor change has occurred in the normal operating temperature in the Drywell. With power uprate, the ambient temperature increases 1.3 °F. This does not impact the qualified life of the equipment in the Drywell because this minor increase is within the tolerance applied to temperatures used in the determination of qualified life for this location. Qualified life determinations for equipment in the Drywell utilize actual in-plant operating data obtained from either locally-mounted devices or area-monitoring temperature elements used for routine temperature monitoring; so, if any temperature changes occur, they will be monitored and incorporated into the equipment evaluation as part of the normal EQ Program.

The existing qualification of all components in the EQ Program was reviewed for impact due to the changes in environment, both normal and post-accident, due to the power uprate. As stated in PUSAR 10.3, all existing EQ equipment is qualified for the power uprate conditions, because the as-tested profiles for pressure, temperature, humidity and radiation bound the power uprate conditions. However, as part of implementation of power uprate, the demonstration of that qualification in the existing EQ files for each component needs to be documented, similar to the Drywell electical penetration example given above.

7. In Section 10.3.1.2, the licensee stated that the normal dose in the reactor water cleanup (RWCU) Heat Exchange Room and RWCU Pump Room increases for the EPU. However, the EPU total dose (i.e., normal and accident) in these rooms is bounded by the current dose level used to qualify all components potentially affected by this increase. It appears that the total dose will increase (40% increase in normal dose). Provide explanation why the total dose is still bounded.

DAEC Response:

While the normal doses do increase significantly (as given in PUSAR Table 10-2), the post-accident dose in the RWCU Heat Exchanger and Pump Rooms do not change due to power uprate. However, the equipment in these rooms remains qualified because their as-tested qualification for Total Integrated Dose (TID) exceeds the power uprate values. For example, for the RWCU Heat Exchanger Room, which has a 40% increase in normal dose, the calculated TID is 8.34 E+06 rads. The minimum as-tested TID for equipment in that room is 2.0 E+07 rads. So the power uprate condition is bounded by the existing as-tested qualification for TID.

8. In Section 9.3.2, the licensee stated that the EPU dacay heat analysis assumes an operating history of 100 days and 100% power, which is consistent with Regulatory Guide 1.155, section 3.2.1. Please clarify 100% power (Is it due to EPU which is 1912 MWt?).

DAEC Response:

The EPU analysis of Station Blackout, as summarized in Section 9.3.2, was performed assuming the 100% power level to be 1912 MWt.

9. Table 6-1, Page 6-14, Main Transformer Rating (MVA) is ≥ 715,225. This may be a typo, since Generator rated Output is 715 MVA.

DAEC Response:

Yes, the value in the Table contains a typographical error. The correct value should be ≥ 715.225 MVA (or, alternatively, ≥ 715,225 kVA).

DAEC Responses to Additional Questions
Received from the NRC Electrical Systems Branch

1) What is the EPU-related electrical output (MWe)?

DAEC Response:

The net plant EPU-related output will be 677 MWe (697,150 KVA with a power factor (PF) of 0.97).

2) Provide the ratings of the following:

DAEC Response:

Component	EPU Phase I 1658 MWt to 1790 MWt	EPU Phase II 1790 MWt to 1912 MWt
a. Main Generator	715,225 KVA, 18770 Amps, 22 KV	No Change
b. Main Transformer	660,000 KVA 22 KV /161 KV	>715,000 KVA 22 KV / 161 KV
c. Isolated Phase Bus	18,000 Amps 22 KV	20,000 Amps 22 KV
d. Generator Breakers (2)	2500 Amps 161 KV	No Change

3) Provide details about the modifications (Isophase Bus, Main Transformer, Generator Breaker, and Other Switchyard Equipment if required.)

Isophase Bus	No modifications are required for EPU Phase I. Phase II: modifications to increase the ampacity to approximately 20,000 amps and improve the bus cooling unit's heat removal capacity.
Main Transformer	Phase I: New Oil Cooling Units allowed re-rating of the existing transformer from 600 MVA to 660 MVA. Phase II: replacement of the transformer will be necessary to accommodate full uprated power output.
Generator Breakers	No modifications required.
Main Generator	Phase I: Replacement of the hydrogen cooling units to improve heat removal capability that will accommodate full uprated power production.
Other Switchyard Mods	A 40 MVAR capacitor bank is planned for installation in the switchyard in the Fall of 2001 to partially compensate for the loss of reactive power capability of the Main Generator due to Power Uprate.

Note on modifications: Only the modifications needed for EPU Phase I to allow operation at 1790 MWt (approx. 641 MWe) are being performed during RFO 17/Cycle18. The balance of the modifications needed for operation at 1912 MWt (Phase II) will be performed during future cycles.

Figure 1 – DAEC Drywell Temperature Profiles