Advanced Power Ultra-Uprates of Existing Plants (APUU)

U. S. Department of Energy

Research Grant Number: DE-FC07-03ID14535

FINAL SCIENTIFIC/TECHNICAL REPORT

REPORT NUMBER: STD-TFNE-06-10

March 31, 2006

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ABSTRACT

This project assessed the feasibility of a Power Ultra-Uprate on an existing nuclear plant. The study determined the technical and design limitations of the current components, both inside and outside the containment. Based on the identified plant bottlenecks, the design changes for major pieces of equipment required to meet the Power Ultra-Uprate throughput were determined. Costs for modified pieces of equipment and for change-out and disposal of the replaced equipment were evaluated. These costs were then used to develop capital, fuel and operating and maintenance cost estimates for the Power Ultra-Uprate plant. The cost evaluation indicates that the largest cost components are the replacement of power (during the outage required for the uprate) and the new fuel loading. Based on these results, the study concluded that, for a “standard” 4-loop plant, the proposed Power Ultra-Uprate is technically feasible. However, the power uprate is likely to be more expensive than the cost (per Kw electric installed) of a new plant when large capacity uprates are considered (>25%). Nevertheless, the concept of the Power Ultra-Uprate may be an attractive option for specific nuclear power plants where a large margin exists in the steam and power conversion system or where medium power increases (~.600 MWe) are needed. The results of the study suggest that development efforts on fuel technologies for current nuclear power plants should be oriented towards improving the fuel performance (fretting-wear, corrosion, uranium load, manufacturing, safety) required to achieve higher burnup rather focusing on potential increases in the fuel thermal output.

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EXECUTIVE SUMMARY

The purpose of this project was to assess the feasibility of a Power Ultra-Uprate on an existing nuclear plant. Current power uprates of Nuclear Power Plants (NPP) can be divided into three categories:

1. Measurement Uncertainty Recapture Power Uprates ~1-2% (MURPU);
2. Stretch Power Uprates up to ~5-7% (SPU); and,
3. Extended Power Uprates of > 7% (EPU).

Most of the uprates in PWRs have been of MURPU and SPU types. The successful accomplishment of these power uprates has significantly increased the total power of the fleet of PWRs. Recently, EPU's have become very attractive for the utilities as there is a large economic incentive. However, current technology limits the EPU in a PWR to 10~20%. The motivation for this project was, therefore, to evaluate how new enabling technologies may increase this value and whether it is economically attractive.

Current research and development efforts related to technologies that may enable large reactor power uprates and that were considered in this project are comprised in three main areas:

- Fuel technologies:
    - New fuel geometries, such as annular fuel rods and grid-less fuel assemblies. Annular fuel may allow fewer fuel rods with 60% more cooling surface, thus improving the thermal margin and potentially enabling increases of the power extracted from the fuel rods of up to 50%.
    - Advance cladding materials, such as ceramic cladding. An example of ceramic cladding is SiC which has better thermal and mechanics properties than Zirconium alloys (lower thermal neutron cross-section, higher operating temperature, better compressive strength and lower levels of corrosion). The better thermal and mechanics properties of these advanced alloys could thus improve core thermal margins and fuel performance in transient and severe accident conditions allowing moderate power uprates.
    - Advance fuel pellet materials having better properties. Uranium Nitride (UN) has, for example, higher thermal conductivity, lower heat capacity and swelling than UO_2. It may allow higher heavy metal loading and improve the fuel management.
- NSSS components: The energy density and performance of some NSSS components, such as Steam Generators or pumps, have been significantly improved.
- Balance of Plant (BOP): Performance of turbines and other BOP equipment has also been improved in the last decades.

The potential improvements and margins that may arise from the implementation of these technologies were used as a reference for the evaluation. This report acknowledges that some of the above technologies are not mature since there are still technical challenges that have to be addressed (e.g., manufacturing, licensing, etc.). However, a feasibility study of these technologies was not part of the scope of the evaluation and the Power Ultra-Uprate evaluation was kept, as much as possible, independent from any particular technology. An optimistic scenario approach was taken by assuming that all the technical challenges associated with the above technologies can be solved and that at least the moderate benefits expected from these technologies were achievable in the medium term. The economic value of the Power Ultra-Uprate was evaluated under these assumptions.

The Power Ultra-Uprate considered in this study has a target value between 25% and 50% and the following general characteristics:

- Same containment, reactor vessel and majority of current piping
- Plant operates as normal except for one major outage that allowed performing:
    - In-containment changes
    - Auxiliary system modifications
    - Connection of added Balance Of Plant (BOP)
- To maintain and improve current margins, upgrade or replacement of the fuel, the steam generators and part of the BOP will be required

In addition to considerations regarding the technical feasibility of a large uprate, an important aspect that has to be considered is the economic value. Market data suggests that in order to make the ultra-power uprate financially attractive to the utility, its cost has to be kept within the range of the following industry reference costs:

- $1200-$2200/kWe for new plant construction
- $600/kWe for Upgrade programs
- $600-$800/kWe for gas fired combined cycle plants

A realistic economic evaluation of the uprate should also take into account the effects on the return of investment by: (1) the years of operational life remaining after the uprate; and, (2) the future evolution of the markets.

From the point of view of the NPP vendor, the incentives to consider when performing such large uprates are various and include the supply of: (1) new core internals for annular rods with neutron reflectors; (2) new UN fuel and annular pellets; (3) new steam generators; (4) control systems; and, (5) license amendments.

Due to the diversity of the design characteristics of the operating plants in the U.S., a “standard” Westinghouse Electric Company (WEC) 4-loop, 3425 MW(t)

NSSS, plant with a dry containment was selected to be the reference design for evaluating the feasibility of achieving a Power Ultra-Uprate. The Baseline Plant NSSS Thermal Design Parameters were defined for the selected "standard" Westinghouse (W) 4-loop plant (see Section 2). Since the evaluation of the Power Ultra-Uprate was jointly performed by Westinghouse Electric Company LLC (WEC) and the Electric Power Research Institute (EPRI), the following split of the Scope of Work (SOW) was defined for the team (Section 3):

(1) WEC: evaluation of the changes required in nuclear island components;

(2) EPRI: evaluation of all the components outside of the nuclear island.

A copy of the EPRI Final Report is attached as Appendix II. The description of the tasks proposed in this program is summarized in the following table:

ID	Task / Milestone Description	Lead Organization(s)
1	**Identify baseline plant parameters**	Westinghouse & EPRI
2	**Identify nuclear island bottlenecks and proposed solutions** 2.1 Identification of the nuclear island bottlenecks 2.2 Selection of potential solutions 2.3 Evaluation of the potential solutions based on the safety and design considerations 2.4 Determination of a roadmap for the uprate 2.5 Economic evaluation of the uprate 2.6 Conclusions of the study	Westinghouse
3	**Identify BOP bottlenecks and proposed solutions** 3.1 Transmission effects analysis 3.2 Identification of major impediments to uprate 3.3 Definition of problem boundaries and constraints and alternate paths for resolution 3.4 Ranking of importance of issues and cost resolution 3.5 Final report to Westinghouse	EPRI
4	**Identify license and accident issues** 4.1 Consideration of Non-LOCA transients 4.2 Consideration of LOCA transients 4.3 Dose considerations 4.4 Containment evaluation 4.5 Identification of licensing issues 4.6 Conclusions of the study	Westinghouse
5	**Issue final report**	Westinghouse

From the above list, only task 4.5 was not completed since the uncertainties associated with some of the technologies (involved in the Power Ultra-Uprate) and the licensing process itself make it difficult to evaluate and to identify the potential licensing issues.

In the first phase of the program, the technical barriers for the Power Ultra-Uprate in a nuclear power plant (called bottlenecks in this report), were identified together with a set of tentative solutions. The identified NPP bottlenecks can be grouped in the following categories:

- Increasing the energy densities in all nuclear island components:
    - Fuel/Core: acceptance and First Time Engineering for annular and UN fuel and to increase energy density in Reactor vessel, Departure from Nucleate Boiling (DNB) and Reactor Pressure Vessel (RPV) fluence
    - Steam generator: energy balance (Thot, Tcold, steam pressure), increase heat transfer (area or efficiency)
- Handling of increased energy density of the Nuclear Steam Supply System (NSSS) during normal operation and accident conditions:
    - Capacity of Pressurizer
    - Reactor Coolant Pumps
    - Piping
    - Containment
    - Instrumentation and Control
- Handling of increased energy production by both the on-site and off-site BOP facilities:
    - Turbine and Generator
    - Condenser and Cooling Tower
    - Circulation Pumps
    - Steam line and feed-water line flow velocities
- Licensing / Acceptance:
    - Safety analysis margin has be maintained
    - Site permit limits
    - Spent fuel pool
    - Source term
    - Backfit versus new licensing criteria
- Achieving favorable economics with capital charges about equal to combined cycle gas turbine plants and combined fuel and O&M charges less than current Generation II plants.

The above list is a summary. The complete list is presented in Section 4 of this report. Note also that some of the bottlenecks may affect more than one of the categories.

Based on the identified NPP bottlenecks and the defined general characteristics of the Power Ultra-Uprate, the following strategy was adopted for performing the power uprate:

- Same reactor vessel.
- Use of new core internals with reflectors to reduce the vessel fluence and improve the neutron economy.

- Introduction of a new fuel having increased thermal margins (e.g., DNB) and thus enabling higher power density.
- Replacement of the current steam generators by new steam generators having a higher energy density (triangular pitch).
- Replace the reactor coolant pumps only requirements exceed the current specifications of the baseline plant. Parameters of importance are the pressure drop caused by the new fuel design, DNB margin, outlet core temperature (maximum is limited by corrosion), inlet core temperature (lower temperature degrade overall NPP efficiency) and maximum pump power. Final solution depends on the Power Ultra-Uprate value: 25 % or 50 %.
- Maintain the peak pressure in the containment below the current design pressure to avoid any changes to the containment structure.
- Minimize the changes in the loop piping. However, some pipes will have to be replaced due to flow rates increases that will likely increase corrosion/erosion and pressure drops.
- Add-on a second BOP in parallel with the original. As a result of the evaluation, it was found that uprating the BOP is not practical in the targeted range of power uprates.
- License amendment during planning stage.
- Plant operates as normal except for extended shutdown to make in-containment changes, connect BOP and other system changes. The length of the outage has a large impact on the economic balance of the uprate and requires carefully preparation to minimize risk, time and cost.

The evaluation of the proposed strategy for Power Ultra-Uprate (see Section 9) was mainly focused in the following areas: (1) fuel performance; (2) steam generators; (3) safety assessment; (4) auxiliary systems; (5) balance of plant; and, (6) economic evaluation. The results of these analyses are discussed in Sections 5 through 10 and Appendix II of the report. A brief summary is provided in the following paragraphs.

1) <u>Fuel performance</u> (see Section 5): The uprated Reactor Coolant System (RCS) parameters, including the outlet and inlet reactor vessel temperatures (called Tcold and Thot, respectively) and the RCS flow rate, were determined for the two targeted Power Ultra-Uprates (25 % and 50 %) and two possible scenarios:

- <u>Reactor Coolant Pumps (RCPs) are not replaced</u>: flow rate determined by the RCS losses and the current RCP developed head vs. flow rate curve characteristics; and,
- <u>Reactor coolant pumps are replaced</u>: maximum pump power is limited based on current RCP technology.

Annular fuel rods were used as the reference fuel design and a simplified steady state RCS model was employed in the evaluation. This model was used to determine the inlet conditions of a VIPRE-01 whole core model for DNB analysis of the annular fuel design. The DNB analysis was performed through a steady-state analysis with conservative conditions (18% overpower and 2°C increased coolant inlet temperature) in an effort to address the spectrum of Condition I and Condition II events. DNB for both the inner and outer channels were calculated and acceptance criterion was set to obtain a MDNBR larger than 1.3 for both the inner and outer channels. The maximum outlet vessel temperature was fixed to the current value to prevent increased corrosion concerns in the upper head of the reactor vessel and pipes. Two different 13x13 annular fuel designs and standard fuel were evaluated. The study concluded that:

- Power Ultra-Uprate 25%: Acceptable DNB margins were obtained without replacing the pumps by increasing ΔT and lowering Thot
- Power Ultra-Uprate 50%: Sufficient DNB margin is obtained only if RCPs are replaced and pump power is doubled.

2) Steam generators (see Section 6): The Westinghouse Delta 75 Steam Generator (SG) design was selected for this feasibility assessment of ultra power uprates (UPUs). Delta 75 SG has ~57% more heat transfer area and is operated at the same thermal power level as the original steam generator. Critical potential issues resulting from the operation at uprated powers were assessed using a Westinghouse proprietary code (GENF) including:

- Steam Pressure and Steam Flow rate;
- Circulation ratio and total flow through the tube bundle;
- Thermal cycle efficiency; and,
- Operational issues: (1) tubing corrosion; (2) hydrodynamic instability; (3) erosion-corrosion of feedwater distribution system; (4) flow induced tube vibration; and, (5) excessive moisture carryover.

As a result of this study, the following potential issues of Delta 75 under ultra power uprates were identified and solutions were proposed:

Bottleneck	Resolution	Prob. Of Solution
Erosion-corrosion of feed water flow system	3-D velocity analysis and evaluate whether need to have chrome content in steel	High
Local dry-out in tube bundle	DNB evaluation via 3-D T/H analysis	High
Flow induced tube vibration	Tube vibration & wear evaluation; modify tube support, if needed	High

None of the above issues are considered a potential stopper for the Power Ultra-Uprate.

3) <u>Safety Assessment</u> (see Section 7): The safety assessment included the review of various Reactor Coolant System (RCS) overpressure events (i.e., Turbine Trip, Load Rejection, etc.). From this assessment it was concluded that the uprate plant will require: (1) a larger Pressurizer (PZR) with increased steam space to absorb the higher insurge rate; and, (2) new safety and relief valves with increased capacity. The review of other events concluded the following:

- Increase in Auxiliary Feed-Water (AFW) flow is required for sufficient decay heat removal capability.
- Higher peak fuel pellet average enthalpy during reactivity insertion accidents (RIAs) (even assuming no increase in fuel stored energy and same DNB margins). This may be addressed by improving the evaluation methodology.
- Anticipated Transient Without Scram (ATWS) considerations suggest the need to install a Diverse Scram actuation System (DSS).
- Increased injection flow required for acceptable response to small and large break Loss-of-Coolant Accidents (SBLOCA and LBLOCA).
- Dose concerns can be addressed by refinement of current evaluation models and through use of Alternative Source Term (AST) methodology.

Another important item was the containment response in the uprated plant. Even with a small to no increase in Reactor Coolant System (RCS) and Steam Generator (SG) water inventories, increased Auxiliary Feed-Water (AFW) flows will result in larger mass and energy release following a steamline break event. Increased decay heat must be matched by the long term containment heat removal capability. The preliminary analysis suggested that containment response can be improved with less conservative evaluation models. The overall conclusion of the safety assessment was that there are no technical stoppers for the Power Ultra-Uprate.

4) <u>Auxiliary Systems</u> (see Section 8): The assessment of the potential modifications required in the auxiliary systems of the uprated NPP was performed using the Callaway Nuclear Plant (Standardized Nuclear Unit Power Plant Systems type or SNUPPS) as the reference plant. Key fluid system functions reviewed included:

- <u>RCS cooldown (normal and safety grade)</u>: No equipment modifications for an uprate in plant output to 150% of nominal is required since the reference plant component and essential cooling water systems are over-designed. In order to adjust for the increased decay heat of the uprate plant, the Residual Heat Removal (RHR) flow could be maintained at reference plant conditions with increased Component Cooling Water (CCW) to RHR Heat Exchanger (HX) and the normal refueling cooldown extended to 27 hrs with the safety grade cooldown achieved in 40 hrs.

- Post-accident safety injection: The assessment indicated an injection phase flow rate increase is required to maintain equivalent small and large break margins:
    - o *Small break LOCA*: Intermediate Head Safety Injection (IHSI) pump capacity has to be increased from 650 gpm to 2000 gpm at runout. Low-Head Safety Injection (LHSI) and High-Head Safety Injection (HHSI) pumps do not require any change. This minimizes piping impact.
    - o *Large break LOCA*: injection phase flow has to be increased: IHSI pumps plus the optimization of the Safety Injection (SI) accumulator. The recirculation phase flow is decreased but exceeds core boil-off rate and provides sufficient core reflooding rate. In this case, the LHSI (RHR) pumps act only as booster for the HHSI and the IHSI pumps. Note that a large IHSI pumps will impact Diesel Generator (DG) sizing.
- Post-accident containment Reactor Vessel (RV)_ heat removal: The reference plant containment and heat removal capacity is sufficient for a 50% uprate in power. Current CV peak pressure is ~50 psig vs. 60 psig design pressure. RCS sensible heat increase resulting from the uprate (larger pressurizer) can be accommodated in the current plant. No significant increase in the SG sensible heat is expected to occur since a more compact (higher energy density) SG design is proposed for the uprate and average operating temperature should be slightly lower than the current one. It was found that containment fan coolers, sprays, CCWS and ESWS can remove 5.5E8 Btu/hr operating at 47 psig.
- Post-accident and transient SG cooling (AFWS & steam relief): In order to perform this function, the uprated reference plant auxiliary feed water system requires upgrading. The use of four pumps (2 MD + 2 TD pumps) in the Auxiliary FeedWater System (AFWS) is recommended. This option minimizes impact on Diesel Generators (DGs) and improves overall plant reliability.
- Spent Fuel Pit (SFP) cooling: The heat removal capability of the SFP Heat Exchangers (HXs) must be increased significantly for the large uprate power levels. Plate HXs can be installed to significantly increase SFP Heat Exchanger (HX) heat transfer surface area. It was found that the Component Cooling Water (CCW) & Emergency Service Water (ESW) capabilities of the reference plant are sufficient. The largest targeted Power Ultra-Uprate (50%) can be accommodated with only HX and its local piping changes.

Other auxiliary fluid system functions: Chemical and Volume Control System (CVC), Boron Recycle System (BRS) and Waste Processing System (WPS) were considered but were not impacted by the Power Ultra-Uprate. No technical stoppers were found.

5) Balance of Plant (BOP) (see Appendix II): In addition to the overall evaluation of the Power Ultra-Uprate impact on the BOP, EPRI assessed the impact of a large power uprate on the existing transmission lines. The results of this study indicated that existing transmission capacities for most selected plants are sufficient for the 50% uprate (assuming all transformer/lines in service). However some plants may require an upgrade of the transmission lines to meet the Ultra-Power Uprate (UPU) operating requirements. In addition, potential reactive power supply and voltage problems were identified in some cases when the nuclear generators are not in operation. The evaluation of the existing transmission lines indicated that the need for spinning reserve could limit the uprate level in some regions. The cost associated with the upgrade of the transmission lines will probably preclude the uprate and thus reduces the potential plants as a candidate for the Power Ultra-Uprate.

The analysis of the impact of the Power Ultra-Uprate on the BOP was performed considering the multiple aspects of the problem. The conclusions of the analysis are summarized and grouped according to two general categories:

(1) Related to the replacement or modification of components of the BOP:

- The assessment of the current components of the secondary system indicates that no margin exists for the turbine/generator system. Two uprate strategies were considered:
    - Uprating the High Pressure (HP) & Low Pressure (LP) turbines and Generator
    - Building a new Turbine/Generator (T/G) building for the uprated power (i.e., 25 % and 50%)

  The cost of uprating an existing T/G is almost equal to building a new T/G building. For this reason, a new T/G building was preferred for the targeted power uprates.
- The preferred option, i.e., a new Turbine/Generator building requires:
    - Rearrangement of existing circulating water lines; and,
    - Rearrangement or construction of some buildings and tanks.

  Performing these operations will require careful planning to avoid a large impact on plant operation and outage lengths.
- The increased power of some NSSS/BOP components (e.g., RCS pumps) will require the replacement of some in-containment power cables and larger electrical penetrations.
- Increased diameter steam lines are probably needed to minimize pressure drop increases. Note that this may impact the containment structure.
- Feed water lines may require replacement depending on current corrosion issues.
- In some plants, the containment hatches may limit the maximum size of the components that can fit through them.

- The availability of adequate cooling sources was identified as a key concern for nearly all the plants. This technical limitation can be addressed through the construction of cooling towers to provide additional cooling capability but it will increase the uprate cost.

(2) Related to the plant operation and cost:

- The evaluation indicated that the outage duration (for the uprate operation) is not significantly different for 25% and 50% uprate levels. This economically penalizes the 25% power uprate with respect to the 50% uprate since the costs associated to the outage represent a large fraction of the overall Power Ultra-Uprate costs (See Section 10).
- In order to reduce the transition outage time, the largest possible number of operations associated with the Power Ultra-Uprate should be performed during refueling outages prior to the major transition (probably the three outages before the major transition).
- The startup testing requirements will likely be close to those of a new plant and thus increase the major outage lengths and associated risk and costs.
- Cycle length effects: shorter fuel cycles will reduce the capacity factor unless offset by the use of a higher uranium load, such as is available with UN fuel. This will have a significant impact on the electric generation costs.
- The reduction of efficiency arising from the new set of RCS parameters will have a moderate impact on the generation costs.

The analysis of the BOP concluded that no technical stopper exists for the Power Ultra-Uprate concept. However, due to the non-existent margins on the turbine and low pressure turbine, the preferred option for the BOP uprate is to build a new Turbine/Generator building for the added power. In addition, the option of complete replacement of the secondary (i.e., building a entire new secondary system) was rejected since no substantial savings will accrue from existing secondary system equipment (indeed most of them will not reach the end of the life but will be replaced rather than being uprated). These results will have a large impact in the economic aspects of the uprate as discussed in Section 10. Note that the EPRI contribution to this program is provided as the separate report contained in Appendix II.

5) <u>Economic evaluation</u> (see Section 10): A simplified economic evaluation for the Power Ultra-Uprate was adopted in this study. Major cost estimation assumptions were:

- Some of the work required for the uprate is done during outages preceding the transition outage and in parallel with other normal outage operations.
- Conversion of major reactor components is done during a relatively long transition outage.
- The evaluation included the cost of the replacement energy and the removal cost of major radioactive components.

- The overnight costs associated with actual plant modifications, labor, and hardware procurements were used in the evaluation.
- Replacement of the steam generators and the control system was assumed although some plants will have already replaced both.

The costs for modified pieces of equipment and for the change-out and disposal of the replaced equipment were evaluated. These costs were then used to develop capital, fuel and O&M cost estimates for the Power Ultra-Uprate plant. The costs were calculated using the present industry target cost values and thus they are referred in this report as a fraction of the industry target goal for a new plant. Despite the above approximations, the economic evaluation was judged to have sufficient accuracy for the purpose of this preliminary evaluation. The results of the evaluation for the 25% and 50% Power Ultra-Uprates are summarized in the following table:

	25 % Power Uprate	50% Power Uprate
Total Direct Costs	26 %	46 %
Total Indirect Costs	15 %	20 %
Owners Costs	29 %	10 %
Replacement Power (12 months)	23 %	18 %
Fuel Cost	7 %	6 %
Overnight Cost versus Industry Goal of 1,000 $/KWe	2.9 times	1.8 times

The cost evaluation indicates that the largest cost components are the replacement of power (during the outage required for the uprate) and the new fuel loading. The preferred option for the BOP uprate (to build a new Turbine/Generator building for the added power) has a large negative impact in the economic aspects of the uprate. In particular, the cost per installed kilowatt of the added components will be relatively large due to the relatively poor economy of scale (25 to 50% of total). Based on these results, the study concludes, in Section 10, that for a "standard" 4-loop plant, the proposed Power Ultra-Uprate is technically feasible. However, the power uprate is likely to be more expensive than the cost (per Kw electric installed) of a new plant when the large capacity uprate is considered (50%). Nevertheless, the concept of the Power Ultra-Uprate may be an attractive option for specific nuclear power plants where a large margin exists in the steam and power conversion system (BOP). The conclusions of the study suggest that development efforts on fuel technologies for current nuclear power plants should be oriented towards improving the fuel performance (FW, corrosion, uranium load, manufacturing, safety) required to achieve higher burnup rather than focusing on potential increases in the fuel thermal output.

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LIST OF ACRONYMS

AFW	Auxiliary Feed-Water
AFWS	Auxiliary Feed Water System
APUU	Advance Power Ultra-Uprate
AST	Alternative Source Term
BOP	Balance of Plant
BRS	Boron Recycle System
CCW	Component Cooling Water
CCWS	Component Cooling Water System
CVCS	Chemical and Volume Control System
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio
DG	Diesel Generator
DSS	Diverse Scram actuation System
EPU	Extended Power Uprates
EPRI	Electric Power Research Institute
ESW	Emergency Service Water
ESWS	Emergency Service Water System
HHSI	High-Head Safety Injection
HP	High Pressure
HX	Heat Exchanger
IHSI	Intermediate Head Safety Injection
IRC	Inside Reactor Containment
LBLOCA	Large Break Loss-of-Coolant Accident
LHSI	Low-Head Safety Injection
LOCA	Loss-of-Coolant Accident
LP	Low Pressure
MDNBR	Minimum Departure from Nucleate Boiling Ratio
MURPU	Measurement Uncertainty Recapture Power Uprate
MFW	Main Feed Water
MIT	Massachusetts Institute of Technology

MSLB	Main Steam Line Break
NERI	Nuclear Energy Research Initiative
NPP	Nuclear Power Plant
NSSS	Nuclear Steam Supply System
O&M	Operation and Maintenance
ORC	Outside Reactor Containment
PWR	Pressurized Water Reactor
PZR	Pressurizer
RCP	Reactor Coolant Pump
RHR	Residual Heat Removal
RHRS	Residual Heat Removal System
RIA	Reactivity Insertion Accident
RPV	Reactor Pressure Vessel
RV	Reactor Vessel
SBLOCA	Small Break Loss-of-Coolant Accident
SI	Safety Injection
SiC	Silicon Carbide
SFP	Spent Fuel Pit
SG	Steam Generator
SLB	Steam Line Break
SNUPPS	Standardized Nuclear Unit Power Plant Systems
SPU	Stretch Power Uprates
SOW	Scope of Work
T/G	Turbine/Generator
UHS	Ultimate Heat Sink
UN	Uranium Nitride
UO2	Uranium Dioxide
UU	Ultra-Uprate
UPU	Ultra Power Uprates
WPS	Waste Processing System
WEC	Westinghouse Electric Company

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1 Introduction

Over the last 20 years, small uprates (<10%) and better operating practices at the nuclear utilities have raised plant availability from the 75% range in the 1970's to around 95% today. This has resulted in additional nuclear generated electric power equivalent to the output of roughly 20 new 1,000 MWe plants. Further major increases, however, will require increases in the power density of the reactor cores. This will be difficult without exceeding such core design standards as the minimum departure from nucleate boiling ratio (DNBR).

New technologies that can be applied to the Pressurized Water Reactor (PWR) portion of the nuclear fleet have been developed that may allow significant increases in power density. For instance, an annular fuel design (see Figure 1.1) has been developed by the Massachusetts Institute of Technology (MIT) as part of the Nuclear Energy Research Initiative (NERI) Project 01-005 (High Performance Fuel Design for Next Generation PWRs, Contract Number DE-FG03-01SF22329) that increases the fuel surface area by 60% or more. The use of triangular pitch replacement steam generators has demonstrated the capability of increasing tube surface areas by at least 50%. New fuel internals designs that allow the use of 14 foot instead of the more standard 12 foot fuel rods increase the fuel density from the low 90's to above 96.5% and provide the capability to increase the amount of uranium in the core.

In a study jointly headed by the Electric Power Research Institute (EPRI) and Westinghouse Electric Company LLC (WEC), funded by the Department of Energy (Contract Number DE-FC07-03ID14535), EPRI and WEC determined the technical challenges and the economics in utilizing these technologies to achieve very large uprates (up to 50%, termed an Ultra-Uprate or UU in this study) of current Generation II PWR plants. Specific objectives of the project were:

1. Identify market needs for up to 50% uprates of current plants.
2. Identify both nuclear and non-nuclear component constraints for current plants.
3. Verify the technical feasibility of up to 50% uprates.
4. Generate estimates for the installed capital, fuel and O&M costs, as well as an estimate of the licensing costs and times.
5. Identify the long-term development needs for this technology including time and costs.

The Ultra-Uprate approach proposes to build the nuclear island components and balance of plant (BOP) facilities in parallel with normal plant operation. It is envisioned that the new nuclear components (steam generators, new core internals, and other items, such as replacement of the current plant control wiring) are installed during a 6 to 12-months window, much as replacement steam generators are today. The BOP items would also be tied in at this time. This would minimize the downtime that the plant is not producing revenue.

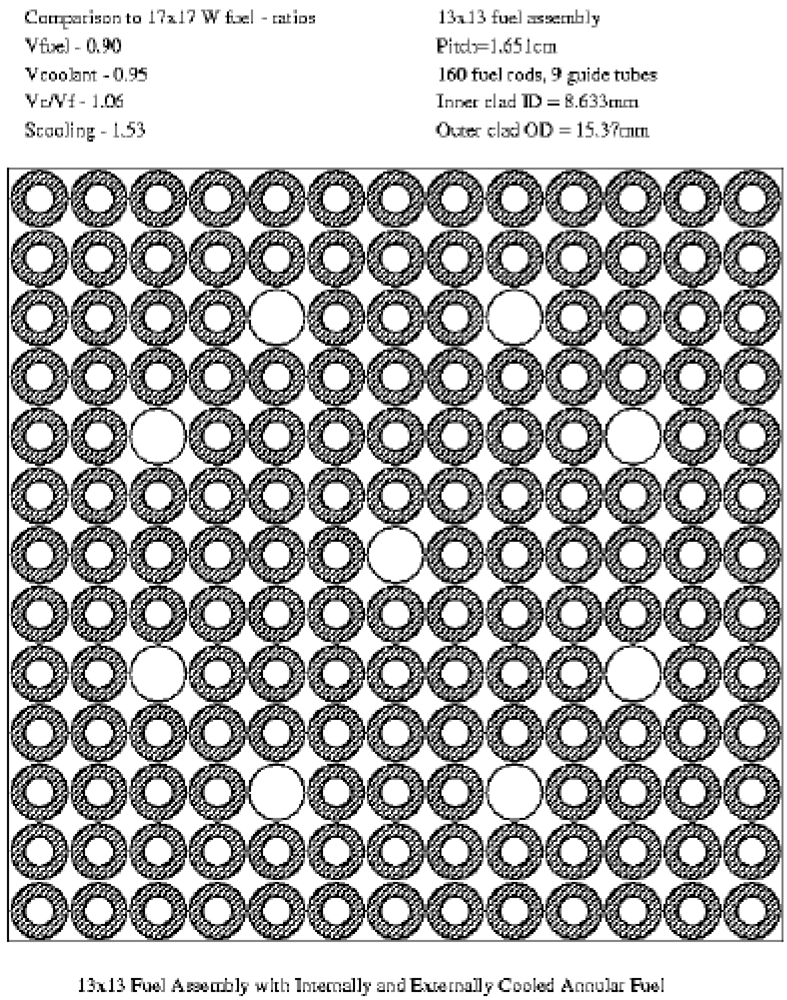

Figure 1.1 - Annular Fuel Assembly Schematic.

Some of the barriers to be overcome include:

1. Increases in energy densities in all nuclear island components.
2. Handling of the results of the increased energy density during accident conditions.
3. Handling of the increased energy production by both the on-site and off-site BOP facilities.
4. Achieving favorable economics with capital charges about equal to those for combined cycle gas turbine plants with combined fuel and O&M charges less than or equal to current Generation II plants.

The following team participated in this program:

1. Westinghouse Electric Company LLC evaluated the changes required in nuclear island components, such as reactor internals, controls, steam generators, pressurizers and reactor coolant pumps, to meet an up to 50% power increase. Design and license limitations of the current components, both inside and outside the containment were identified. Westinghouse also provided the project management and the final report containing estimated capital and operating costs and an outline of the development program (goals, costs and times) required to bring this technology to fruition.
2. The Electric Power Research Institute (EPRI) identified critical issues, assessed their impact and provided paths to resolution for components outside of the nuclear island.
3. The Massachusetts Institute of Technology (MIT) evaluated the neutronics and thermal hydraulics of the annular fuel as an extension of their current NERI funded work.

The approach that was used in this study is as follows:

1. Current PWR nuclear plants were surveyed and a “typical” plant was selected as the baseline plant. This provided the basis on which to look at all the plant systems.
2. Next, the boundary between the Westinghouse and EPRI portions of the study were established. WEC evaluated the nuclear island components including power generation, safety, piping and structural components. EPRI evaluated components outside the nuclear island including the steam turbines, electric generators, and electrical transmission and distribution components.
3. The baseline PWR plant was then surveyed to identify potential bottlenecks for increasing capacity.
4. An evaluation was made of each of the bottlenecks and an approach to solving the bottlenecks was identified.
5. The cost and time required to implement each of the approaches was then determined.
6. Finally, an overall schedule was developed to implement the UU in the baseline PWR plant and a final overnight, installed capital cost was determined.

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2 Selection of the Baseline Plant for the Ultra-Uprate NEPO Program

Westinghouse (WEC) reviewed the operating plants in the U.S. and selected the "standard" WEC 4-loop, ~3425 MWt NSSS, plant with a dry containment to be the reference design for evaluating the feasibility of implementing an ultra-uprated power output (goal is a 50% power increase). There are 11 operating units of this type, including: Byron 1 & 2, Braidwood 1 & 2, Comanche Peak 1 & 2, Vogtle 1 & 2, Seabrook 1, Callaway, and Wolf Creek. Many of these plants were designed, constructed and/or began operation in the same time period, and they have similar containment layouts and nuclear steam supply system (NSSS) fluid systems designs. Also, as is the practice at most U.S. electric power plant sites, the reference plant utilizes a natural draft cooling tower as the power system's ultimate heat sink.

It is noted that selection of the 4-loop 3425 MWt (WEC) PWR as the ultra-uprate baseline plant will not prevent the rationale developed in this study, such as the core design requirements and component resizing/replacement bases, from being applied to other operating PWRs. For example, there are an additional 9, 3425 MWt units in the U.S. that employ ice-condenser containments. However, ice condenser plants will not be considered in this study since their smaller containment volume and limited containment design pressure may restrict some potential uprate modifications. Likewise, the uprate modifications may also be applicable to 3-loop (WEC) PWRs since they share many component design bases with the 4-loop PWRs. Thus, the results of the uprating study can be applied, at least in part, to an additional 20 to 25 PWR units in the U.S.

It is also noted that many of these 3425 MWt reactors have already pursued small (2-6%) capacity uprates that have increased their power rating to as much as ~3600 MWt. This should not pose a serious obstacle to the application of the ultra-uprate study results since all anticipated program features, such as major component resizing, will still be needed to achieve an uprating on the order of 50%.

Table 2.1 lists a set of basic thermal design parameters for a WEC 4-loop nuclear steam supply systems (NSSS). WEC used these parameters for the initial ultra-uprate evaluations. EPRI used the same baseline plant, but made their evaluation based on the electrical grid connections and other site parameters that are deemed important from the above listed plants.

Table 2.1 - WEC Baseline Plant NSSS Thermal Design Parameters.

NSSS DESIGN PARAMETER	VALUE
RCS-Primary Side Parameters	
NSSS Power (MWt)/(10^6 Btu/hr)	3425/11685
Nominal Loop Flow (gpm)	4 x 100,000
Reactor Coolant Operating Pressure (psia)	2250
Core Bypass Flow (% of Total Flow)	6
Reactor Coolant Temperatures	
Reactor Vessel Outlet (°F)	618
Reactor Vessel/Core Inlet (°F)	559
Steam Generator-Secondary Side Parameters	
Steam Temperature (°F)	545
Steam Pressure (psia)	1000
Steam Flow (10^6 lb/hr total)	15.1
Feed Water Temperature (°F)	440
Moisture in Steam (% maximum)	0.25
SG Design Pressure (psia)	1200

3 Boundary of Westinghouse and EPRI Analyses

This study was carried out by Westinghouse and EPRI with each evaluating a different portion of the power system. The second task in this analysis was to divide the scope of this study between WEC and EPRI. Major scope items were identified for each while specific tasks were determined by the responsible party.

3.1 WEC Scope - Systems/Components/Functions

- Reactor core thermal-hydraulic design
- Reactor vessel (RV) and internals
- Reactor coolant system and components (pumps, piping, steam generators, etc.)
- Inside reactor containment (IRC) safety related systems/functions:
    - Containment post-accident heat removal function
    - Containment spray system
    - Safety injection system
    - Containment recirculation sump
    - Residual heat removal system
    - Steam generator system
- Refueling operations and fuel handling
- Outside reactor containment (ORC) safety related systems/equipment:
    - Residual heat removal system
    - ORC steam generator system (to main feed and steam isolation valves)
    - Safety injection system
    - Component cooling water system
    - Essential service water system
    - Spent fuel pool cooling system

3.2 EPRI Scope - Systems/Components/Functions

- Steam and feed water heat balance
- Turbine-generator
- Main steam system (steam piping, steam dump and throttle and stop valves, moisture separator/reheater, and piping)
- Condensate system (condenser, air removal, condensate pumps, etc.)
- Main feed water system (MFW pumps, MFW heaters, piping, etc.)
- Auxiliary feed water system
- Main circulating water system
- UHS cooling tower(s)
- Turbine building component (closed) cooling water system
- Integration of steam, feed water, main circulating water, auxiliary feed water, and, essential service water systems should a second turbine-generator be employed
- Plant electrical systems and switchyard
- Emergency power supply
- Electrical transmission to users

4 Identification of Nuclear Island Bottlenecks and Proposed Solutions

An analysis was performed by Westinghouse on each of the plant systems listed in Section 3. This task was completed by a team that included expertise in:

1. Fuel performance (thermal hydraulics, neutronics and manufacturing)
2. Safety systems
3. NSSS major equipment (reactor coolant pumps, steam generators, pressurizer, and, the reactor vessel)
4. Instrumentation
5. Chemical systems
6. Emergency systems
7. Utilities

First, the major components were identified. The design and operational aspects for each component were then identified and analyzed for potential bottlenecks. Potential solutions were then identified for each bottleneck. The list of components, analyzed aspects, potential bottlenecks and solutions are shown in

Table 4.1. This list provided a task list of items that were considered in the next phase of this project. EPRI also performed a similar effort. The results are discussed in Appendix II.

Table 4.1 - List of Potential Component Bottlenecks and Potential Solutions for Westinghouse Scope.

Component	Aspect to be Analyzed	Potential Uprate Bottlenecks	Solutions
Fuel and core performance	• Thermal Design • Design Flow • Transient behavior • Control rods	• Fuel rod DNB • Fuel rod internal pressure • Core delta T • Stored energy • Flow instabilities, vibration and liftoff forces • Reactivity control and control rod (CR) mechanisms	• Annular fuel design • Other fuel design • New clad material • Uprate secondary efficiency to reduce thermal uprate
Steam generators (SG)	• Moisture separator • Steam and feed water piping • Transient behavior • Flow-induced vibration	• Heat transfer area • Flow-induced vibration • Moisture carryover • Corrosion • Steam saturation temperature • External SG size	• Triangular pitch • Redesign SG moisture separators • Evaluate corrosion/erosion at higher velocities
Reactor Coolant Pumps (RCP)	• Sizing (motor and pump) • Transient behavior	• Higher flow will increase RCS pressure losses • Reduction of safety margins	• Limit uprate to ≤125% for current pump • Pump replacement combined with a reduction of Thot
Steam Generator Isolation, Safety, PORV, and steam dump valves	• Valve size and number	• Reduction of safety margins • Corrosion/erosion • Excessive pressure drop	• Replacement • Increase the number • Evaluate corrosion/erosion at higher velocities
Reactor Vessel	• Fast neutron fluence • Internals	• Vessel fluence (PTS, welds, etc.) • Additional redesign for new fuel control rod drive mechanisms (CRDM) • Corrosion issues if higher Thot is used	• Radial reflector and/or selected shielding • Vessel annealing • Replacement of upper head and old CRDMs
Pressurizer	• Volume vs. power • Transient behavior • Reduced Average Temperature (Tavg)	• Reduction of safety margins	• Replacement
Containment	• Post-accident peak pressure and temperature	• Reduction of safety margins • Loss of coolant accident (LOCA) • Steam Line Break	• Increase heat removal capabilities • Improve safety analysis methods
NSSS structural	• Modifications necessitated by new components	• Larger Pressurizer • Water and steam piping changes	• New components will require new supports and eventually modifications to their cubicle
Chemical and Volume Control System	• No modifications were identified		
Boron Recycle System	• No modifications were identified		

Table 4.1 - List of Potential Component Bottlenecks and Potential Solutions for Westinghouse Scope (Continuation).

Component	Aspect to be Analyzed	Potential Uprate Bottlenecks	Solutions
Auxiliary Feed Water (AFW) System	• Pumps • Piping • Safety grade condensate supply	• AFW pump capacity • Higher flow rate • Higher decay heat	• Resizing • Improve reliability
Spent Fuel Handling and Storage, and Spent Fuel Pit (SFP) Cooling System	• Size and cooling requirements	• Spent pool size (shorter cycles) • Longer fuel assemblies • Adequate heat removal capability	• Maintain current fuel length or • Justify higher dose rate at pool surface • Replace SFP racks and modify fuel transfer • Resize SFP cooling system
Instrumentation	• Instrumentation • Software	• Margins	• Modification of these system, as a result of plant changes, may be required
Reactor Protection System	• System response		
Reactor Safety Analyses	• Transient • LOCA • Source Term • Licensing	• LOCA accidents • Licensing of the annular fuel	• Potential solutions are addressed through components and improved safety analysis
Safety Injection System (SIS)	• LOCA • Feed & Bleed • Boration	• Increased power will required re-analysis of SIS • If the core has higher reactivity, a high boric acid (BA) concentration could be required	• Replacement or modification of SIS components • BA used to control reactivity
Residual Heat Removal System (RHRS)	• Normal and Safety Grade Cool down	• Higher decay power	• Replacement or modification of RHRS components
Containment Spray and Fan Cooler Systems	• Containment Spray • Containment Heat removal	• Reduction of safety margins	• Resize and/or replacement of the spray, fan cooler, or modification
Emergency Electrical Power System (EEPS)	• Diesel generator (DG)	• Increase power required by upsizing of system pumps loaded onto the EEPS	• Resize or add Emergency DG capacity
Component Cooling Water (CCW) System	• Normal and safety grade cooldown • Post-accident heat removal	• Higher decay heat will require proportional increase to heat removal capability	• Re-analyze, resize, or add CCW capacity
Essential Service Water (ESW) System	• Normal and safety grade cooldown • Post-accident heat removal	• Higher decay heat will require proportional increase to heat removal capability	• Reanalyze, resize, or add ESW capacity

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5 Fuel, Core and Reactor Coolant Pump (RCP) Performance (P. Rubiolo, WEC, D. Feng, P. Hejzlar and M.S. Kazimi, MIT)

The design of the primary loop components is an iterative process. Fuel design parameters are chosen which yield a given pump power for a given temperature rise over the core. In addition, the temperature rise over the core which defines Thot and Tcold (the outlet and inlet to the reactor, respectively) also defines the performance of the u-tube steam generators. For instance, for a fixed Thot (reactor outlet temperature), the output of the reactor core can be increased if the Tcold temperature is decreased (which keeps the reactor coolant pump (RCP) power the same but lowers the efficiency of the steam generator). Another approach [1] is to keep the Tcold the same which keeps the efficiency of the steam generator constant but increases the flow and therefore dramatically increases the pressure drop throughout the primary circuit and the power required to run the RCPs. Such a flow increase (~50% above the current core flow rate) cannot be achieved in reality, since it would theoretically require that the reactor coolant pumps provide 2.25 (1.5^2) times more head and the pump motor 3.375 (1.5^3) times more power. A more reasonable approach is to use a combination of both. This task is made much more difficult by the fact that the design must fit within the current physical boundaries of the baseline nuclear plant. This section addresses this balance by first providing guidelines for the determination of the reactor cooling system (RCS) parameters required by the VIPRE model that are based on realistic limitations imposed by the pump capabilities. Then, these two scenarios are used as the basis for performing departure from nucleate boiling studies in the annular core.

The following analysts are responsible for the various parts in this section:

Pablo Rubiolo (WEC)	Overall section and Section 5.1 (Determination of the Core Parameters for Various RCP Approaches)
D. Feng, P. Hejzlar and M.S. Kazimi (MIT)	Section 5.2 (Effect of Core Parameters on DNBR)

5.1 Determination of the Core Parameters for Various RCP Approaches

Two different scenarios are considered for performing the core departure from nucleate boiling (DNB) analysis for an UU of an existing nuclear plant:

1. Case 1: The RCPs are not replaced and, thus, the RCS flow rate is determined by the RCS flow losses and the current RCP developed head vs. flow rate curve characteristics. This scenario will result in only a small increase in the core flow rate since the only significant change from the reference plant is a possible decrease in the core ΔP.
2. Case 2: The RCPs are replaced with pumps which can develop more head and flow, thus allowing more freedom for the determination of acceptable core parameters (in particular the flow rate). However, the maximum pump power is limited based on current RCP technology to about twice the current horsepower.

This section describes the optimization procedures to determine the core parameters for each of these scenarios. MATHCAD® models were developed to do the calculations and are presented in Appendix I.

The nomenclature for these thermal hydraulic models is summarized in Table 5.1. The two different scenarios are considered below for the Ultra-Uprate (UU):

5.1.1 RCPs Are Not Replaced

In this case, the RCS flow rate is determined by the loop pressure loss and the current pump characteristic head vs. flow curve. The objective is to calculate core parameters that satisfy the departure from nucleate boiling (DNB) analysis for a given core power increase (25% or 50%) over the current core power. Typically, in WEC safety analyses, a minimum DNB ratio (ratio of the DNB to the DNB limit) of 1.3 is maintained at all times. Similarly, a safety analysis limit for the DNB ratio ($DNBR_{SAL}$) is to be defined for the UU core. The calculational procedure (see Figure 5.1) is as follows:

1. Select the core thermal power (Pth):

    150%

    125%

2. Select the core outlet temperature (T_{CO_OUT}) (for example 597°K)

3. Determine the RCS mass flow rate using the pump characteristic curve and RCS flow losses (Equations 5, 7 and 10) and determine the corresponding core inlet temperature (T_{CO_IN}).

4. Perform a core DNB analysis using the VIPRE model (see Section 5.2)
5. The minimum DNB ratio (MDNBR) determined in the analysis is compared to the $DNBR_{SAL}$:
   a. If $MDNBR < DNBR_{SAL}$, then reduce T_{CO_OUT} and repeat from Step 2.
   b. If $MDNBR > DNBR_{SAL} + \Delta DNBR$, where ΔDNBR is a user selected convergence criteria, then T_{CO_OUT} is increased and the procedure is repeated from Step 2.
   c. If $DNBR_{SAL} \leq MDNBR \leq DNBR_{SAL} + \Delta DNBR$, then stop.

5.1.2 RCPs Are Replaced

In this scenario the RCPs are assumed to be replaced in order to increase the core flow rate. However, the maximum pump power is limited. Based on current technologies, the pump power limit is defined to be 2 times more than the current RCP. As in the previous procedure, a safety analysis limit for the DNBR ($DNBR_{SAL}$) has to be defined together with a convergence value ($\Delta DNBR$). The procedure (see Figure 5.2) is as follows:

1. Select Thermal Power (Pth): 150%
2. Select a T_{CO_OUT}
3. Determine the minimum T_{CO_IN} based on an RCS flow rate that does not result in an RCP power that exceeds the maximum pump power limitation (Equations 5, 9, and 11).
4. Perform DNB analysis using the VIPRE model
5. The MDNBR found in the analysis is compared against the $DNBR_{SAL}$:
   a. If $MDNBR < DNBR_{SAL}$, then reduce T_{CO_OUT} and repeat from Step 2.
   b. If $MDNBR > DNBR_{SAL} + \Delta DNBR$, then increase T_{CO_OUT} and repeat from Step 2.
   c. If $DNBR_{SAL} \leq MDNBR \leq DNBR_{SAL} + \Delta DNBR$, then stop.

Table 5.1 - Nomenclature for MATHCAD Thermal Hydraulic Models.

A_i	Flow area of RCS component *i*	ΔP_{CL}	Cold leg pressure drop (Pa)
$bypass_{CO}$	Core bypass fraction	ΔP_{VE}	Vessel pressure drop (includes core support plates) (Pa)
g	Gravity acceleration (m/sec^2)	ΔP_{CO}	Core pressure drop (excluding core support plates) (Pa)
k_i^*	Dimensionless friction coefficient	ΔP_{HL}	Hot leg pressure drop (Pa)
k_i	Friction factor ($1/m^4$)	ΔP_{SG}	Steam generator pressure drop (Pa)
k_{CL}	Cold leg friction factor ($1/m^4$)	ΔP_{PU}	Primary pumps pressure drop (Pa)
k_{RV}	Reactor vessel friction factor ($1/m^4$)	$\Delta h[Q]$	Pump head (m_{water})
k_{CO}	Core friction factor ($1/m^4$)	ρ_i	Coolant density at component *i* (kg/m^3)
k_{HL}	Hot leg friction factor ($1/m^4$)	ρ_{COLD}	Cold leg density (kg/m^3)
k_{SG}	Steam generator friction factor ($1/m^4$)	ρ_{HOT}	Hot leg density (kg/m^3)
$\dot{m}_{RCS}$	Total RCS mass flow rate (kg/sec^2)	ρ_{CO_IN}	Core inlet density (kg/m^3)
$\dot{m}_{CO}$	Core mass flow rate (kg/sec^2)	ρ_{CO_OUT}	Core outlet density (kg/m^3)
Q	Volumetric flow rate (m^3/sec)	ρ_{PU}	Water density at the pump (kg/m^3)
T_{CO_out}	Core outlet temperature (K)		
T_{CO_in}	Core inlet temperature (K)		
T_{COLD}	Cold leg temperature (K)		
T_{HOT}	Hot leg temperature (K)		
$WPUMP$	Pump power (kW)		

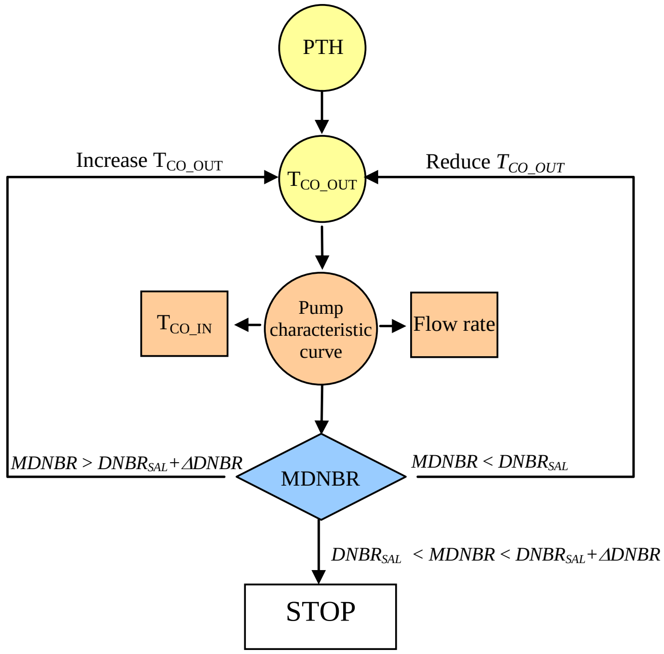

Figure 5.1 - Flow Chart for Determining the Core Flow Rate and Fluid Inlet and Outlet Temperatures When Using the Current RCPs.

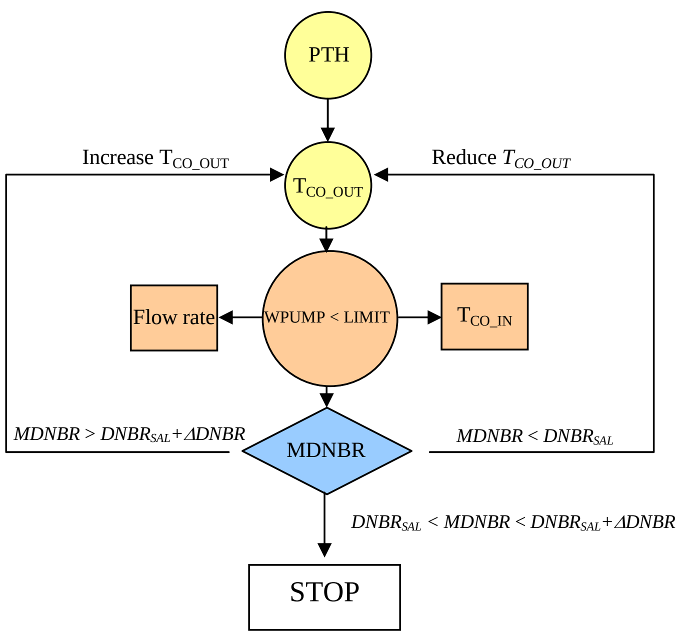

Figure 5.2- Flow Chart for Determining the Core Flow Rate and Fluid Inlet and Outlet Temperatures When Using Higher Power RCPs.

5.1.3 Reactor Coolant System Equations

The MATHCAD simplified RCS model was used to determining the temperatures and flow rate required by the VIPRE code core model. Files used in the determination of the RCS parameters are contained in Appendix I, Sections I.1 and I.2. The total steady-state pressure drop through the closed RCS is the sum of the fluid friction, elevation and acceleration terms for each component making up the flow loop. However, in single-phase flow, like PWRs, the contribution of the elevation change (including buoyancy) is nearly zero (exactly zero if isothermal). Also, the fluid acceleration losses due to flow area changes and density changes have been accounted for in the component ΔP's. Therefore the overall RCS pressure drop can be calculated to a first approximation as:

$$\Delta P = \sum_i \Delta P_i = \Delta P_{CL} + \Delta P_{HL} + \Delta P_{CO} + \Delta P_{RV} + \Delta P_{SG} = \Delta P_{PU} \tag{1}$$

where:

ΔP_{CL} :	Cold leg pressure drop, nozzles, down-comer, etc.
ΔP_{RV} :	Reactor vessel pressure drop (includes core support plates)
ΔP_{CO} :	Core pressure drop (excluding core support plates)
ΔP_{HL} :	Hot leg pressure drop
ΔP_{SG} :	Steam generator pressure drop
ΔP_{PU} :	Reactor coolant pump pressure increase

The pressure drops in the individual RCS components can be approximated as follows:

$$\begin{aligned} \Delta P_i &= \frac{1}{2} \cdot k_i^* \cdot \rho_i \cdot V_i^2 = \frac{1}{2} \cdot k_i^* \cdot \rho_i \cdot \frac{Q_i^2}{A_i^2} \\ &= \frac{1}{2} \cdot k_i \cdot \rho_i \cdot Q_i^2 = \frac{1}{2} \cdot k_i \cdot \frac{\dot{m}_i^2}{\rho_i} \end{aligned} \tag{2}$$

where k_i^* is the dimensionless friction coefficient, k_i is the friction factor expressed in [meters^{-4}] and defined as $k_i = k_i^* / A_i^2$, ρ_i is the coolant density and has to be evaluated at the fluid temperature and, $\dot{m}_i$ is the mass flow rate. Note that the friction factor k_i can be assumed to be constant for the range of the Reynolds numbers experienced in a typical RCS [2]. Table 5.2 presents the friction factors to be used to determine the pressure drops for the RCS. These factors have been determined based on information from a typical 4-loop plant and have been corrected such that they are representative of the components after the APUU. The core friction loss has to be determined by the VIPRE core model and Equation (2). A MATHCAD file implementing an example of this calculation is presented in Appendix I, Section I.4.

Table 5.2 - Typical RCS Component Friction Factors.

Component		**Value [**1/m^4**]**
Steam Generators	k_{SG}	0.939498
Cold Leg	k_{CL}	0.330773
Reactor Vessel	k_{RV}	0.548069
Core	k_{CO}	To be determined according to the core design
Hot leg	k_{HL}	0.059101

During steady state conditions, mass conservation implies that:

$$\dot{m}_i = \dot{m}_{RCS} \tag{3}$$

where $\dot{m}_{RCS}$ is the total RCS mass flow rate. Note however, that the mass flow rate through the core is reduced by the amount of the core bypass flow. Therefore:

$$\dot{m}_{CO} = (1 - bypass_{CO}) \cdot \dot{m}_{RCS} \tag{4}$$

where $bypass_{CO}$ is the core bypass fraction. In addition, the core mass flow rate $\dot{m}_{CO}$ has to satisfy the core energy balance:

$$\dot{m}_{CO} = \frac{Pth}{H[T_{CO\_out}] - H[T_{CO\_in}]} \tag{5}$$

where Pth is the core thermal power and, T_{CO_out} and T_{CO_in} are the outlet and inlet core temperatures and $H[T]$ is the specific water enthalpy. Note that due to the bypass, T_{CO_out} is higher than the hot leg temperature and can be approximated as follows:

$$T_{CO\_OUT} = \frac{T_{HOT} - T_{COLD}}{(1 - bypass_{CO})} + T_{COLD} \tag{6}$$

where T_{COLD} is the cold leg temperature and $T_{CO\_IN} = T_{COLD}$. The head versus volumetric flow curve for a single, current RCP can be expressed as:

$$\Delta h[Q] = 0.8174 \cdot Q^3 - 18.676 \cdot Q^2 + 113.46 \cdot Q - 92.004 \quad (7)$$

where Q is the pump volumetric flow rate in cubic meters per second [m^3/s] and $\Delta h[Q]$ is the pump developed head in meters of water [m]. Therefore:

$$\Delta P_{PU} = \rho_{PU} \cdot g \cdot \Delta h[Q] = \rho_{PU} \cdot g \cdot \Delta h\left[\frac{\dot{m}_{RCS}}{4 \cdot \rho_{PU}}\right] \quad (8)$$

where ρ_{PU} is the water density at the pump and g is the acceleration due to gravity. Note that Equation (7) was developed for a single RCP in a typical WEC 4-loop reactor. Therefore, the single loop flow rate, i.e., one quarter of the total RCS flow rate, has to be used in Equation (7) for evaluating the pressure increase provided by the RCPs. By inserting Equations (7) and (8) in Equation (1):

$$\sum_i \Delta P_i = \frac{1}{2} \cdot \left(\sum_i \frac{k_i}{\rho_i}\right) \cdot \dot{m}_{RCS}^2 = \rho_{PU} \cdot g \cdot \Delta h\left[\frac{\dot{m}_{RCS}}{4 \cdot \rho_{PU}}\right] \quad (9)$$

Equation (9) can be rearranged as follows:

$$\frac{k_{CL}}{\rho_{COLD}} + \frac{2 \cdot k_{CO} \cdot (1 - bypass_{CO})^2}{(\rho_{CO\_OUT} + \rho_{CO\_IN})} + \frac{2 \cdot (k_{SG} + k_{VE})}{(\rho_{COLD} + \rho_{HOT})} + \frac{k_{HL}}{\rho_{HOT}} = \frac{2 \cdot g \cdot \rho_{COLD}}{\dot{m}_{RCS}^2} \cdot \Delta h\left[\frac{\dot{m}_{RCS}}{4 \cdot \rho_{COLD}}\right] \quad (10)$$

In obtaining Equation (10), the average water density in the steam generators (SGs) and the reactor vessel was assumed to be equal to the average of the cold and hot leg densities, ρ_{COLD} and ρ_{HOT}. The effective core density is also approximated as the average of the inlet and outlet core densities, ρ_{CO_IN} and ρ_{CO_OUT}, respectively.

If the current reactor coolant pumps are retained for the power uprate (Case 1), then Equation (10) can be used to determine the RCS mass flow rate that satisfies the pump characteristic curve, Equation (7). If the primary pumps are changed (Case 2), then the limiting factor in selecting the RCS flow rate is the RCS pump power which has to be kept below two times the reference pump power:

$$\frac{WPUMP}{WPUMPREF} = \frac{\dot{m}_{RCS} / 4 \cdot \sum_i \Delta P_i}{\rho_{COLD} \cdot WPUMPREF} \le 2 \quad (11)$$

where $WPUMPREF$ is the power of the reference pump.

5.1.4 Reactor Coolant Pumps Characteristic Curve

Figure 5.3 provides a plot of a typical WEC 4-Loop reactor coolant pump (RCP) developed head (in meters of water) versus volumetric flow curve (in cubic meters per second). The curve has been fitted with the equation shown in the figure (see Appendix I, Section I.3). This curve, together with the flow resistances of the primary components of a typical 4-loop reactor coolant system (RCS), can be used to estimate the mass flow rate and core parameters for an uprated plant when the RCPs are not replaced.

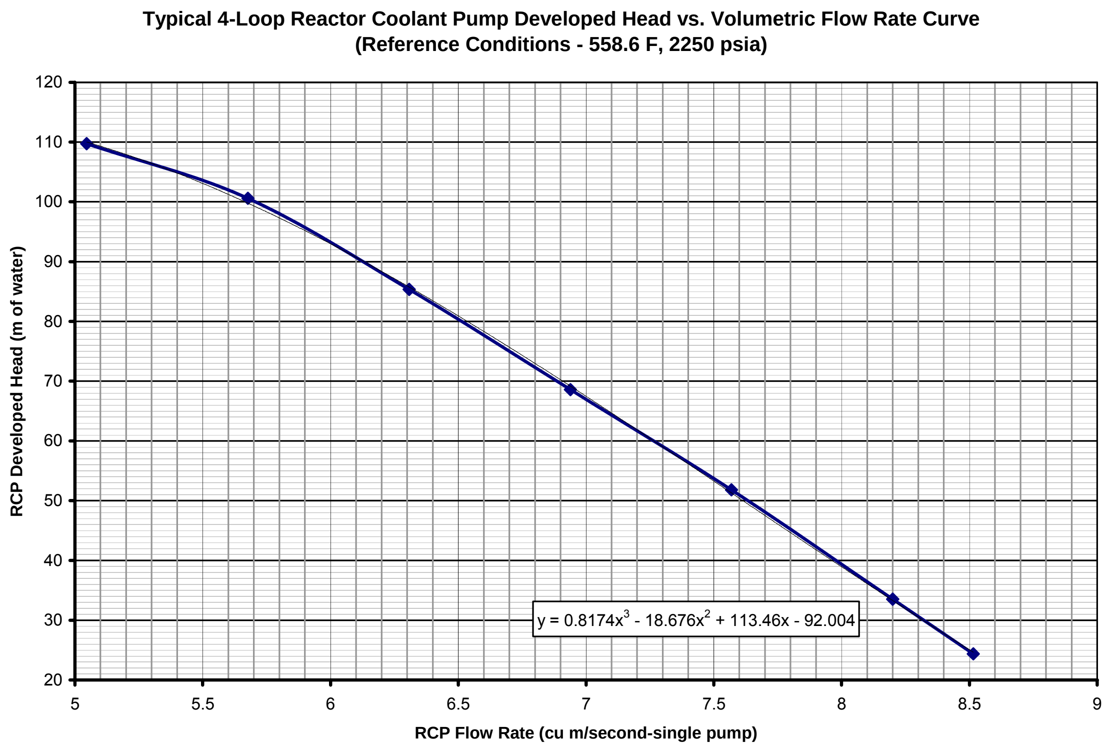

Figure 5.3 - Pump Characteristic Curve.

5.1.5 References

[1] MIT-NFC-PR-058.

[2] Tong L.S. and Weisman J., *Thermal Analysis of Pressurized Water Reactors*, p. 244 , ANS, 1996.

5.2 Effect of Core Parameters on DNBR

The purpose of this study is to evaluate the required core inlet and outlet temperatures for the flow rates consistent with the pump power restrictions, such that the MDNBR safety limit is not exceeded. The DNBR calculations are performed using VIPRE-01 annular fuel whole core model. The MDNBR safety analysis limit ($DNBR_{SAL}$) was taken to be the same as that for a regular Westinghouse 4-loop PWR having solid fuel and using the same analysis approach.

5.2.1 MDNBR Analysis Model and Assumptions

In the VIPRE-01 model, annular fuel rods that use pellet fuel are defined as heat generating tubes with five material regions that involve the inner cladding, inner gap, fuel ring, outer gap and outer cladding. The radial power factor for fuel ringl equals 1.0 and those of the other four regions equal 0.0, i.e., no neutron and gamma heating in the cladding is assumed.

The Critical Heat Flux (CHF) correlation used for inner channels is the W-3S correlation with a grid mixing factor of 0.0 (because there is no grid), and that used for the outer channels is the W-3L correlation with a grid mixing factor of 0.043, grid spacing factor of 0.066 [3], and grid factor leading coefficient of 0.986. Core parameters at a certain core power level, i.e., the core flow rate and coolant inlet temperature, were calculated by MATHCAD files provided by Westinghouse as discussed in [2] and in Section 5.1. All the DNBR calculations were performed at an 18% overpower condition to avoid analysis of the full spectrum of the Condition I and II events. The inlet temperature was increased by 2°C to account for non-uniformity due to imperfect mixing in the lower plenum. However, it is noted that the power to flow conditions which are typical for current PWRs may not be identical for the situations when RCPs are replaced. In the future, transient simulations for loss of flow accident need to be performed to check on the validity of this assumption.

In the whole core model of annular fuel rods, the coolant in the outer channels is free to communicate with adjacent subchannels and exchange heat and mass through the inter-rod gaps. Two key parameters influencing lateral heat and mass exchange between the outer channels considered in the VIPRE-01 code are turbulent mixing coefficient and resistance to lateral flow.

The turbulent mixing model in the energy equation is defined through the turbulent cross flow

$$w' = \beta \, s \, \overline{G} \tag{1}$$

where $\overline{G}$ is the average of the mass velocities in adjacent channels and β is the turbulent mixing coefficient (sometimes designated as thermal diffusion coefficient). Use of a higher turbulent mixing coefficient leads to a decrease in enthalpy and increase in flow rate and DNBR. The gap width for annular fuel is small compared to conventional PWR rod arrays. In bare rods, a smaller gap yields larger turbulent mixing due to lateral turbulence pulsations, which grow with a reduced gap [4]. Annular fuel is expected to use grids with mixing vanes to enhance mixing between outer channels. Weisman et. al. [5] reported β ~ 0.076 for a rod bundle with small mixing vanes. It is expected that the smaller gaps may reduce the effect of mixing enhancement in comparison with the reference fuel with looser P/D. Because no experimental mixing data for this geometry are available and to obtain conservative DNBR results, a zero value for the mixing coefficient β was used in the analyses. This is consistent with an NRC review, which recommends that unless a value of turbulent mixing coefficient can be verified by experimental data, either no turbulent mixing or conservatively small turbulent mixing should be used for licensing calculations [6].

For the cross flow between adjacent channels, the gap width, centroid length and cross flow resistance coefficient K_G, defining the cross flow pressure drop,

$$\Delta p_{cross} = K_G \frac{|w|\, w\, v'}{2s^2}, \tag{2}$$

needs to be supplied. In equation (2), w is the cross flow through the gap in kg/m-s, v' is the specific volume for momentum in kg/m^3 and s the gap width in m. A typical value of the flow resistance coefficient, K_G, between the two rods is on the order of 0.5. This value is usually used in subchannel analyses, since for predominantly axial flows, the crossflow resistance has insignificant effect on the mass flux and DNBR [7]. More exact values can be obtained from a Blasius-type relation. For the cross flow across a tube bundle of a square pitch, an Idelchik [8] diagram can be used to derive A for specified pitch and rod diameter which is used to calculate

$$K_G = A \cdot Re^{-0.2}, \tag{3}$$

where the Reynolds number, Re, is based on the lateral velocity and rod diameter. This relation was used in the VIPRE-01 model.

The turbulent momentum factor, FTM, which determines the degree to which the turbulent crossflow mixes momentum, can be specified on a scale from 0.0 to 1.0, where zero implies that the turbulent cross flow mixes only enthalpy and 1.0 specifies that momentum is mixed to the same extent as enthalpy. An FTM of 0.0 was conservatively chosen for the model.

The details of the VIPRE-01 whole core model of DNBR analysis and assumptions are shown in Table 5.3. MATHCAD files were provided by Westinghouse. Core parameters were calculated in two scenarios as discussed in [2] and in Section 5.1.

Table 5.3 - Summary Table for the VIPRE-01 Model of Annular Fuel Core.

Parameter	**Specification**
Model	Whole core model with lumped sub-channels
Model region	1/8 core, full axial length
Assembly designs	PQN-02 & PQN-03
Guide tube outer diameter	1.5367 cm
Guide tube inner diameter	1.40 cm
Pitch	1.651 cm
Number of sub-channels	49
Number of rods	23
Axial power profile	Chopped cosine, peak-to-average ratio = 1.55
Hot rod power peaking	1.685
Hot assembly power peaking	1.587
Reactor power	18% over power
Power deposited directly in coolant	0.0%
Core mass flow rate	Calculated by MATHCAD files*
Core inlet temperature	increased by 2°C
Cross flow resistance coefficient	$K_G = 7.33\ Re^{-0.2}$
Turbulent mixing model	$\beta = 0.0$
Turbulent momentum factor	$FTM = 0$
Axial friction coefficient for turbulent flow	$f_{ax} = 0.32\ Re^{-0.25}$
Form loss coefficient for mixing vane grids in outer channels	0.6
Inlet and outlet form loss coefficient	0.4 for inlet and 1.0 for outlet

Table 5.3 - Summary Table for the VIPRE-01 Model of Annular Fuel Core (Continuation).

Parameter	Specification
CHF correlations for outer channels	W-3L, mixing factor 0.043, grid spacing factor 0.066, grid factor leading coefficient 0.986
CHF correlation for inner channels	W-3S, mixing factor 0.0
Void correlation	EPRI void model for subcooled void, Zuber-Findlay drift flux equation with coefficients developed for the EPRI void model for bulk void/quality correlation, Columbia/EPRI correlation for two-phase friction multiplier
Heat transfer correlation	Dittus-Boelter for single-phase flow, Thom correlation plus single-phase correlation for subcooled and saturated nuclear boiling

The power distribution in the hot assembly of the 13x13 configuration was calculated earlier by NERI project, and assuming the hot assembly has a power peaking of 1.587 (the same as that for a conventional PWR core), the power distribution in the hot assembly was established as shown in Figure 5.4. In the same manner as for the reference PWR calculations, the hot assembly was moved to the center of the core and surrounded by assemblies with the same power. This will minimize mixing between the outer channels in these assemblies and will yield conservative DNBR results. Powers of the fuel assemblies of the core periphery were adjusted to maintain correct normalization. Figure 5.5 shows the assembly power distribution in the core. A whole core VIPRE-01 model for the 13x13 annular fuel was developed based on the power distribution and numbering schemes according to Figure 5.6 and Figure 5.7. Note that the sub-channels around the hot rod are treated as individual channels while those several pitch lengths away from the hot rod or the hot sub-channel are lumped gradually into larger size channels.

Finally, it is noted that the whole core model had the same nodalization as the whole core model of the reference Westinghouse core with solid fuel, to achieve the largest similarity between the analyses of the annular and reference core. Note that the radial peaking factor for the annular fuel is slightly larger (1.685 versus 1.65) than for the solid core due to larger local peaking within the hot assembly.

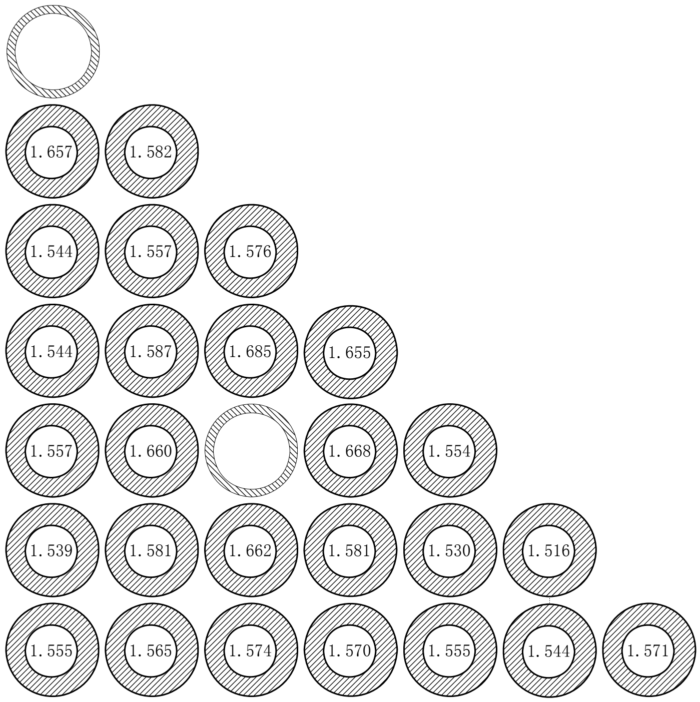

Figure 5.4 - Pin Power Distribution in the Hot Fuel Assembly with 1/8 Symmetry.

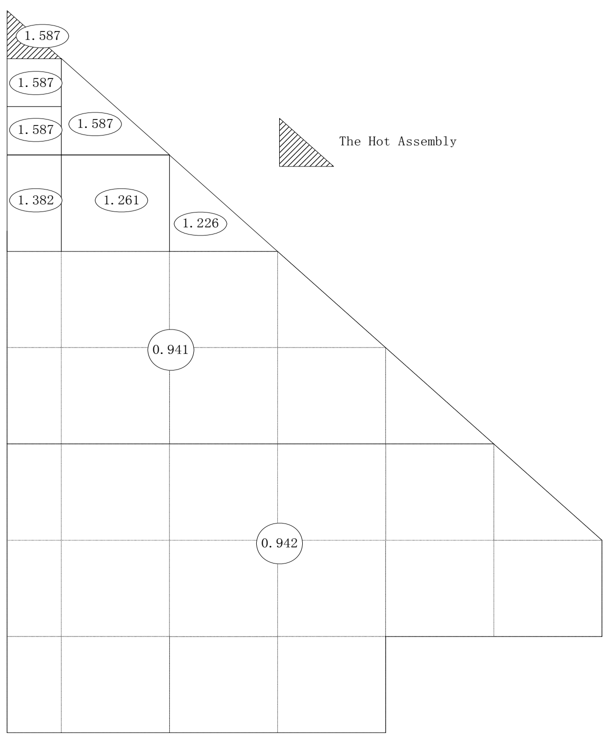

Figure 5.5- Assumed Assembly Power Distribution in the Core.

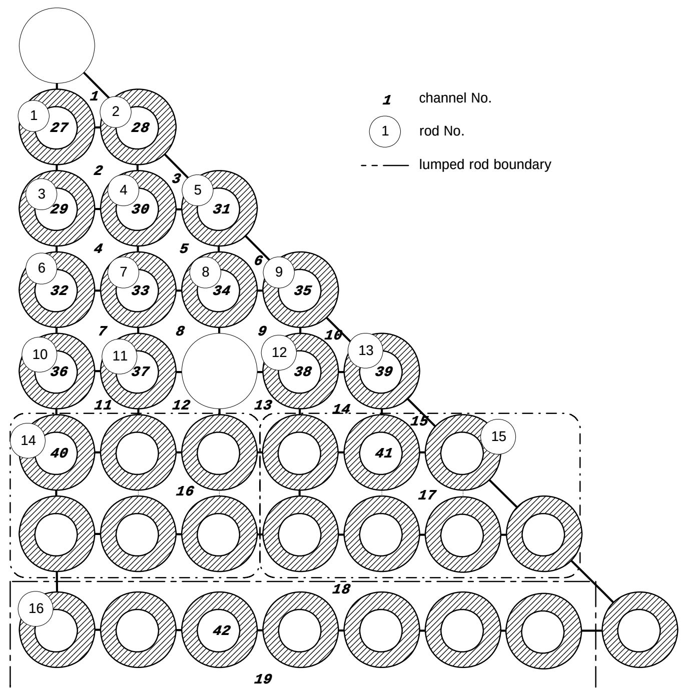

Figure 5.6- Numbering Scheme of Channels and Rods in the Hot Assembly.

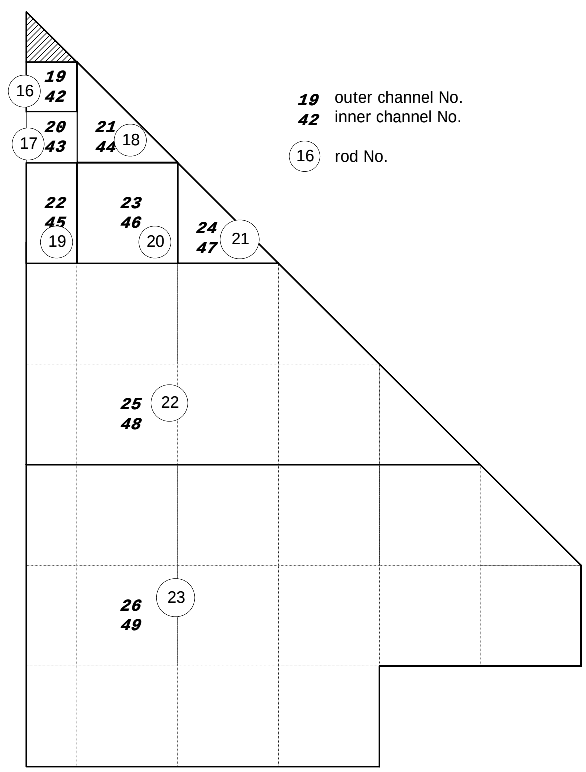

Figure 5.7 - Numbering Scheme of Lumped Channels and Rods in 1/8 Core.

5.2.2 Fuel Designs Analyzed

The 13x13 fuel design, designated PQN-02 was evaluated as a reference case. In addition, a new fuel design, designated as PQN-03, was also analyzed along with PQN-02. The PQN-03 rod design has slightly different inner and outer diameters from those of PQN-02, and it will have a better balance of MDNBR in the inner and outer channels than PQN-02. The dimensions of both PQN-02 and PQN-03 are shown along with reference 17x17 reference solid pin core in Table 5.4 where the first subscripts c and f stand for cladding and fuel, respectively; the second subscripts, i and o designate the inner and outer side diameters of the cladding or fuel ring, and the third subscript denotes the inner or outer cladding (i=inner, o=outer).

Table 5.4 - Comparision of Design Parameters.

Design	D_{cii} (cm)	D_{coi} (cm)	D_{fi} (cm)	D_{fo} (cm)	D_{cio} (cm)	D_{coo} (cm)	Pitch
PQN-02	0.8633	0.9776	0.99	1.41	1.4224	1.5367	1.651
PQN-03	0.861	0.9753	0.9877	1.4225	1.4349	1.5492	1.651
17x17-ref.	Solid pin	NA	NA	0.8255	0.8379	0.9522	1.263

5.2.3 MDNBR Results

In order to find acceptable power uprate and core parameters, a safety analysis limit for MDNBR has to be defined. For Critical Heat Flux (CHF) predicted by the W-3 correlation, a minimum DNBR has to be larger than 1.3 at all times. For this steady-state analysis, conservative conditions (18% overpower and 2°C increased coolant inlet temperature) were applied to calculate MDNBR in an effort to address the spectrum of Condition I and Condition II events. The safety analysis MDNBR limit adopted for judging the acceptability of the new fuel was taken to be the same MDBNR as obtained for the reference W-4 design (Seabrook) using the same DNBR analysis method (18% overpower, 2°C increased coolant inlet temperature, and the same VIPRE-01 modeling assumptions apart from the peculiarities of the annular fuel). Further, to be consistent on flow rate, the core flow rate for the reference solid fuel core was also calculated by the MATHCAD files provided by Westinghouse using the core friction coefficient calculated by VIPRE-01. In the VIPRE-01 whole core model of the reference solid fuel core, the hot pin was assumed to have a power peaking of 1.65 and other detail specifications were similar to those of the annular fuel whole core model as shown in Table 5.3. The calculated MDNBR of the reference solid fuel core was 1.576, as shown in Table 5.5, and this value was used to be the DNBR safety analysis limit for this power uprate analysis. Both calculations use effective core flow rate, i.e., minus core bypass.

Figure 5.8 and Table 5.5 show the DNBR results for various outlet coolant temperatures for Case 1 with RCPs not changed and core power uprate to 125% of current core power. $\dot{M}_{CORE}$, the core mass flow rate, and T_{in}, coolant inlet temperature, were calculated by MATHCAD files provided by Westinghouse given the coolant outlet temperature and core power, and the MDNBR results and core pressure drop by VIPRE-01 whole core model. From Figure 5.8, the coolant inlet temperature limits for this case are around 277 °C and 279 °C for PQN-02 and PQN-03 respectively. At the limit, the coolant inlet temperatures are around 15°C and 13°C lower than that of reference core and the hot leg temperatures (Thot) are around 8°C and 6°C degrees lower than that of the reference core for PQN-02 and PQN-03, respectively (Table 5.5). These temperatures will be used to calculate thermal efficiency and its impact on the economic analysis.

Similarly, Figure 5.9 and Table 5.6 show the results of various outlet coolant temperatures for Case 1 with RCPs not changed, but for the core power uprate to 150%. At the limit, the coolant inlet temperature has to be lowered to around 261.5°C, which is around 30°C lower than the reference case. Such a large temperature reduction does not appear to be promising.

For Case 2, the core power was uprated to 150% of current core power and the RCPs were replaced but their power has to be limited to two times that of current RCP power based on current technology [2]. For the new RCP power range of one to two times the current RCP power, higher RCP power will result in higher coolant temperature for the given MDNBR limit, and, thus, higher thermal efficiency, but larger plant power consumption due to the higher RCP power and vice versa. An optimization process will be necessary to find the best new RCP power for this scenario. In this analysis, the new RCP power was assumed to be equal to the limit of the new RCP power, which is two times that of current RCP power and the results of various outlet coolant temperatures are shown in Figure 5.10 and Table 5.7. From Figure 5.10, the coolant inlet temperature limits for this case are around 279°C and 281°C for PQN-02 and PQN-03, respectively. At the limit, the coolant inlet temperatures are around 13°C and 11°C lower than that of reference core and the hot leg temperatures (Thot) are around 8°C and 6°C degrees lower than that of the reference core for PQN-02 and PQN-03, respectively.

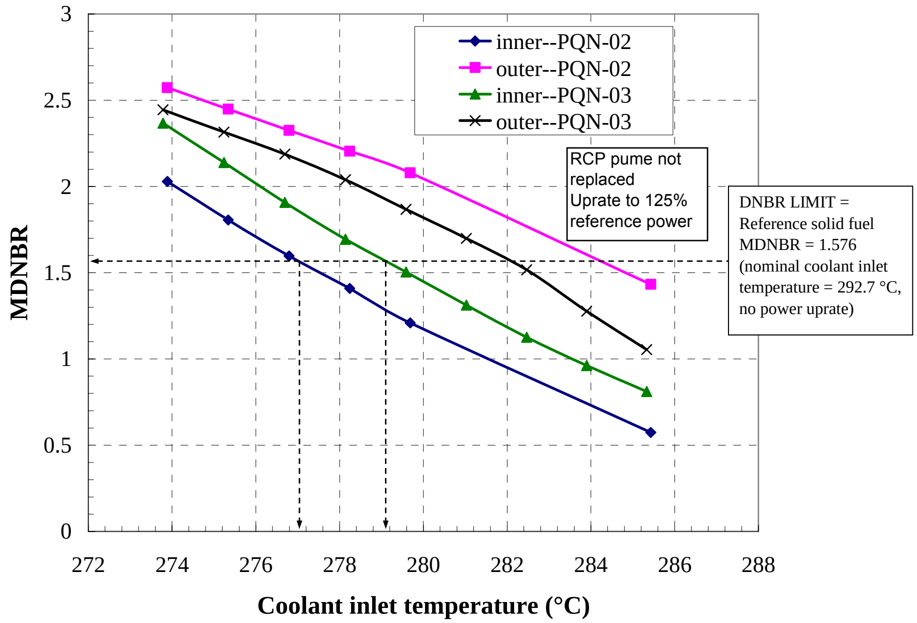

Figure 5.8 - MDNBR Results for Power Uprate to 125% Without RCPs Replacement.

Table 5.5 - Results for Power Uprate to 125% Without RCPs Replacement. Results of Reference Solid Fuel at 100% Current Core Power Also Shown.

Design	T_{in} (°C)	T_{co_out} (°C)	Thot (°C)	$\dot{M}_{CORE}$ (lb/s)	P_{th} (KW)	MDNBR Inner	MDNBR Outer	Pressure Drop (psi)
PQN-02	285.4	326.9	324.0	39623.9	4281250	0.574	1.432	19.21
	279.7	321.4	318.5	40225.7	4281250	1.209	2.079	19.31
	278.2	320.0	317.1	40372.3	4281250	1.409	2.204	19.34
	276.8	318.6	315.7	40517.4	4281250	1.597	2.325	19.37
	275.3	317.2	314.3	40660.9	4281250	1.806	2.448	19.40
	273.9	315.8	312.9	40802.9	4281250	2.029	2.573	19.44
PQN-03	285.3	326.9	324.0	39535.6	4281250	0.811	1.054	19.99
	283.9	325.6	322.6	39687.9	4281250	0.962	1.277	20.02
	282.5	324.2	321.2	39838.8	4281250	1.126	1.517	20.05
	281.0	322.8	319.9	39988.1	4281250	1.312	1.699	20.07
	279.6	321.4	318.5	40135.8	4281250	1.504	1.867	20.10
	278.1	320.0	317.1	40282.1	4281250	1.694	2.039	20.13
	276.7	318.6	315.7	40426.8	4281250	1.908	2.188	20.15
	275.2	317.2	314.3	40569.9	4281250	2.139	2.315	20.19
	273.8	315.8	312.9	40711.4	4281250	2.367	2.444	20.24
Ref. Solid	292.7	326.1	323.8	38974.4	3425000	1.576		18.25

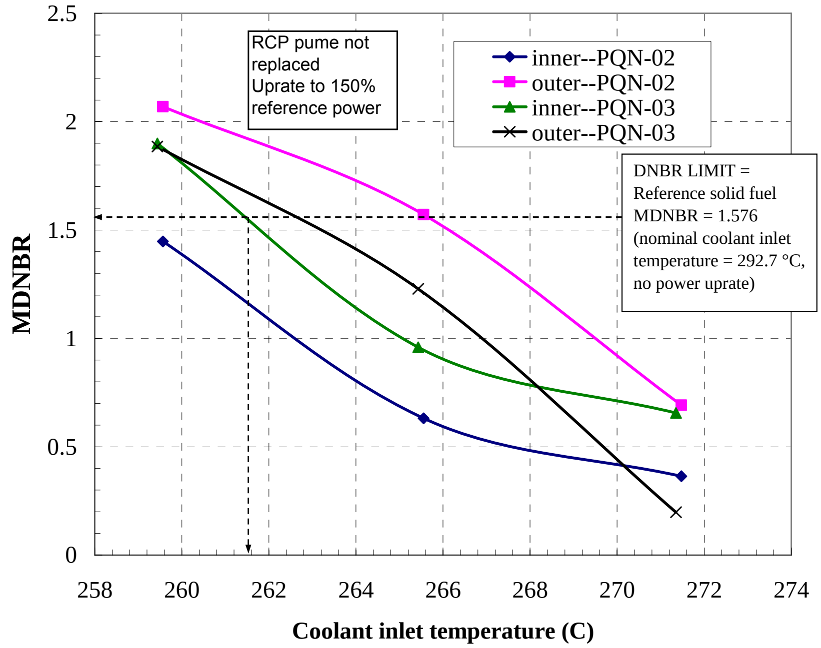

Figure 5.9 - MDNBR Results for Power Uprate to 150% Without RCPs Replacement.

Table 5.6 - Results for Power Uprate to 150% Without RCPs Replacement.

Design	T_{in} (°C)	T_{co_out} (°C)	Thot (°C)	$\dot{M}_{CORE}$ (lb/s)	P_{th} (KW)	MDNBR		Pressure Drop (psi)
						Inner	Outer	
PQN-02	271.5	321.4	317.9	40918.4	5137500	0.364	0.692	19.98
	265.6	315.8	312.3	41467.5	5137500	0.631	1.571	20.06
	259.6	310.3	306.7	41990.7	5137500	1.447	2.069	20.14
PQN-03	271.4	321.4	317.9	40827.4	5137500	0.656	0.198	20.80
	265.4	315.8	312.3	41374.9	5137500	0.959	1.229	20.87
	259.4	310.3	306.7	41896.6	5137500	1.899	1.885	20.98

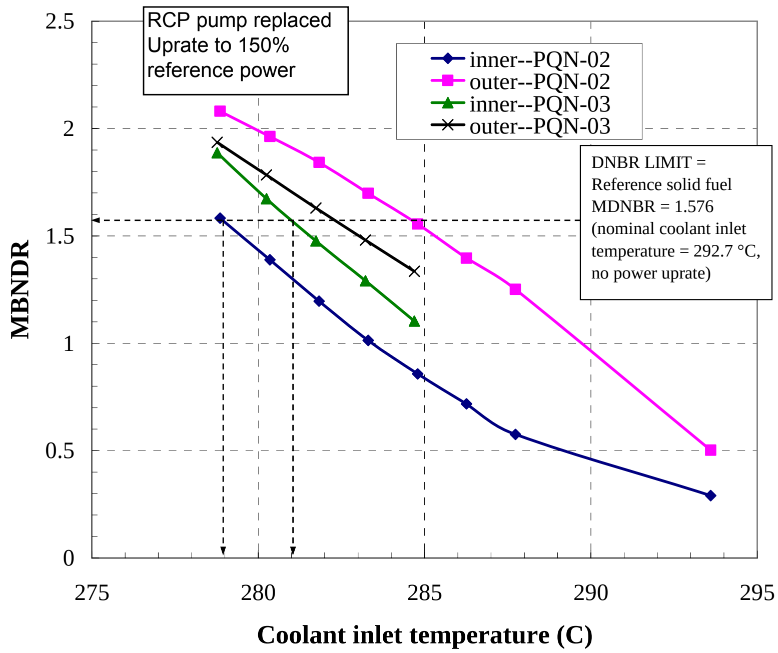

Figure 5.10 - MDNBR Results for Power Uprate to 150% With RCPs Replaced and Power Doubled.

Table 5.7 - Results for Power Uprate to 150% With RCPs Replaced and Pump Power Doubled.

Design	T_{in} (°C)	T_{co_out} (°C)	Thot (°C)	$\dot{M}_{CORE}$ (lb/s)	P_{th} (KW)	MDNBR		Pressure Drop (psi)
						Inner	Outer	
PQN-02	293.6	332.5	329.8	49575	5137500	0.291	0.502	27.72
	287.7	326.9	324.2	50142.8	5137500	0.576	1.251	27.63
	286.3	325.6	322.8	50282.7	5137500	0.718	1.396	27.61
	284.8	324.2	321.4	50430.9	5137500	0.857	1.555	27.60
	283.3	322.8	320.0	50554.6	5137500	1.013	1.698	27.58
	281.8	321.4	318.6	50693.3	5137500	1.196	1.842	27.57
	280.4	320.0	317.2	50840.6	5137500	1.389	1.963	27.58
	278.9	318.6	315.8	50956.7	5137500	1.582	2.08	27.56
PQN-03	284.7	324.2	321.4	50311.9	5137500	1.103	1.335	28.79
	283.2	322.8	320.0	50455.3	5137500	1.291	1.48	28.78
	281.7	321.4	318.6	50580.9	5137500	1.476	1.63	28.76
	280.3	320.0	317.2	50715	5137500	1.673	1.784	28.75
	278.8	318.6	315.8	50851	5137500	1.887	1.936	28.75

5.2.4 References

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6 Steam Generators (M. H. Hu, P. Rubiolo, WEC)

The Westinghouse Delta 75 steam generator (SG) design was selected for feasibility assessment in the ultra uprate concept. The Delta 75 steam generator has a heat transfer area of 75,200 square feet of tube bundle with a triangular layout. There are 6,307 tubes with 0.688 inch outside diameter. Such a design is used to replace the original steam generator with a heat transfer area of 48,000 square feet. Therefore, the Delta 75 SG has a 57% increase in heat transfer area and yet operates at the same thermal power level as the original steam generator. This underutilization makes it feasible to accommodate the 50% more heat transfer area within the space constraint of the containment building. Two uprated power levels (125% and 150% of the 3,425 MWt for a four loop plant) are considered with feed water temperatures of 440^{o}F and 420^{o}F.

The fundamental requirements of a steam generator and the potential issues when operated at uprated powers will be discussed. Some issues can be resolved by further detailed analysis while others may need modifications to the existing design features. The latter issues are considered “bottlenecks”. Resolution of the bottlenecks is outlined with the estimated cost to do so.

The following analysts are responsible for the various parts included in this section:

M. H. Hu	Overall section and Section 6.1 (Steam Pressure and Steam Flow Performance at Various Feedwater Temperatures)
	Section 6.2 (Circulation Ratio and Total Flow Through the Tube Bundle)
	Section 6.3 (Assessment of Operational Issues)
	Section 6.4 (Bottlenecks and Resolution)
Pablo Rubiolo	Section 6.5 (Integration of Steam Generator, Fuel and Reactor Coolant Pump Design)

6.1 Steam Pressure and Steam Flow Performance at Various Feedwater Temperatures

The fundamental function of the SG is to deliver the thermal power at the specified steam pressure. Table 6.1 through Table 6.4 tabulate the steam pressure and steam flow of the steam generator calculated at feed water temperatures of 440^{o}F and 420^{o}F by the GENF computer program for Ultra-Uprates (UUs) of 125% and 150%, respectively. Both steam pressure and steam flow can be used to assess the feasibility for steam flow to pass through the turbine valve at the wide open position.

Table 6.1 uses a feed water temperature of 440^{o}F and Table 6.2 uses 420^{o}F for the 125% power cases with the reference solid fuel at 100% power. As expected, a lower feed water temperature results in a lower steam flow because a relatively larger amount of reactor coolant energy has to be used to preheat more subcooled water. According to GENF calculations, the effect of preheating for a feed ring type of steam generator is insignificant, as expected, in raising steam pressure and temperature. Similar observation holds true for Table 6.3 for 440^{o}F feedwater and Table 6.4 for 420^{o}F feedwater for the 150% power cases.

Table 6.1 - Steam Pressure and Steam Flow at 125% Power[1]
With Feed Water Temperature at 440°F.

Design	Tcold, °F	Thot, °F	Wrcs per SG, lb_m/hr	Steam Pressure, Psia	Steam Temp, °F	Steam Flow per SG, Million lb_m/hr	Tube Bundle Flow, Million lb_m/hr	Steam Enthalpy, Btu/lb_m
PQN-02	545.58	616.18	3.8297E+07	914.78	533.89	4.7072	0.90	1195.91
	535.32	606.87	3.8873E+07	834.61	523.11	4.6920	0.89	1198.41
	532.72	604.48	3.9015E+07	815.77	520.46	4.6886	0.89	1198.95
	530.11	602.07	3.9155E+07	796.59	517.72	4.6853	0.88	1199.48
	527.50	599.66	3.9294E+07	777.70	514.97	4.6822	0.88	1199.98
	524.78	597.13	3.9436E+07	758.35	512.09	4.6792	0.88	1200.48
PQN-03	545.38	616.16	3.8212E+07	913.34	533.70	4.7069	0.90	1195.96
	543.01	614.02	3.8348E+07	894.55	531.24	4.7032	0.90	1196.57
	540.43	611.69	3.8494E+07	874.38	528.55	4.6992	0.90	1197.21
	537.73	609.23	3.8644E+07	853.61	525.73	4.6953	0.89	1197.84
	535.14	606.86	3.8786E+07	833.98	523.02	4.6918	0.89	1198.43
	532.54	604.48	3.8928E+07	813.25	520.10	4.6881	0.89	1199.02
	529.93	602.07	3.9067E+07	795.43	517.55	4.6851	0.88	1199.51
	527.32	599.65	3.9206E+07	776.56	514.80	4.6820	0.88	1200.01
	524.59	597.11	3.9348E+07	757.16	511.92	4.6790	0.88	1200.51
RSF	558.19	613.81	3.8431E+07	1036.26	548.92	3.7872	1.00	1191.58

[1] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

Table 6.2 - Steam Pressure and Steam Flow at 125% Power[2] With Feed Water Temperature at 420°F.

Design	Tcold, °F	Thot, °F	Wrcs per SG, lb_m/hr	Steam Pressure, Psia	Steam Temp, °F	Steam Flow per SG, Million lb_m/hr	Tube Bundle Flow, Million lb_m/hr	Steam Enthalpy, Btu/lb_m
PQN-02	545.58	616.18	3.8297E+07	915.25	533.95	4.5780	0.91	1195.89
	535.32	606.87	3.8873E+07	835.69	523.26	4.5634	0.90	1198.38
	532.72	604.48	3.9015E+07	816.28	520.53	4.5602	0.90	1198.93
	530.11	602.07	3.9155E+07	797.12	517.79	4.5571	0.90	1199.47
	527.50	599.66	3.9294E+07	778.25	515.05	4.5541	0.89	1199.97
	524.78	597.13	3.9436E+07	758.91	512.18	4.5512	0.89	1200.47
PQN-03	545.38	616.16	3.8212E+07	913.81	533.76	4.5777	0.91	1195.94
	543.01	614.02	3.8348E+07	895.02	531.30	4.5741	0.91	1196.55
	540.43	611.69	3.8494E+07	874.87	528.61	4.5704	0.90	1197.19
	537.73	609.23	3.8644E+07	854.10	525.80	4.5666	0.90	1197.83
	535.14	606.86	3.8786E+07	834.49	523.09	4.5632	0.90	1198.41
	532.54	604.48	3.8928E+07	815.10	520.37	4.5600	0.90	1198.97
	529.93	602.07	3.9067E+07	795.97	517.63	4.5569	0.90	1199.50
	527.32	599.65	3.9206E+07	777.12	514.88	4.5539	0.89	1200.00
	524.59	597.11	3.9348E+07	757.72	512.00	4.5510	0.89	1200.50
RSF	558.19	613.81	3.8431E+07	1036.50	548.95	3.6828	1.00	1191.57

[2] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

Table 6.3 - Steam Pressure and Steam Flow at 150% Power[3] With Feed Water Temperature at 440°F.

Design	Tcold, °F	Thot, °F	Wrcs, lb_m/hr	Steam Pressure, Psia	Steam Temp, °F	Steam Flow per SG, Million lb_m/hr	Tube Bundle Flow, Million lb_m/hr	Steam Enthalpy, Btu/lb_m
PQN-02	560.50	625.62	4.7868E+07	1001.11	544.72	5.6711	0.79	1192.90
	549.90	615.49	4.9262E+07	912.09	533.54	5.6480	0.78	1196.00
	547.30	613.17	4.9428E+07	891.30	530.81	5.6431	0.78	1196.67
	544.60	610.66	4.9673E+07	869.92	527.95	5.6381	0.77	1197.35
	541.90	608.05	4.9984E+07	848.77	525.07	5.6334	0.76	1197.99
	539.20	605.54	5.0204E+07	828.08	522.20	5.6289	0.76	1198.60
	536.70	603.04	5.0542E+07	809.01	519.50	5.6249	0.75	1199.14
	534.00	600.53	5.0739E+07	788.97	516.61	5.6209	0.75	1199.69
PQN-03	544.50	610.65	4.9610E+07	869.24	527.86	5.6379	0.77	1197.37
	541.80	608.05	4.9920E+07	848.10	524.97	5.6332	0.76	1198.01
	539.10	605.53	5.0140E+07	827.42	522.10	5.6287	0.76	1198.62
	536.50	603.03	5.0412E+07	807.72	519.32	5.6247	0.75	1199.17
	533.80	600.51	5.0610E+07	787.71	516.43	5.6206	0.75	1199.72

[3] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

Table 6.4 - Steam Pressure and Steam Flow at 150% Power[4]
With Feed Water Temperature at 420°F.

Design	Tcold, °F	Thot, °F	Wrcs, lb_m/hr	Steam Pressure, Psia	Steam Temp, °F	Steam Flow per SG, Million lb_m/hr	Tube Bundle Flow, Million lb_m/hr	Steam Enthalpy, Btu/lb_m
PQN-02	560.50	625.62	4.7868E+07	1001.72	544.79	5.5149	0.80	1192.87
	549.90	615.49	4.9262E+07	912.77	533.62	5.4930	0.80	1195.98
	547.30	613.17	4.9428E+07	892.00	530.90	5.4883	0.79	1196.65
	544.60	610.66	4.9673E+07	870.64	528.05	5.4835	0.78	1197.32
	541.90	608.05	4.9984E+07	849.50	525.17	5.4790	0.78	1197.97
	539.20	605.54	5.0204E+07	828.83	522.30	5.4747	0.78	1198.58
	536.70	603.04	5.0542E+07	809.78	519.61	5.4709	0.77	1199.12
	534.00	600.53	5.0739E+07	789.76	516.73	5.4671	0.77	1199.66
PQN-03	544.50	610.65	4.9610E+07	869.96	527.95	5.4834	0.78	1197.34
	541.80	608.05	4.9920E+07	848.84	525.08	5.4789	0.78	1197.99
	539.10	605.53	5.0140E+07	828.18	522.21	5.4746	0.78	1198.59
	536.50	603.03	5.0412E+07	808.50	519.43	5.4707	0.77	1199.15
	533.80	600.51	5.0610E+07	788.50	516.55	5.4669	0.77	1199.70

[4] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

6.2 Circulation Ratio and Total Flow Through the Tube Bundle

In addition to steam pressure and steam flow rate, the GENF code also calculates other parameters, such as circulation ratio and total flow through the tube bundle, that are tabulated in Table 6.5, Table 6.6, Table 6.7 and Table 6.8 for 125% and 150% power, respectively. The circulation ratio is defined as a ratio of the total flow through the tube bundle to the steam flow. As shown, the circulation ratio decreases with an increase in power. Note that the inverse of circulation ratio indicates a value of steam quality leaving the tube bundle.

Secondary side water and steam mass for both 125% and 150% power levels is less than that for the reference design (reference solid fuel (RSF) at 100% power), and, thus, the potential mass release to the containment building due to either steam line break or feed water line break should be bounded by the current full power conditions. Again, the secondary side fluid heat is bounded by the RSF design that would have a secondary fluid heat of 64 million BTU.

Thermal cycle efficiency is directly proportional to steam pressure. The reference solid fuel design, as expected, has the highest thermal cycle efficiency (38.83%). All uprate designs have thermal cycle efficiency less than 38.83% (up to 1% less). Of course, it is desirable to have higher thermal cycle efficiency, because even just 1% less in efficiency would amount to 40 to 50 MWt. However, this would not be the key concern in the uprate design. The key concern is the limit of steam pressure and steam flow rate through the turbine valve in the wide open (VWO) position. Prior to the turbine valve in the VWO position, a drop of 10 psi translates to a loss of about half million dollars in electric revenue, and, afterward, a VWO a drop of 10 psi amounts to a loss of 10 million dollars in electric revenue.

Table 6.5 - T/H Characteristics of Steam Generator[5] at 125% Power With Feed Water Temperature of 440^{o}F.

Design	Circu-lation Ratio	Hydro-dynamic Damping Factor, 1/hr	Secondary Side Water and Steam Mass, lb_m	Secondary Side Fluid Heat, Million Btu	Separator Parameter, 10^{12} lbm-ft3/hr2	Primary Pressure Drop, psi	Tube Bundle Flow, Million lb_m/hr	Thermal Cycle Efficiency, %
PQN-02	2.79	-459	105025	58.183	10.88	37.17	8.4259	38.38
	2.78	-483	103006	55.784	11.94	37.72	8.3518	38.06
	2.78	-490	102507	55.193	12.22	37.86	8.3457	37.97
	2.77	-497	102004	54.603	12.52	37.99	8.2930	37.88
	2.77	-505	101495	54.015	12.83	38.12	8.2875	37.79
	2.77	-514	100958	53.403	13.16	38.26	8.2822	37.70
PQN-03	2.79	-460	104988	58.139	10.90	37.01	8.4254	38.38
	2.79	-465	104507	57.573	11.13	37.14	8.4187	38.30
	2.79	-470	103997	56.966	11.39	37.28	8.4116	38.22
	2.78	-477	103473	56.341	11.67	37.42	8.3576	38.13
	2.78	-483	102975	55.748	11.95	37.56	8.3514	38.05
	2.78	-490	102476	55.157	12.24	37.70	8.3448	37.96
	2.77	-498	101973	54.567	12.54	37.83	8.2926	37.88
	2.77	-506	101454	53.979	12.85	37.96	8.2871	37.79
	2.77	-515	100924	53.366	13.18	38.10	8.2818	37.70
RSF	3.48	-432	112168	64.414	6.13	37.64	9.3923	38.83

[5] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

Table 6.6 - T/H Characteristics of Steam Generator[6] at 125% Power With Feed Water Temperature of 420°F.

Design	Circu-lation Ratio	Hydro-dynamic Damping Factor, 1/hr	Secondary Side Water and Steam Mass, lb_m	Secondary Side Fluid Heat, Million Btu	Separator Parameter, 10^{12} lbm-ft3/hr2	Primary Pressure Drop, psi	Tube Bundle Flow, Million lb_m/hr	Thermal Cycle Efficiency, %
PQN-02	2.88	-428	107210	58.832	10.29	37.17	8.6066	38.38
	2.87	-444	105261	56.441	11.28	37.72	8.5336	38.06
	2.86	-449	104780	55.851	11.56	37.86	8.4820	37.97
	2.86	-454	104294	55.263	11.84	37.99	8.4762	37.88
	2.86	-460	103804	54.676	12.13	38.12	8.4706	37.79
	2.85	-466	103284	54.065	12.44	38.26	8.4197	37.70
PQN-03	2.88	-428	107175	58.789	10.30	37.01	8.6061	38.38
	2.88	-431	106711	58.224	10.52	37.14	8.5993	38.30
	2.87	-435	106218	57.620	10.77	37.28	8.5466	38.22
	2.87	-440	105712	56.996	11.04	37.42	8.5395	38.13
	2.87	-444	105232	56.404	11.30	37.56	8.5332	38.05
	2.86	-449	104750	55.815	11.57	37.70	8.4816	37.96
	2.86	-454	104265	55.227	11.86	37.83	8.4758	37.88
	2.86	-460	103773	54.640	12.15	37.96	8.4703	37.79
	2.85	-466	103252	54.027	12.46	38.10	8.4194	37.70
RSF	3.57	-408	114086	65.047	5.80	37.64	9.4648	38.83

[6] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

Table 6.7 - T/H Characteristics of Steam Generator[7] at 150% Power With Feed Water Temperature of 440^{o}F.

Design	Circu-lation Ratio	Hydro-dynamic Damping Factor, 1/hr	Secondary Side Water and Steam Mass, lb_m	Secondary Side Fluid Heat, Million Btu	Separator Parameter, 10^{12} lbm-ft3/hr2	Primary Pressure Drop, psi	Tube Bundle Flow, Million lb_m/hr	Thermal Cycle Efficiency, %
PQN-02	2.31	-429	104403	58.780	14.30	57.39	7.4291	38.69
	2.29	-446	101871	56.073	15.72	59.60	7.2859	38.37
	2.29	-451	101304	55.450	16.09	59.77	7.2796	38.29
	2.28	-456	100725	54.811	16.49	60.10	7.2168	38.21
	2.27	-462	100154	54.179	16.91	60.59	7.1544	38.12
	2.26	-468	99593	53.559	17.34	60.88	7.0924	38.03
	2.26	-474	99068	52.985	17.75	61.44	7.0874	37.94
	2.25	-481	98506	52.375	18.21	61.69	7.0261	37.85
PQN-03	2.28	-456	100707	54.791	16.50	59.96	7.2165	38.20
	2.27	-462	100136	54.159	16.92	60.44	7.1542	38.11
	2.26	-468	99575	53.540	17.35	60.73	7.0922	38.02
	2.26	-474	99032	52.946	17.78	61.14	7.0871	37.94
	2.25	-481	98470	52.337	18.24	61.39	7.0258	37.85

[7] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

Table 6.8 - T/H Characteristics of Steam Generator[8] at 150% Power With Feed Water Temperature of 420^{o}F.

Design	Circu-lation Ratio	Hydro-dynamic Damping Factor, 1/hr	Secondary Side Water and Steam Mass, lb_m	Secondary Side Fluid Heat, Million Btu	Separator Parameter, 10^{12} lbm-ft3/hr2	Primary Pressure Drop, psi	Tube Bundle Flow, Million lb_m/hr	Thermal Cycle Efficiency, %
PQN-02	2.38	-402	106659	59.399	13.51	57.39	7.6106	38.69
	2.37	-413	104203	56.698	14.85	59.60	7.5254	38.37
	2.36	-416	103654	56.076	15.20	59.77	7.4641	38.29
	2.35	-419	103096	55.438	15.58	60.10	7.4027	38.21
	2.35	-422	102544	54.807	15.98	60.59	7.3967	38.12
	2.34	-426	102002	54.188	16.38	60.88	7.3361	38.03
	2.33	-430	101495	53.613	16.78	61.44	7.2763	37.94
	2.33	-434	100953	53.004	17.21	61.69	7.2712	37.85
PQN-03	2.35	-419	103078	55.418	15.60	59.96	7.4026	38.20
	2.35	-422	102527	54.787	16.00	60.44	7.3965	38.11
	2.34	-426	101984	54.168	16.40	60.73	7.3360	38.02
	2.33	-430	101461	53.574	16.80	61.14	7.2760	37.94
	2.33	-435	100918	52.965	17.24	61.39	7.2710	37.85

[8] Only the cases shown in shadow satisfy DNBR criterion and thus are acceptable.

6.3 Assessment of Operational Issues

The size of the Delta 75 steam generator is adequate to deliver the needed steam flow at the specified steam pressure at either 125% or 150% power. However, there are potential operational issues at such uprated power levels. These issues include:

1. Tubing corrosion
2. Hydrodynamic instability
3. Erosion-corrosion of the feedwater distribution system
4. Flow induced tube vibration
5. Excessive moisture carryover.

6.3.1 Tubing Corrosion

The key parameter that can significantly affect tubing corrosion is the reactor coolant temperature entering the steam generator (Thot). Using the reference solid fuel (RSF) as baseline (see Table 6.5 and Table 6.6), the baseline Thot is about 614 ^{o}F. All of the proposed uprated cases that satisfy DNBR safety analysis limit have its Thot less than 614 oF, thus smaller than normal corrosion rates are expected.

Another contributor to tubing corrosion is excessive tube deposition. Local dryout of a tube can lead to excessive deposition of corrosion products (particulate, colloid or solute) entering the steam generator. For a 150% power level, the circulation ratio is around 2.3, and a circulation ratio of 2.3 is comparable to those in some current steam generators. Therefore, operation of steam generators at such a circulation ratio may not present problems, such as local tube dryout, excessive tube deposition, and tubing corrosion. Note that local tube deposition increases with an increase in steam quality and a lower circulation ratio means a higher steam quality at some localities. There are some reports of excessive tube deposits that have actually bridged from tube to neighboring tubes and caused tube damage. Therefore, the impact of low circulation ratio needs a closer look. A detailed, three dimensional thermal and flow analysis is required to evaluate the potential for local dryout.

6.3.2 Hydrodynamic Instability

Hydrodynamic instability is a potential problem in any fluid system where boiling takes place. Instability, if present in the PWR steam generator, will result in periodic oscillations in water level, steam flow, feed water flow and flow through the circulation loop. Density wave instability is the most common type encountered in the boiling heat exchanger. The density wave instability results from an unfavorable distribution of pressure drop through the circulation loop. The GENF code has incorporated a linearized stability model. The model provides both an oscillation damping factor and period. A positive damping factor implies that the any oscillation in flow would diverge exponentially, while a negative one would die out exponentially.

Hydrodynamic damping factors have a big negative value for all designs with both 125% and 150% power levels, as tabulated in Table 6.5 through Table 6.8. Therefore, stable operation without water level oscillations is expected.

6.3.3 Erosion-Corrosion of Feed Water Distribution System

Erosion-corrosion has been observed in the existing feed water distribution hardware made of carbon steel without trace chrome. Power uprating will increase feed water velocity up to 50% more and, thus, the potential of erosion-corrosion definitely increases. However, it is manageable by using steel with a trace of chrome content.

6.3.4 Flow Induced Tube Vibration and Wear

Table 6.1 through Table 6.4 tabulate tube bundle flow and the ratio of tube bundle flow at uprating powers to that at the original 100% power (i.e., the RSF design). As can be seen, the tube bundle flow ratio is around 0.9 and 0.8 for the 125% and 150% uprate powers, respectively. The reason that total tube bundle flow decreases is that, at either 125% or 150% power, pressure drop increases faster than the hydrostatic head difference between the downcomer and the tube bundle. The faster increase in the pressure drop is due to higher void fraction in the tube bundle at 125% or 150% power when compared to the 100% power.

The RSF design has the highest value (9.4 million lbm/hr), and all uprate designs have a value less than 9.4 million lbm/hr. Therefore, fluid energy input to the tube would be less for the uprate design, and, thus, there is less potential for fluid induced tube vibration. However, the damping coefficient will also be less in the U-bend area for the uprate designs and this is not desirable. The combined impact of velocity and damping coefficient may still be high enough to preclude fluid induced tube vibration. Note that there is flow induced tube vibration for the current 100% power, as demonstrated in actual plant operation.

A careful evaluation should be done to evaluate the effect of the damping coefficient in the U-bend. Both the 125% and 150% uprate power leads to a lower steam pressure than that at the 100% power and, thus, the damping coefficient will be smaller for the 125% or 150% power and its impact on tube vibration has to be evaluated. If tube vibration would become a concern, a modification to the current design of tube support plates and anti-vibration bars should eliminate the vibration.

6.3.5 Excessive Moisture Carryover

Excessive moisture carryover could take place when the power is uprated beyond the rated 100% power. The reason is that steam flow is increased as much as the amount of power uprating, and, thus, the separator equipment is overloaded just by the amount of steam flow alone. In addition, steam pressure for the 125% or 150% power is much lower than that for the 100% power. The lower the steam pressure, the less efficient is the separator equipment in separating the moisture. The GENF code calculates a factor called the "separator parameter" that is defined as steam flow squared times steam specific volume. Thus, the separator parameter takes both steam flow loading and steam pressure into consideration.

Table 6.5, Table 6.6, Table 6.7 and Table 6.8 tabulate the separator parameter. The reference solid fuel design at 100% power has a separator parameter of 6.13×10^{12} $lb_m\text{-}ft^3/hr^2$. All designs at either 125% or 150% power level have a separator parameter almost 2 times or 3 times that of 100% power design. According to the operating experience, a separator parameter that is 2 or 3 times that of the 100% power case is definitely too high to avoid excessive moisture carryover (i.e., more than the design limit of 0.25% of the steam flow).

Therefore, the current moisture separation equipment is definitely a bottleneck. Solutions include a design modification and tests to verify the design. Development of a design modification and verification tests would cost about one half to one million dollars.

6.4 Bottlenecks and Resolution

Table 6.9 summarizes the potential bottlenecks and their solutions based on the above assessments. A cost estimate to resolve each of the bottlenecks is also provided.

Table 6.9 – Steam Generator Uprate Bottlenecks, Resolution and Costs.

Bottleneck	Resolution	Cost ($K)	Probability of Solution
Erosion-corrosion of feed water flow system	3-D velocity analysis and evaluate the need to have chrome content in steel	30	High
Local dryout in tube bundle	DNB evaluation via 3-D T/H analysis	30	High
Flow induced tube vibration	Tube vibration & wear evaluation; modify tube support, if needed	30 to 80	High
Excessive moisture carryover	Modify the moisture separators and verify with model tests at proto-typical conditions	500 to 1000	High

6.5 Integration of Steam Generator, Fuel and Reactor Coolant Pump Design

Based on the design conditions outlined in Sections 5.1 and 5.2, an integrated thermal hydraulic analysis with and without the replacement of the RCP at feedwater temperatures of 440°F was made. These results are presented in Table 6.10 and Table 6.11 for the 125% and 150% uprates, respectively. These calculations indicate a relatively wide range of potential operating conditions.

Table 6.10- Steam Pressure and Steam Flow at 125% Power (Without RCPs Replaced) With Feed Water Temperature At 440°F (Shaded areas indicate acceptable operating points).

Design**	Tcold, °F	Thot, °F	MDNBR Inner Channel	MDNBR Outer Channel	Wrcs per SG, lb_m/hr	Steam Pressure, Psia	Steam Temperature, °F	Steam Flow per SG, Million lb_m/hr
PQN-02	545.58	616.18	0.574	1.432	3.8297E+07	914.78	533.89	4.7072
	535.32	606.87	1.209	2.079	3.8873E+07	834.61	523.11	4.6920
	532.72	604.48	1.409	2.204	3.9015E+07	815.77	520.46	4.6886
	530.11	602.07	1.597	2.325	3.9155E+07	796.59	517.72	4.6853
	527.50	599.66	1.806	2.448	3.9294E+07	777.70	514.97	4.6822
	524.78	597.13	2.029	2.573	3.9436E+07	758.35	512.09	4.6792
PQN-03	545.38	616.16	0.811	1.054	3.8212E+07	913.34	533.70	4.7069
	543.01	614.02	0.962	1.277	3.8348E+07	894.55	531.24	4.7032
	540.43	611.69	1.126	1.517	3.8494E+07	874.38	528.55	4.6992
	537.73	609.23	1.312	1.699	3.8644E+07	853.61	525.73	4.6953
	535.14	606.86	1.504	1.867	3.8786E+07	833.98	523.02	4.6918
	532.54	604.48	1.694	2.039	3.8928E+07	813.25	520.10	4.6881
	529.93	602.07	1.908	2.188	3.9067E+07	795.43	517.55	4.6851
	527.32	599.65	2.139	2.315	3.9206E+07	776.56	514.80	4.6820
	524.59	597.11	2.367	2.444	3.9348E+07	757.16	511.92	4.6790
RSF*	558.19	613.81	1.576		3.8431E+07	1036.26	548.92	3.7872

Table 6.11 - Steam Pressure and Steam Flow at 150% Power (With RCPs Replaced) With Feed Water Temperature At 440°F (Shaded areas indicate acceptable operating points).

Design**	Tcold, °F	Thot, °F	MDNBR Inner Channel	MDNBR Outer Channel	Wrcs, lb_m/hr	Steam Pressure, Psia	Steam Temperature, °F	Steam Flow per SG, Million lb_m/hr
PQN-02	560.50	625.62	0.291	0.502	4.7868E+07	1001.11	544.72	5.6711
	549.90	615.49	0.576	1.251	4.9262E+07	912.09	533.54	5.6480
	547.30	613.17	0.718	1.396	4.9428E+07	891.30	530.81	5.6431
	544.60	610.66	0.857	1.555	4.9673E+07	869.92	527.95	5.6381
	541.90	608.05	1.013	1.698	4.9984E+07	848.77	525.07	5.6334
	539.20	605.54	1.196	1.842	5.0204E+07	828.08	522.20	5.6289
	536.70	603.04	1.389	1.963	5.0542E+07	809.01	519.50	5.6249
	534.00	600.53	1.582	2.08	5.0739E+07	788.97	516.61	5.6209
PQN-03	544.50	610.65	1.103	1.335	4.9610E+07	869.24	527.86	5.6379
	541.80	608.05	1.291	1.48	4.9920E+07	848.10	524.97	5.6332
	539.10	605.53	1.476	1.63	5.0140E+07	827.42	522.10	5.6287
	536.50	603.03	1.673	1.784	5.0412E+07	807.72	519.32	5.6247
	533.80	600.51	1.887	1.936	5.0610E+07	787.71	516.43	5.6206

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7 Safety Assessment of the Uprate (L. Oriani, J. Hartz, U. Bachrach and L. Smith, WEC)

7.1 Introduction

The objective of this section is to document a preliminary safety assessment for very large power uprates (of up to 50%) on existing Westinghouse PWRs. This evaluation is part of a joint Westinghouse-EPRI Innovation program.

Given the limited funding available, only qualitative considerations are provided in this section, with particular emphasis on the plant modifications/replacements of existing reactor coolant system components (steam generators, reactor coolant pumps) of auxiliary systems and of the balance of plant that could be required to achieve such large uprates. As such, extensive plant changes are expected to be necessary, including major overhauls on the balance of plant.

Section 8 addresses the required plant modifications/replacements. The focus of this section is to identify plant changes and potential key issues that would need to be addressed to achieve a large uprate.

Section 7.2 provides a summary of the main conclusions of this study and focuses on the necessary plant modifications. To perform this evaluation, several key assumptions were made. The assumptions are consistent with the overall basis of the project and are listed and discussed in Section 7.3.

The following analysts are responsible for the various parts included in this section:

Luca Oriani	Non-LOCA events and Large Break LOCA
Josh Hartz	Small Break LOCA
Uriel Bachrach	Dose Evaluations and Steam Generator Tube Rupture
Larry Smith	Containment Analysis

7.2 Summary of Results and Conclusions

Based on the results of the assessment and under the assumptions listed in Section 7.3 (see also [1], [2], [3] and [4]), no show stoppers for the APUU (Advanced Power Ultra Uprate) program have been identified from the point of view of safety considerations. This conclusion can only be considered preliminary given the limited scope of this assessment, and is conditional on a set of plant modifications that would need to be completed to allow the uprate. In addition, the use of more advanced and less conservative evaluation models for safety analyses has been identified as a requirement for several of the considered analyses. While, in most cases, these advanced evaluation models have either been already licensed or are in the process of being licensed, the costs connected with applying more advanced and complex methodologies should not be underestimated.

From the point of view of plant systems and the need for component replacements, the following key items were identified:

1. To satisfy the acceptance criteria for reactor coolant system (RCS) overpressure events (i.e., Turbine Trip, Load Rejection, …), the Pressurizer should be replaced and provided with an increased steam space to absorb the initial high pressurization rate. As a rough estimate, the replacement pressurizer increase in size should be of the order of the power increase. Also, it would be appropriate to increase the capacity of the safety relief valves in the replacement pressurizer to increase the steam release rate, especially for the purpose of providing adequate anticipated transients without scram (ATWS) mitigation.

2. To satisfy the acceptance criteria for RCS overpressure events (i.e., Turbine Trip, Load Rejection, …), given the fact that the Steam Generator volume is not expected to be significantly affected and assuming that the main steam system design pressure will not be significantly changed, the relief capacity of the steam generator safety and relief valves should be increased. Without performing specific analyses, an increase in the order of the amount of the uprate can be tentatively assumed.

3. An increase in auxiliary feedwater (AFW) will be required to provide sufficient decay heat removal capability. This can be achieved in one of two ways:

   a. The capacity of the AFW system (for typical 4-Loop plants made of 2 Motor Driven AFW Pumps, MDAFWP, and 1 Turbine Driven AFW Pump, TDAFWP) could be increased proportionally to the increased power. This can either be achieved by replacing the AFW pumps, or by adding an additional 1 or 2 trains of MDAFWP (see below for the rationale under which adding a single MDAFWP train should be sufficient);

b. The reliability of the AFW system could be increased. It is current practice in Westinghouse analyses to assume that one AFW train (typically the large capacity TDAFWP) will not be available due to the single failure assumption, AND that an additional MDAFWP will not be available to address reliability concerns raised in the past by the NRC regarding availability of the AFW trains. One of the two trains is sometime credited to become available later in the transient following an operator action to align the “faulted” train. Plant procedures and technical specifications could be revised so that the analysis could credit for two trains of AFW immediately at the beginning of the transient. This solution, if possible, is preferable over the previous alternative since it will allow increasing the minimum AFW flow (used in this analyses) without affecting the maximum AFW flow (used for the analyses of the containment impact of a steam line break), thus minimizing the impact on the containment system of this uprate and relaxing the assumption included in Section 7.3 regarding the increase in AFW flow. Note that even if this solution is possible, replacement of the two MDAFWP to increase flow rate until an acceptable result is achieved may still be required. This will have to be assessed on a plant by plant basis.

4. Even under the assumptions listed in Section 7.3 (i.e., no increase in fuel stored energy and same DNB margins of existing plants), the increased power could lead to a higher peak fuel pellet average enthalpy during reactivity insertion accidents (RIAs). While advanced methods (ANCK-VIPRE) are available that provide significant margins, the NRC is evaluating a significant reduction in the existing limits (from 280 cal/g to values below 100 cal/g) and, thus, it is difficult to assess this issue at this time. It is recommended that additional consideration be given to RIAs at an early stage of a more complete assessment of the APUU.

5. ATWS considerations suggest that the need to install a diverse scram system (DSS) can be considered highly probable. Not only has a DSS been required in 10CFR50.62 for both B&W and CE plants, but also some Westinghouse PWRs have implemented this system. In addition, all advanced Westinghouse plants (AP600, AP1000 and IRIS) feature a DSS system. Installation of a DSS as part of the scope of the already extensive plant modifications that would be required for this program appears to be the lowest risk option to address ATWS concerns.

6. Hardware modifications will be required to achieve an acceptable response to small break LOCA (SBLOCA) events. The following two alternatives are suggested as possible modifications:

   a. Increase high pressure emergency core cooling system (ECCS) pump capacity or the number of pumps. In a typical four loop plant, the ECCS system includes two centrifugal charging pumps which can inject at pressures above the safety valve set-point of the pressurizer and two intermediate head safety injection pumps whose flow characteristics are similar but whose shut-off head is much lower – on the order of 1500 psia. (This is often referred to as an HP ECCS plant). For a large uprate, the ideal option would probably be to increase the size (capacity) of the intermediate head safety injection (IHSI) pumps. Even dramatically changing the size of these pumps should not be a huge economic penalty since it is the overall life cycle costs that become significant and not the initial capital costs. In other words, cost savings are usually only recognized if a component is eliminated and not if it's size is optimized, at least for the size changes being considered here. The charging pump size could be increased too, but this is not recommended for SBLOCA since 1) the IHSI pumps can accommodate this alone; and, 2) inadvertent SI with resultant pressurizer over-fill can become a challenging event.

      Note that this option is only applicable to plants with an IHSI systems (i.e., 4 Loop Plants).

   b. Another option would be to add an automatic depressurization system to either the primary or secondary side, as was done with AP-600/1000. This mitigates the SBLOCA transient because it reduces break flow and increases make-up flow. Because this plant is assumed to consist of active rather than passive mitigation systems, the more effective option would be to depressurize the secondary side since: a) it minimizes RCS inventory loss; b) recovery of reactor coolant is not necessary (little impact on containment); and, c) it would likely be more cost effective because of lower pressure piping requirements and non-RCS qualifications.

   c. It is also important to mention that Westinghouse is in the process of developing a best estimate SBLOCA (BE SBLOCA) evaluation model, based on the WCOBRA/TRAC code and on the BE LBLOCA methodology. While it is recognized that development and use of more advanced evaluation models will provide significant margins for the SBLOCA analyses, the magnitude of the considered uprate (25 to 50%) is such that hardware modifications will be required to achieve acceptable results in a postulated SBLOCA transient.

7. Within the limits of this evaluation, two hardware modifications would be required to achieve acceptable large break LOCA (LBLOCA) response:

   a. Changes to the accumulator to extend the duration and increase of the efficiency of the accumulator injection are recommended to provide an additional source of water injection to the core. A first possible set of modifications to the accumulator design would be similar to that of the APWR advanced accumulators. These advanced accumulators could be realized with simple modifications to the existing accumulator systems. Another possible modification to improve the efficacy of the accumulator for LBLOCA mitigation would be to reduce the cover gas pressure to delay accumulator injection closer to the end of the blowdown phase. This would maximize the efficacy of the accumulator by delaying the injection and reducing the injection water lost during the ECCS bypass phase. Note that this modification should be carefully evaluated for its possible impact on other events (e.g., small break LOCA).
   b. The total SI flow should be increased, as a first approximation proportionally to power, to guarantee that the reflood peak is mitigated, and, that the same occurs for the second reflood peak, if applicable. Note that increased SI flow will also prevent the peak cladding temperature (PCT) from remaining at high values for extended period of times, which in turn could challenge the local maximum oxidation (LMO) limits. In this case, changes to the high head safety injection (HHSI) or intermediate head safety injection (IHSI) would be inconsequential, since the reduction in pressure during a LBLOCA is so rapid that only modifications to the low head safety injection (LHSI) (that can provide larger amounts of flow for the same cost) are recommended.

8. Dose concerns connected with the APUU program should be addressed, where needed, mostly by refinement in the current evaluation models and, in particular, through the use of the Alternative Source Term (AST) methodology. An increase in the containment spray rate might be required to improve containment spray removal of activity. Also, to obtain acceptable results for the fuel handling accident analysis, it might be required for some plants to increase the shutdown time required prior to fuel movement. Since doses evaluations are impacted by plant and site specific characteristics, it is not possible to formulate generic lists.

9. Different containment concerns have been addressed in this review. In general, and considering that the APUU assumptions include a small to no increase in RCS and steam generator (SG) water inventory, it is concluded that possible critical issues are connected to an eventual increase in the AFW flow (that would impact the mass and energy release in a steamline break event) and the increased decay heat for long term containment cooling. The expert opinion is that acceptable results for containment response could be achieved by a combination of:

   a. Improved (less conservative) evaluation models: This is an area where significant margin exists in containment analyses.

   b. Plant modifications: possible plant modifications required to satisfy current licensing requirements.

7.3 Key Assumptions

The study documented in this report is based on a set of assumptions that limit the scope of the investigation, and that were defined on the basis of preliminary activities in the APUU program. The main assumptions are summarized below.

7.3.1 Core and Departure from Nucleate Boiling (DNB)

The following key assumptions on the Core are made in this study:

1. **DNB limitations are not considered**: One of the critical issues to be addressed to be able to support a large power uprate on existing plants is the capability of removing heat from the core without challenging the integrity of the fuel rods. In particular, a key requirement is that the DNB limits not be violated during normal and transient conditions (Condition I and II events from ANS/ANSI 18.2). Since this issue is not part of the scope for the APUU evaluation, it can only be assumed that as a "condition sine qua non" for such a program, heat removal by the core will be addressed elsewhere. Possible approaches would include:

   1.1 Adoption of novel fuel designs (e.g., annular fuel as proposed in a supporting MIT program);

   1.2 Introduction of ultra-thin rods;

1.3 Use of novel clad material (capable of high temperature operation that would eliminate DNB concerns).

2. **<u>Fuel Stored Energy will not increase significantly</u>**: Stored energy in the fuel is not only a key phenomenon in the evolution of Large Break LOCA, but any significant increase would make it impossible to satisfy the “no-centerline” melt requirement for Condition I and II events. Possible approaches would include:

   2.1 Adoption of novel fuel designs (e.g., annular fuel as proposed in a supporting MIT program);

   2.2 Introduction of ultra-thin rods;

   2.3 Use of new fuel forms with increased density/conductivity.

3. **<u>Discharge Burnup will be compatible with current (or future) limits:</u>** An increase in discharge burnup would lead to a potentially large impact on several key plant parameters (LOCA embrittlement limits, RAI limits, Source Term inventory, etc.) that are not addressed in this assessment. The assumption is equivalent to assuming that the fuel cycle will be shortened proportionally to the increase of power.

4. **<u>Core Neutronic Performance</u>**: Lacking any specific information, it is assumed that the neutronic parameters (shutdown margin, feedback coefficients, rod worth, insertion rates, etc.) for the uprated plant will satisfy the existing technical specifications limits. This assumption was discussed with core designers and confirmed to be acceptable for this stage of the program.

7.3.2 Reactor Coolant System

1. **<u>RCS Volume, with the exception of the pressurizer, will not be significantly affected:</u>** While any large uprate will require a replacement of the SGs to increase the heat transfer area, it is here assumed that the overall RCS volume will not be significantly affected. This assumption is consistent with current experience; and, is dictated by the need of not significantly affecting the plant footprint inside the containment. RSG for APUU currently being studied as part of this program; and, it is currently assumed that DELTA SGs, combined with a reduction in steam pressure, will be used to remove the increased heat generation. This assumption minimizes the short term effect on containment that comes from a primary side LOCA.

2. **SG Secondary Water Inventory will not be significantly affected:** This assumption has the same basis discussed above. It is also supported by experience with existing replacement SGs and by the need to limit the impact on the plant footprint. It is, however, to be noted that, while the SG inventory is not assumed to be affected, maximum AFW flow to the SGs will have to increase to allow sufficient decay heat removal capability. For preliminary containment studies, it can be assumed that AFW will increase proportionally to the power increase

3. **Operating Conditions**: SG replacement and eventual reactor coolant pump (RCP) replacements have been considered as part of the APUU studies. The need to reduce the increase in pumping power to acceptable levels will require an increase in the core temperature rise and a reduction in the core outlet temperature. The RCS Tavg will therefore be lower for the uprated plant than for the current plants. The same system pressure should be considered. A reduced Flow to Power ratio will characterize the uprated plant, with a final value that will depend on the decision of whether to replace the RCPs or not. The safety assessment should address the potential impact of variations in the RCS Tavg and Flow to Power Ratio.

7.3.3 Miscellaneous Assumptions

1 A range of different potential uprates is considered in this assessment from 25% to 50%.

2 The Reference Plant considered in this study is a 4-Loop Westinghouse plant assumed to be already uprated to the limits of the current technical basis.

3 Different Containment Systems and Safety Systems Configurations (i.e. ECCS) compatible with the Reference Plant will be considered.

4 If specific plant data are required for any calculation, Callaway data can be used as long as they are supported by additional considerations to justify the extension of the conclusions to other 4-Loop Westinghouse PWRs.

7.4 References

[1] American National Standard Institute N18.2, “Nuclear Safety Criteria for the Design of Stationary PWR Plants,” 1973.

[2] Westinghouse Electric Co., “AP1000 Design Control Document,” APP-GW-GL-700, Revision 2, April 29, 2002.

[3] NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, July 1981.

[4] WCAP-16009-P and WCAP-16009-NP, “Realistic Large Break LOCA Evaluation Methodology Using Automated Statistical Treatment of Uncertainty Method (ASTRUM),” May 2003.

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8 Auxiliary Systems (L.E. Conway, D.F. Dudek and E. Lahoda, WEC)

8.1 Introduction

The focus of this section is to identify modifications to the plant Nuclear Steam Supply Systems (NSSS) auxiliary systems needed to address key issues raised in the initial safety evaluation and to address the capability of the current auxiliary systems to perform required plant functions with the large plant power level uprate.

Section 8.2 provides a summary of the main conclusions of this study and focuses on the identified necessary plant modifications. To perform this evaluation, several key assumptions were made consistent with the overall basis of the project and are listed and discussed in Section 8.3. Finally, Section 8.4 documents the evaluations performed to reach the conclusions documented in Section 8.2.

The following analysts are responsible for the various parts included in this section:

Daniel F. Dudek	Section 8.4.1 (Plant Cooldown Performance)
Lawrence E. Conway	Overall section and Section 8.4 (Auxiliary System Uprate Design Assessments)
	Section 8.4.2 (Small LOCA Safety Injection Performance)
	Section 8.4.3 & 8.4.4 (Large LOCA Safety Injection Performance)
	Section 8.4.5 (Containment Cooling and Pressure Suppression Performance)
	Section 8.4.6 (Auxiliary Feed Water System)
	Section 8.4.8.2 (Spent Fuel Pool Cooling System)
E. Lahoda	Section 8.4.7 (Increased Activity Due to N16 Activation)
	Section 8.4.8.1 (Spent Fuel Pit Activity)

8.2 Summary of Results and Conclusions

Based on the results of the assessment documented in Section 7, it can be concluded that no NSSS auxiliary system feasibility issues have been identified from the point of view of safety considerations for the APUU (Advanced Power Ultra Uprate) program. From the point of view of maintaining sufficient functional performance of the plant in key areas, the following key items were identified in Section 7.2.

1. As discussed in the Safety Evaluation portion of this study (Section 7), the safety injection flow provided to the RCS cold legs following postulated SB LOCAs (small break loss of coolant accidents) should be increased to assure that the fuel uncovery time, that occurs during the clearing of the reactor coolant loop seals, is not extended. This uncovery period can be limited by providing increased pumped safety injection capability at ~1000 psig reactor pressure. To minimize the impact on plant equipment, this flow increase can be provided by increasing the capacity of the current intermediate head safety injection (SI) pumps. The capacity of these pumps is to be increased from the current pump runout flow rate of 650 gpm to 2000 gpm.

2. The reference plant residual heat removal (RHR), component cooling water (CCW), and essential service water (ESW) systems are capable of providing adequate heat removal for normal plant shutdown operations. These systems can cool the RCS from 350°F to 140°F in a reasonable time such that plant refueling operations will not be significantly impacted.

3. The safety injection flow provided to the RCS cold legs during the Injection Phase of accident recovery following a postulated large break LOCA (LB LOCA) should be increased to reduce the likelihood of downcomer boiling. This conclusion results from the safety evaluation review discussed in Section 7. The APUU uprate plant safety injection flow, following a postulated LB LOCA, can be increased in two ways with a minimum impact on the reference plant current safety injection system.

   First, the increase in capacity of the intermediate head safety injection pumps, discussed in Item 1 above, will provide an increase of at least 1000 gpm in the minimum net injection phase flow rate to the intact RCS cold legs following a postulated double-ended guillotine cold leg break.

   Second, the safety injection accumulator cover gas pressure and volume can be optimized to extend the duration of the accumulator injection such that less water is lost to the broken cold leg loop pipe. This enables the accumulators to participate in the initial portion of the core reflood. This type of optimization has been incorporated in advanced PWR designs by Westinghouse. With these two modifications, the injection performance will be improved, as recommended in the safety evaluation discussed in Section 7.

4. The safety injection flow provided by the current Safety Injection System (SIS) to the RCS cold legs during the recirculation phase of accident recovery following a large LOCA is more than sufficient for the APUU target plant power uprate. Note that the only requirement for this mode of operation is that the injection flow must exceed the rate at which water is boiled from the core region due to decay heat. Note that the significant increase in the size of the intermediate head SI pumps, discussed in Items 1 and 3 above, will require that the reference RHR pumps operate, in the recirculation mode of accident recovery, solely as booster pumps for the high head charging/SI pumps and the intermediate head SI pumps. This will enable one RHR pump to provide suction flow to two SI pumps (4000 gpm) and two charging/SI pumps (1100 gpm) while not exceeding its nominal runout flow of 5500 gpm. This scenario corresponds to the postulated failure of one of two RHR pumps during the recirculation mode of accident operation. Note that for the postulated failure of one of two entire trains of SI equipment, this modification will result in reducing the total SI injection flow during the recirculation mode, since the single RHR pump supplies all its discharge flow to the suction of the single operating SI pump and single operating charging/SI pump. However, the flow delivered by these two pumps is more than twice that required to match core boiloff due to core decay heat at the time switchover of the SI system to the recirculation mode of operation occurs.

5. An increase in auxiliary feedwater (AFW) flow rate will be required to provide sufficient decay heat removal capability for the APUU up-rate plant. This flow increase can be achieved without significantly increasing the flow to a faulted steam generator (namely, an SG with a postulated main steam line break), so as to not cause a large increase in the mass and energy released to the containment and to not cause excessive cooldown of the primary fluid.

6. The current reference plant containment and containment heat removal systems appear to provide sufficient margin such that the peak containment pressure following the worst postulated design basis event will not result in exceeding the containment design pressure. Furthermore, the current reference plant fan cooler/ESWS, RHR/CCWS/ESWS, and, containment spray energy removal are sufficient to provide adequate cooling and depressurization of the containment in the long term.

7. The spent fuel pool cooling system (SFPCS) pumps, HX, and the CCWS supply to the heat exchanger must be increased in size in order to maintain the SFP water temperatures within acceptable limits for personnel. These increases are due to the increased decay heat load due to the APUU thermal power increase and also due to the expected shorter fuel cycles which results in filling the spent fuel pool (SFP) at a faster rate with shorter times between refueling for the decay heat to decrease.

8. Based on the performance of the current reference plant containment spray system and containment fans coolers (with their associated CCWS and

ESWS heat removal capability), no increase in the containment heat removal capability is required even for the worst postulated accidents. Since there is significant margin in the reference plant between the current peak containment pressure and the containment design pressure, and, with the more sophisticated containment analysis techniques now available, it is likely that any increase in the RCS mass and energy released to the containment due to the APUU uprate can be accommodated by the current reference plant containment structure with no required modifications.

9. The remaining traditional auxiliary NSSS systems, namely, the Chemical and Volume Control System, the Boron Recycle System and the Waste Processing Systems will not be impacted by the APUU uprate increase in plant power output.

8.3 Key Assumptions

The main assumptions are summarized as follows:

8.3.1 Core

- **Discharge Burnup will be compatible with current limits** An increase in discharge burnup would lead to a potentially large impact on several key plant parameters (LOCA embrittlement limits, RAI limits, Source Term inventory, etc.) and is neglected in this assessment. The assumption is equivalent to assuming that the fuel cycle will be shortened proportional to the increase in power. Note that the increased surface area will likely eliminate the DNB issues but does not affect the source term inventory.

8.3.2 Reactor Coolant System

- **RCS Volume, with the exception of the pressurizer, will not be significantly affected** It is assumed that the overall RCS volume (with the exception of the pressurizer) will not be significantly affected. This assumption is consistent with current experience and is dictated by the need of not significantly affecting the plant footprint inside the containment. Also, it is assumed that DELTA 75 SGs, combined with a reduction in steam pressure, will be used to remove the increased heat generation. This assumption results in a reduction in the secondary side fluid energy and will minimize any longer term effects on containment that come from a primary side LOCA.

- **SG Secondary Water Inventory will not be significantly affected** While any large uprate will require a replacement of the SGs to increase the heat transfer area, but it is assumed that the secondary fluid volume will remain essentially unchanged. However, maximum Auxiliary Feed Water (AFW) flow to the SGs will have to increase to allow sufficient decay heat removal capability. For preliminary containment studies, it can be assumed that AFW will increase proportional to the power increase.

8.3.3 Miscellaneous Assumptions

- A range of different potential uprates is considered in this assessment, from 25% to 50%.
- The Reference Plant considered in this study is a 4-Loop Westinghouse plant, assumed to have been already uprated to the limits of the current technical basis.
- Different Containment Systems and Safety Systems Configurations (i.e., ECCS) compatible with the Reference Plant will be considered.
- If specific plant data are required for any calculation, Callaway data can be used as long as they are supported by additional considerations to justify the extension of the conclusions to other 4-Loop Westinghouse PWRs.

8.4 Auxiliary System Uprate Design Assessments

8.4.1 Plant Cooldown Performance

Residual Heat Removal System (RHRS)

The reference plant RHRS was analyzed by performing normal and safety grade cooldown cases using the current reference plant CCWS and ESWS designs and temperature bases. The intent of these evaluations was to minimize the changes to the existing reference plant fluid systems, while identifying issues that may affect the overall feasibility of the large APUU uprating. These analyses included review of the effect on the RHRS and the CCWS with expected ESWS water temperatures, as well as performance with the maximum ESWS temperature for safety related cooldown performance. Based on these analyses, the cooldown performance with the current RHRS equipment was optimized using the CCW/ESW systems as the preferred way to improve the plant cooldown performance, since these systems have significant design margin.

A Callaway calculation [1] was used as the basis for the APUU uprate evaluations. The RHR cooldown analyses were performed to establish the RHR system performance and to assure that this performance still met the typical

PWR design basis functional requirements and performance criteria for plant cooldown. The RHR cooldown analysis simulated the heat removal capability of the CCW and ESW systems. The input data to be used in this evaluation is described below.

Cooldown Start Temperature and Time

During plant cooldown operations, the RHR cooldown is typically initiated at a RCS temperature between 350°F and 325°F. For conservatism, the cooldown analysis was modeled according to the original design basis which initiated cooldown at 350°F. The design basis for normal cooldown assumes that the Reactor Coolant System is cooled by the auxiliary feed water (AFW) to the steam generators with steam dump to the main condenser. This mode of operation is used to cool the RCS at ~50°F/hr, from 557°F ($T_{no\ load}$) to 350°F in a four hour period after nuclear shutdown. Therefore, the RHR cool down analyses assume that RHRS operation is initiated at 4 hours after reactor shutdown, in order to maximize core decay heat since the specified RCS cooldown rate is normally limited to 50°F/hr.

Cooldown Final Temperature and Time Limit

For normal operation with two of two RHRS mechanical trains of equipment available, the design basis for the RHRS is, typically, to cool the RCS from 350°F to refueling mode temperature (140°F) within 20 hours after shutdown. However, this is not a regulatory requirement. This performance specification was chosen as the system design basis to minimize the affect of RHR cooldown on the refueling operations schedule.

For the plant safety grade cooldown, which is performed with only one of two mechanical trains available, the RHRS is typically designed to cool the RCS from 350°F to the "cold shutdown" temperature of 200°F within 40 hours after shutdown. This performance demonstrates that single train cooldown can be performed in a reasonable period of time. To meet this cooldown performance, the RHRS must cool the RCS from 350°F to the cold shutdown temperature of 200°F within 36 hours, starting at eight (8) hours after shutdown. This cooldown performance is demonstrated using the technical specification maximum expected service water temperature and realistic maximum auxiliary system heat loads, including the decay heat from fuel stored in the filled spent fuel pool.

Heat Exchanger UA

The computer code utilized for this evaluation, RHRCOOL, corrects the heat exchanger performance during the cooldown operation using the effectiveness-NTU method. The code adjusts the design UA to account for the effect of operating shell and tube flow rates that differ from the design flow rates.

Auxiliary Heat Load

In addition to the RHRS heat exchangers, the CCW also transfers heat from other auxiliary components within the NSSS to the ESWS. These auxiliary component heat loads impact the CCW temperature and, therefore, affect the CCWS's ability to cool the RHR heat exchangers and to meet the cooldown requirement. For the normal cooldown case, the assumed auxiliary heat load is 29.29E6 Btu/hr at an RCS temperature of 350°F and 10.34E6 Btu/hr when the RCS is cooled to 140°F. These heat load values are input into the cooldown computer code, RHRCOOL. However, for simplification purposes, the code models the heat load as linearly decreasing as a function of time; therefore, the heat load is incrementally decreased per hour until the final temperature and auxiliary heat load at 140°F is reached.

For the safety grade cooldown case using a single ESWS,CCWS, and RHRS mechanical train, the auxiliary heat load is conservatively assumed to remain constant over the duration of the RHR cooldown time since the RCS cooldown is limited.

Component Cooling Water (CCW) Temperature

The maximum allowable CCWS heat exchanger outlet temperature is conservatively limited to 120ºF during normal plant operation by the reactor coolant pump design which specifies that the CCW supply temperature to these pumps will not exceed 130ºF during each plant cooldown. This analysis includes cooldown evaluations with a maximum CCW temperature of 120ºF and with the allowable CCWS supply temperature increased to 130°F. This increase is consistent with the current reactor coolant pump design specification which allows the CCW temperature to be 130°F for 4 hours during cooldown operations.

Table 8.1 summarizes the input parameters for the RHR cooldown computer runs that were performed.

Table 8.1 - Input Parameters for Plant Uprate Cooldown Analyses.

Plant Parameter	Reference Normal Cooldown 2-Train	Reference Safety Grade Cooldown 1-Train	Case 2, Uprated Safety Grade. Cooldown 1-Train	Case 3A, Uprated Normal Cooldown 2-Train	Case 3B, Uprated Normal Cooldown 2-Train	Case 4A Uprated Normal Cooldown 2-Train	Case 4B Uprated Normal Cooldown 2-Train
Reactor Power, MWt	3565	3565	5137.5	5137.5	5137.5	5137.5	5137.5
CCW HX Design UA, MBTU/hr-°F	6.16	6.16	6.16	6.16	6.16	6.16	6.16
RHR HX Design UA, MBTU/hr-°F	2.3	2.3	2.3	2.3	2.3	2.3	2.3
RCS Actual Flow thru 1 RHR HX, Mlb/hr	1.565	1.519	2.75 (5000gpm)	2.0 (4000 gpm)	2.0 (4000 gpm)	1.565 (3130 gpm)	1.565 (3130 gpm)
CCW Actual Flow thru 1 RHR HX, Mlb/hr	3.8	3.8	3.8 (7600 gpm)	3.8 (7600 gpm)	3.8 (7600 gpm)	3.8 (7600 gpm)	3.8 (7600 gpm)
SW Actual Flow thru 1 CCW HX, Mlb/hr	6.75	6.75	6.75	6.75	6.75	6.75	6.75
CCW Actual Flow thru 1 CCW HX, Mlb/hr	5.2	5.2	5.2 (13,500 gpm)	5.2 (13,500 gpm)	5.2 (13,500 gpm)	5.2 (13,500 gpm)	5.2 (13,500 gpm)
SW Temp., °F	95	95	95	95	85	85	85
RCP Stop Temp., °F	160	160	160	160	160	160	160
Max. CCW Temp., °F	120	120	130	130	130	130	130
RCS Final Temp., °F	140	200	200	140	140	140	140
Auxiliary heat load at 4 hr, MBTU/hr-°F	29.29	29.29	29.29	29.29	29.29	29.29	29.29
Auxiliary heat load at 20 hr (2 train), MBTU/hr-°F	10.34	29.29	29.29	10.34	10.34	10.34	10.34
Auxiliary Heat Load at 36 hr (1 train), MBTU/hr-°F	N/A	29.29	29.29	N/A	N/A	N/A	N/A
RCP Power, MBTU/hr(T > 160°F)	20.09	20.09	20.09	20.09	20.09	20.09	20.09
RCS Heat Capacity, MBTU/°F	2.11	2.11	2.11	2.11	2.11	2.11	2.11
RCS Start Temperature, °F	350	350	350	350	350	350	350
Time Cooldown Initiated, Hrs	4	4	8	4	4	4	4
Maximum RCS Temperature Gradient, °F/hr	50	50	50	50	50	50	50
Resulting time to Cooldown, Hr. / Attachment	23.8 / G	39.8 / H	120 / B	50.2 / C	26.7 / D	76.7 / E	41.8 / F

8.4.2 Small LOCA Safety Injection Performance

8.4.2.1 Event Description

Following postulated small break LOCAs, the RCS pressure decreases due to the loss of mass and the expansion of the pressurizer steam space. This pressure decrease slows when the RCS pressure reaches the saturation pressure corresponding to the hot leg water temperature, but continues to decrease until it approaches the saturation pressure corresponding to the cold leg/SG water temperature (~1000 to 1200 psig) and stabilizes. The RCS continues to lose mass through the break, and depending on the break size, the water mass lost will exceed the emergency core cooling (ECC) injection flow provided by the charging and safety injection pumps for all but the smallest postulated breaks. The rate at which mass is lost from the RCS significantly decreases when the break location uncovers, and only steam is vented through the break. However, for a break in the RCS cold leg, this cannot occur until the RCP suction pipe loop is cleared of water and steam can travel from the SG to the break location. This clearing of the RCP suction loop water seal causes the water level in the reactor vessel to decrease and results in core uncovery in all but the smallest postulated LOCAs. The uprated core power plays a significant role in this sequence of events. This is especially true during the boil-off phase of the transient when the increased vapor flow rate from the core (due to the higher rated power) must be relieved through the break. With the uprated plant's higher decay heat power, this becomes more challenging since the increased boil-off rate drives up pressure in the RCS for a given break size. The increased volume of steam produced by the core also decreases the RCS depressurization rate. This makes the SBLOCA transient worse since break flow stays high while ECC injection flow remains low due to the higher system pressures. A typical small, cold leg LOCA sequence of events for the reference plant type is shown in Table 8.2.

As shown in the table for a 3 inch equivalent diameter break, the core begins to uncover at ~1300 seconds after break initiation. The core peak clad temperature occurs at 1830 seconds and the core is fully recovered at 2500 seconds. It should be noted that the safety injection accumulators do not provide any water for this postulated break size, since the RCS pressure does not decrease below the accumulator nitrogen cover gas pressure.

Table 8.2 - Typical Small Break LOCA Time Sequence of Events (1).

Break Size (equiv. diameter)	2 inch (Sec)	3 inch (Sec)	4 inch (Sec)	6 inch (Sec)
Break initiation	0.0	0.0	0.0	0.0
Reactor trip signal	18	8.00	5	3
Safety injection signal	35	17.5	13.5	10
Safety injection begins	64	46.5	42.5	39
Loop seal venting begins	1295	520	280	67
Top of core uncovered	N/A	1310	650	145
Cold leg accumulator injection	N/A	N/A	915	155
Peak clad temperature occurs	N/A	1830	940	159
Top of core covered	N/A	2500	1330	160

8.4.2.2 Mitigation Features

The emergency core cooling (ECC) components are designed so that a minimum of three accumulators, one charging pump, one safety injection pump, one residual heat removal pump and their associated tanks, heat exchangers, valves and piping, ensure adequate core cooling in the event of a design basis LOCA or to provide boration in the event of a steam/or feed water break accident. The redundant onsite emergency diesels provide emergency power to their associated train of electrically operated components (one charging pump, one safety injection pump, one residual heat removal pump and their support systems) in the event that a loss of offsite power occurs simultaneously with a LOCA.

The injection mode of ECC operation consists of the ECC pumps (charging pumps, safety injection pumps and residual heat removal pumps) and the containment spray pumps taking suction from the RWST and delivering to the reactor coolant system (RCS) and containment spray headers, respectively. The accumulators deliver water if the RCS pressure decreases below their nitrogen cover gas pressure.

The two centrifugal charging pumps deliver flow through a common boron injection header which branches into 4, 3-inch high head injection lines that each connect directly to one of the four RCS cold legs. Each of these injection lines contains a throttling device that is set by test to limit the runout flow of a single operating charging pump, to obtain equal flows through each injection line, and, to limit the amount of water spill to the postulated break (i.e., to maximize flow to the intact RCS cold legs).

The two safety injection pumps deliver water through a common header which branches into 4 lines that connect to the 4, 6-inch RHR pump return lines that each connect to one of four accumulator injection lines which then connect to one of the four RCS cold legs. Each of the four safety injection pump branch lines contains a throttling device that is set by test to again limit the runout flow of a single operating safety injection pump, to obtain equal flows through each injection line, and, to limit the amount of water spill to the postulated break (i.e., to maximize flow to the intact RCS cold legs).

As noted above, in the event of a small LOCA (for example, the 3 inch break), no water is provided by the accumulators to help limit the time that the core is uncovered. Likewise, the RHR pumps are not able to provide any ECC flow due to the elevated pressure of the RCS.

8.4.2.3 Evaluation

For small break LOCAs; the pumped ECC flow from the charging pump, whose injection piping connects directly to the RCS cold legs, may be part of the break and, therefore, it is assumed that the broken injection path spills directly to containment pressure. The ECC flow from the safety injection pump, however, does not spill to containment pressure since its injection path is not directly severed and remains at the RCS pressure. Based on the typical safety injection system performance for the reference plant type, the charging pump ECC flow delivery to the RCS at 1200 psig is only 22.75 lbs/sec (165 gpm) and the flow spilled to containment through the broken injection line is 26.5 lbs/sec (192 gpm). The ECC flow delivered from the current safety injection pump is 25.83 lbs/sec (187 gpm) and 8.61 lbs/sec (or ¼ of the total pumped flow) is assumed to spill to the break.

Thus, the total ECC flow delivered for the 3 inch break during the time of core uncovery is only ~50 lbs/sec at an RCS pressure of 1200 psig. At an RCS pressure of 1000 psig, the delivered flow increases somewhat, to ~62.5 lbs/sec. As the core uncovers and as the core decay heat decreases with time, the core boil-off rate also decreases. This causes the RCS pressure to slowly decrease, and, at some point, the injection flow is sufficient to match the core boil-off rate and the RCS water inventory begins to increase.

For a significant power uprate, as is being considered here, the core decay heat will be proportionally higher and will require that the ECC flow be proportionately increased. However, the increased steaming rate would also cause the RCS pressure to be proportionately higher if all the steam were vented through the break. Fortunately, the SGs will limit the RCS pressure increase to ~1200 psig by condensing a portion of the core boil-off while secondary side steam is relieved through the SG safety valves.

For the 150% uprate power level, the 3 inch break case will result in a RCS pressure of 1200 psig with the SGs condensing steam since the break flow area is less able to initially vent all the core boil-off. To be conservative, the ECC flow should be increased to match the uprated core boil-off rate. This results in a required ECC flow of ~140 lbs/sec at 1200 psig. This increased ECC flow will result in improved LOCA mitigation for the 3 inch break versus the current reference plant.

It is clear that it is not desirable to increase the charging pump capacity to increase the ECC flow, since more than ½ of its pumped flow spills to the containment with the present injection line arrangement. Also, as pointed out in the safety evaluation, an increase in the charging pump capacity will result in more rapid overfill of the pressurizer during some transients. Also, as noted above, the RHR pumps are unable to provide any ECC flow at this time due to the elevated RCS pressure. Thus, the increase in ECC flow should be provided by the safety injection pumps. Accounting for the charging pump flow contribution (22.75 lbs/sec) and the spilled flow from one of the four safety injection pump injection lines, the 150% uprate safety injection pumps should be designed to deliver ~155 lbs/sec (1100 gpm) at ~1200 psig. A comparison of the current reference plant safety injection pump parameters versus the pump required for the uprated plant is provided in Table 8.1.

This increase in safety injection pump size can be incorporated in the uprate of the reference plant with minimal impact on the rest of the ECCS. The ECC capacity is increased with no required changes to the charging and RHR pumps. The only piping affected is the safety injection pump suction pipe that branches out of the large RWST discharge line that provides suction flow to all the ECCS pumps, the SI pump discharge piping that connects to the four RHR return lines, and, the piping from the RHR pump discharge lines that provides suction flow to both the charging and safety injection pumps during the recirculation phase of accident recovery. These piping changes are illustrated in Figure 8.1 and Figure 8.2. Additional discussion on these increased capacity safety injection pumps is provided in the discussion on large LOCA ECCS performance, where the larger SI pumps again play a role in the uprated plant meeting the large break ECC flow requirements.

An important aspect in the above described increase in safety injection pump capacity is the fact that the recirculation phase of accident recovery must be modified. This modification will be described in the discussion on the large break LOCA performance for the uprated plant. Another aspect of the increase in the capacity of the SI pumps is that they do result in an increase in required pump horsepower. This horsepower increase must be reflected in the sizing of the two emergency diesel generators; however, this increase is offset by the decrease in horsepower required by the uprated plant’s auxiliary feed water system which utilizes smaller motor-driven feed water pumps.

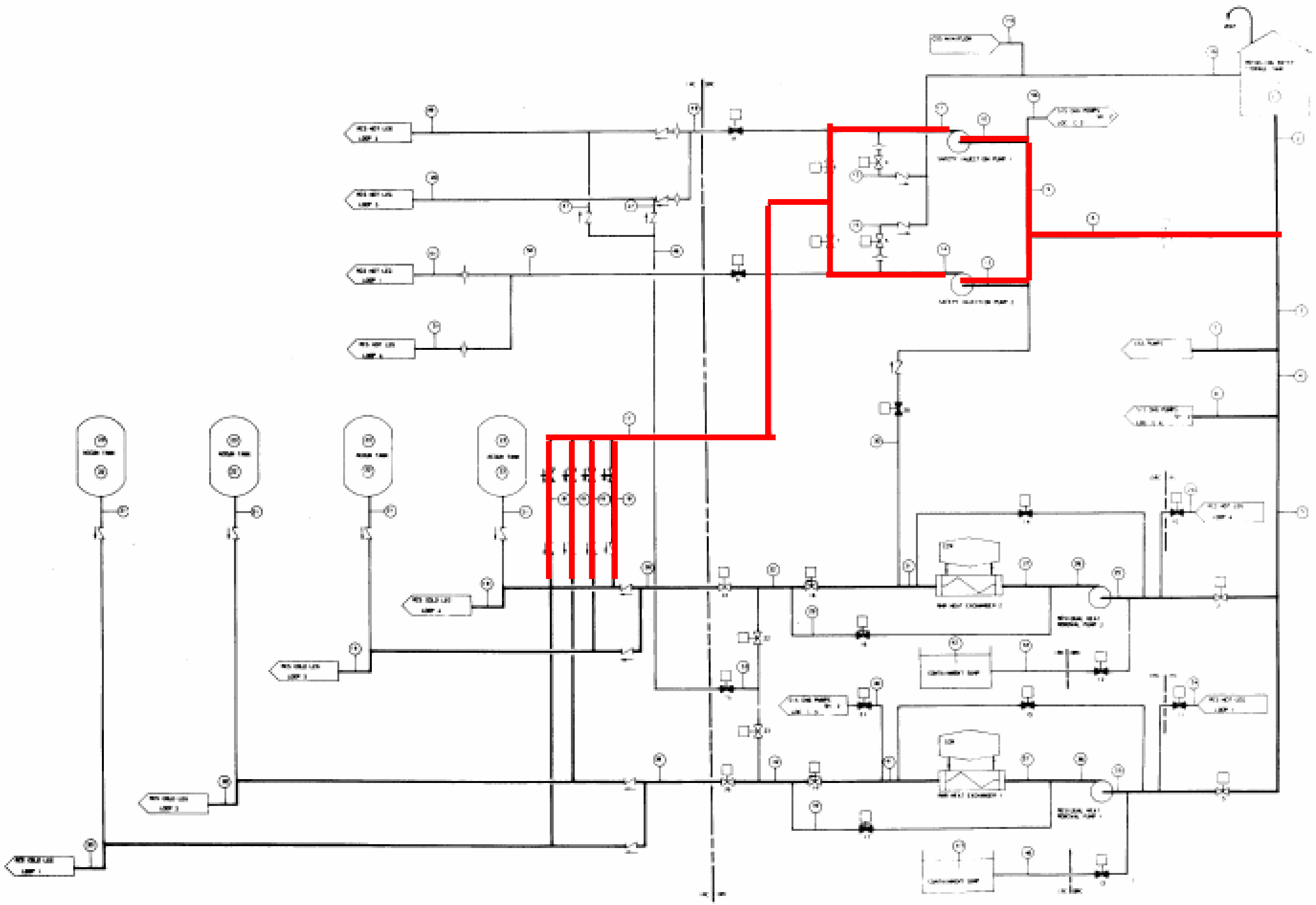

Figure 8.1 - Increased Size Safety Injection Pump Piping – Injection Phase.

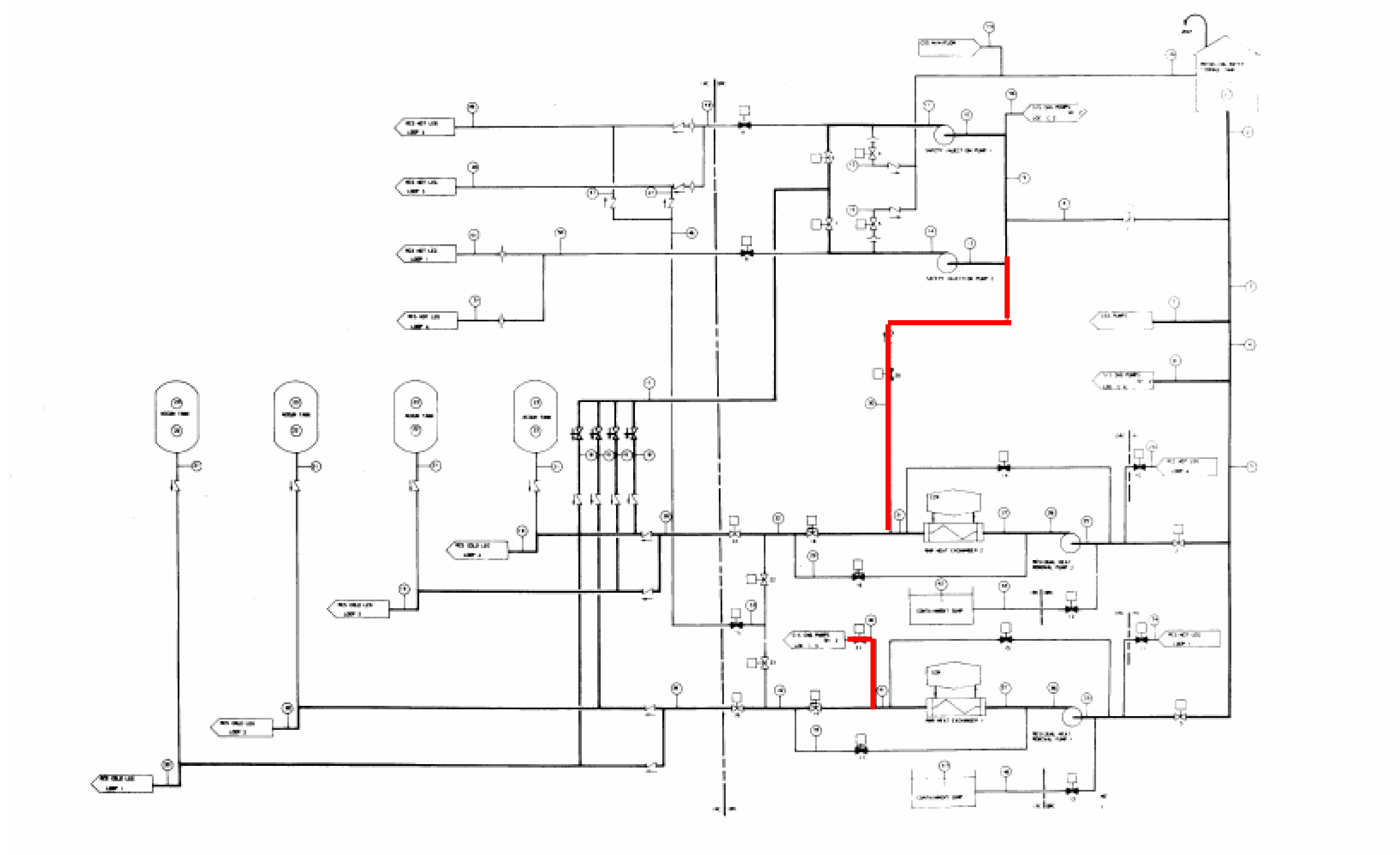

Figure 8.2 - Increased Size Safety Injection Pump Piping – Recirculation Phase.

8.4.3 Large LOCA Safety Injection Performance (Injection Phase)

8.4.3.1 Event Description

A large break LOCA (LB LOCA) is characterized by a rapid loss of reactor coolant system inventory and rapid depressurization of the RCS. This large mass and energy release from the RCS results in the rapid pressurization of the reactor containment which will be discussed separately in Section 8.4.5.

The limiting large break LOCA, for PWRs in general and Westinghouse PWRs in particular, is the postulated double-ended, guillotine break of an RCS cold leg loop pipe (DEG CL LOCA). This postulated break not only results in the loss of almost the entire RCS water inventory, but also results in the spill of all the safety injection flow delivered to the broken cold leg. In addition, a significant portion of the water delivered from the safety injection accumulators to the intact cold legs is initially spilled to the break also, due to high velocity fluid flow up through the reactor vessel downcomer to the break.

A LBLOCA event and the re-flooding of the core to limit the peak fuel cladding temperature typically includes the following phases:

- The blowdown phase in which the RCS pressure rapidly decreases due the expulsion of liquid and stream and leads to an uncovered core.
- The bypass phase in which water injected from the accumulators, which begin injecting when the RCS pressure decreases to less than the accumulator cover gas pressure, is ejected from the top of the RV downcomer through the break.
- The refill phase in which the RV lower head and downcomer are re-filled with water. This phase begins when the reverse flow though the core decreases sufficiently for injected water to begin to flow down the downcomer and ends when the RV is filled to core bottom elevation (bottom of core uncovery).
- The re-flood phase in which the continued injection of water results in an increasing water inventory in the core region. As the water/steam mixture level increases, the core clad temperature increase is slowed. Continued water injection eventually reaches the elevation of the peak clad temperature, terminating the temperature excursion and finally results in re-flooding the entire core.
- The final stage of the initial accident mitigation results in steam boil-off from the flooded core region, with the steam being vented from the steam generator side of the broken loop.

The temperature of the reactor core fuel cladding during the initial portion of the blowdown phase of the accident at first decreases, following nuclear shutdown, and follows the fluid saturation temperature which decreases with decreasing system pressure. When the blowdown phase is complete, there is little flow through the core region, which may actually have no liquid present, and the fuel begins to heatup due to the core decay heat with little or no heat removal occurring. Therefore, it is important for the ECCS to provide sufficient water following the end of bypass to refill the reactor vessel lower plenum and downcomer and initiate reflood of the core region.

Once the reflood of the core region begins, the quenched lower portion of the fuel produces steam which provides limited cooling to the upper, unquenched portion of the fuel. As reflood progresses, this steam flow provides sufficient cooling to slow the rate at which the unquenched fuel temperature is increasing. When the lower ½ to ¾ of the core is wetted, the peak fuel cladding temperature location is wetted and the temperature increase is stopped. Continued reflooding of the core region continues until the collapsed liquid level is at the cold leg elevation. With the collapsed liquid level in the core region at this elevation, the amount of water required from the ECCS is essentially that required to makeup for core boil-off and moisture carry-over from the core region into the hot leg of the broken loop. Additional water is assumed to just spill from the broken cold leg into the containment.

8.4.3.2 Mitigation Features

The operation of the ECCS during the accident recovery from a LB LOCA can be generally summarized as follows:

- Accumulator injection initiates when the RCS pressure decreases to less than the accumulator cover gas. Since the RCS pressure continues to decrease rapidly, accumulator injection rapidly increases and quickly refills the RV lower head and downcomer, once the end of bypass has occurred. It is noted that, before the end-of-bypass, when the blowdown through the reactor vessel side of the broken cold leg is still in progress, the water injected from the accumulators is largely lost out through the broken cold leg. In addition, the flow from the accumulator attached to the broken loop is assumed to spill to containment.

  Thus, it is noted that a large portion of the total water injected by the four safety injection accumulators is spilled to the break.

- When the accumulator injection is completed (~1 minute), the ECCS pumped injection flow must be sufficient to reflood the core region at a rate that results in requenching enough of the core to terminate the fuel clad temperature increase before the peak clad temperature limit is reached. This is accomplished by one RHR, one charging pump, and one SI pump with the 1 of 4 injection flow paths connected to the broken cold leg spilling to the containment. A single mechanical train of the ECCS is utilized to represent the worst single failure, namely, the failure of one of two of the AC electrical power trains. The RHR, Charging, and SI pumps all initially take suction from the refueling water storage tank which is typically located outside of the reactor auxiliary building in the yard.

For the reference plant the nominal ECCS flow rate delivered by one of two mechanical trains to the three intact cold legs (with the containment and RCS pressure assumed to be 0 psig) is summarized below.

- Residual heat removal pump – 4125 gpm
- Charging pump – 412 gpm
- Safety injection pump – 506 gpm

Note that higher containment pressures decrease the ECCS flow that is spilled to the broken cold leg and increase the amount of ECCS flow delivered to the intact cold legs. Also, higher reactor coolant pressure (versus containment pressure) results in an increase in the ECCS flow spilled to the broken cold leg and a decrease in the flow delivered to the intact cold legs.

8.4.3.3 Evaluation

The uprated plant LB LOCA behavior will not be significantly different than the general scenario described above. However, the proportional increase in core decay heat will shorten the time it takes for the uncovered fuel temperature to increase from the temperature that exists at the end of blowdown to the allowable fuel clad temperature limit of 2200°F (~1200°C). Therefore, the time required for the ECCS to refill the lower head and downcomer and reflood the core sufficiently to terminate the fuel cladding temperature increase must be reduced by at least 1/3 with a 150% power uprating (this assumes that the fuel elements mass and compositions are similar to the current reference plant design).

Based on the discussion above, this could be accomplished by increasing the pumped ECCS flow capacity by at least 33%. However, as noted in Section 8.4.2, the only ECCS modification required for small LOCA mitigation, was to increase the capacity of the safety injection pumps. The larger SI pump(s) increases the pumped ECCS delivered flow by ~20% following a postulated LB LOCA, following the completion of accumulator delivery.

Therefore, in order to increase the ECCS flow delivery during the critical time between the end-of-bypass and when the core clad peak temperature occurs, the accumulator delivery characteristics will need to be modified to allow the accumulators to deliver water slower over a longer time. This has been done on advanced PWR designs whereby the amount of accumulator flow lost prior to the end-of-bypass has been reduced and the refill time has been slightly extended, but the accumulators are still delivering and contribute significantly to the water needed to reflood the core and terminate the core clad temperature increase. In fact, some advanced plant accumulator delivery characteristics are so improved that the LB LOCA analysis has been simplified to include only the accumulators for accident mitigation. In these analyses, the accumulators reflood the core and terminate the core clad temperature increase with no pumped ECCS flow assumed. This same strategy will be employed on the uprated plant to limit the LB LOCA peak clad temperature.

Note that the optimized accumulator delivery characteristics and the increased injection flow rate provided by the larger safety injection pumps also addresses the issue raised in the safety analysis about minimizing the potential for boiling in the downcomer during the initial stages of LB LOCA recovery.

8.4.4 Large LOCA Safety Injection Performance (Recirculation Phase)

8.4.4.1 Event Description

During the initial injection phase of accident recovery, the ECCS pumps (charging pumps, safety injection pumps, and RHR pumps) all take suction independently from the refueling water storage tank (RWST). As described above in the injection phase of large LOCA recovery, the injection flow from these pumps is relied on to reflood the core after the SI accumulator injection is completed. When the RWST is emptying, the ECCS pump suction source is re-aligned from the RWST to the now flooded containment sump. Due to the low elevation of this water source, and since the sump water may be at or near saturation pressure, only the RHR pumps typically take suction from the containment directly. The charging pumps and the SI pumps rely on the RHR pump(s) to act as a booster pump and provide their suction flow.

8.4.4.2 Mitigation

During the recirculation phase of accident recovery following a large break LOCA, the ECCS flow required to be delivered to the reactor vessel is reduced as compared to the injection phase. In the reference plant original design, the injection flow path resistance associated with each RHR pump is increased by closing the low resistance “cross-over” line between the two RHR pump discharge lines as part of the injection to recirculation mode switch-over procedure. This limits the injection capability from a single operating RHR pump, but ensures that the single operating RHR pump can supply suction flow to both operating charging pumps (2 x 550 gpm), both operating SI pumps (2 x 675 gpm), and still provide ~3000 gpm directly to cold legs without exceeding its 5500 gpm runout flow limit. Following a postulated LB DECLG LOCA, with the reactor coolant system and containment pressures at 0 psig, and with an assumed loss of one mechanical train, the ECCS nominal pumped delivery is as follows:

- One charging pump with 1 of 4 injection lines spilling 412 gpm
- One safety injection pump with 1 of 4 injection lines spilling 506 gpm
- One RHR pump with 1 of 4 lines spilling 3000 gpm

Note that this flow rate greatly exceeds the amount of water required to maintain core cooling since it is approximately a factor of six (6) times greater than the core boil-off due to decay heat at 15 minutes after accident initiation. This is chiefly due to the fact that the sizing bases for each of these ECCS pumps is based on more limiting requirements in response to the whole spectrum of transients and accidents considered in the plant design.

8.4.4.3 Evaluation

Since, the uprated plant requires a significantly larger SI pump (1800 vs. 675 gpm, as discussed above), the role of the RHR pumps in the recirculation mode of operation must be re-defined, since a single operating RHR pump will no longer be able to act as both a suction booster pump for two charging pumps (2 x 550, or 1100 gpm) and two larger SI pumps (2 x 1800, or 3600 gpm) envisioned in the uprated plant and provide flow directly to the cold legs without exceeding its 5500 gpm runout flow limit.

Therefore, the RHR pumps in the uprated plant ECCS will operate solely as a booster pump for the charging and larger SI pumps. This will be accomplished by isolating the RHR injection lines to the cold legs as part of the injection phase to recirculation phase switchover procedure. This will require that additional isolation valves be installed on the RHR pump discharge piping, downstream of the RHR heat exchangers, to assure that this isolation can be accomplished assuming the worst single failure scenario.

With this revised role for the RHR pump(s), with the worst case single failure (the loss of one complete train of ECCS equipment) with one cold leg spilling to containment, the ECCS delivered flow will be provided by one charging pump (412 gpm) and one of the increased size SI pumps (1350 gpm). These two pumps deliver a total of 1760 gpm which is only about one-half of the 3918 gpm provided in the current reference plant design. However, this modification to the role of the RHR pump will have no adverse impact on the role of the ECCS during the recirculation phase of accident recovery, although ECCS flow is reduced, since the flow delivered to the reactor vessel is still approximately twice the uprated core decay heat at 15 minutes. Therefore, the uprated plant modified ECCS is capable of both continuing core reflood, if required, and can easily maintain the reflooded core in a flooded condition.

Another impact of this modification is that the ECCS injection flow through the RHR heat exchanger is reduced during the recirculation mode of accident recovery. For example, in the worst single failure case cited above, the flow from a single operating RHR pump through the RHR heat exchanger will be ~(1800 + 550, or 2350 gpm) as compared to 4225 gpm in the reference plant. This reduction in flow through the RHR heat exchanger will reduce the amount of heat that is removed from the pumped water. Since this water is being recirculated from the containment, the amount of heat being removed from the containment is slightly reduced. This reduction will be considered in the discussion on the containment systems for the uprated plant, below.

8.4.5 Containment Cooling and Pressure Suppression Performance

8.4.5.1 Containment Structure

The reference plant containment structure has a significant amount margin in that the calculated peak, post-accident, containment pressure during the blowdown of the reactor coolant system following the worst postulated LOCA is only <48 psig, versus the containment's 60 psig design pressure. Therefore, the reference plant containment will be able to accept the increased mass and energy input expected from the up-rated reactor coolant system during the blowdown phase of the accident without exceeding the current containment design pressure.

Figure 8.3 provides a plot of the reference plant containment pressure versus time for the worst postulated LOCA. As shown the peak containment pressure is 47.3 psig and this pressure is reached at 134 seconds during the blowdown of the reactor coolant system following accident initiation. Since the containment design pressure is 60 psig and since the up-rated plant average reactor coolant temperature is not changed significantly, the reference plant reactor coolant system mass, which directly impacts the blowdown mass and energy release, can be increased by 30%. This is more than sufficient margin to accept the projected up-rated plant increased reactor coolant system pressurizer size.

It is noted that for plant designs with little margin to containment design pressure, the up-rated design (with larger pressurizer) can only be accommodated by changing the postulated LOCA design basis from an instantaneous, double-ended, guillotine break of the loop piping to a less severe break. Such a change in the plant design basis is not without precedence in that current plants have licensed the acceptability of "leak before break" for large piping in order to simplify piping supports and restraints. However this licensing approach has not been carried through to the actual analysis of the containment pressure, which still considers instantaneous breaks for the containment analyses.

The containment structure must also consider the postulated steam line break event which also pressurizes the containment. However, for this event the mass and energy released into the containment during the initial blowdown of the faulted steam generator will not be significantly larger than that of the reference plant. This is because the secondary water mass contained in the up-rated steam generator is essentially unchanged from that of the reference.

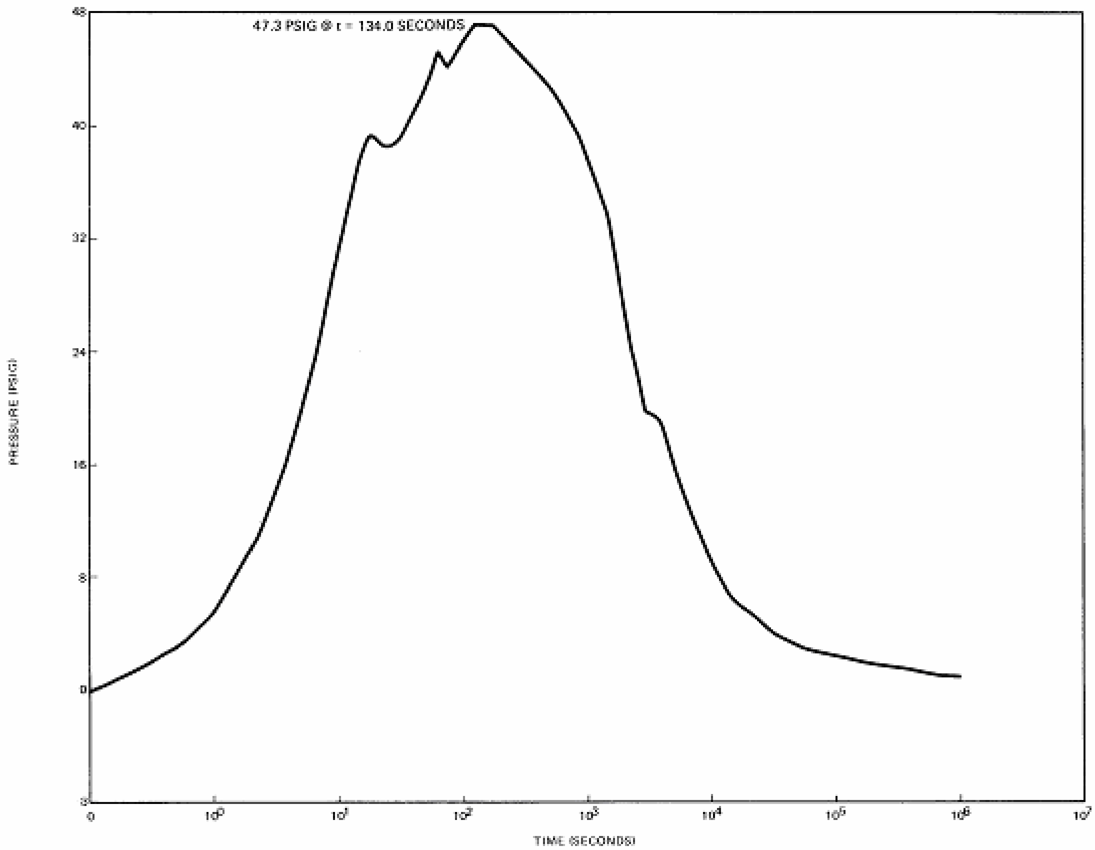

Figure 8.3 – Reference plant postulated LOCA event.

8.4.5.2 Containment Heat Removal Systems

Based on the performance of the current reference plant containment spray system, residual heat removal system, and containment fans coolers (with their associated CCWS and ESWS heat removal capability), there is no required increase in containment heat removal following even the worst postulated accidents for the APUU up-rate in reactor power.

Based on the reference plant safety analyses, the heat removal rate from the containment, with minimum safeguards equipment available is as follows:

- 1 of 2 Containment Spray System pumps delivering ~3100 gpm of spray water at 60°F, will remove 319E6 Btu/hr from the containment atmosphere @ 47.3 psig (~266°F).

- 2 of 4 Containment Fan Coolers remove 210E6 Btu/hr @ 47.3 psig (~266°F).

- 1 of 2 Residual Heat Removal System Heat Exchangers remove 160E6 Btu/ hr @ 20 psig containment pressure (at the time recirculation is initiated).

Thus during the initial injection phase of accent recovery, the containment fan coolers and the containment spray minimum heat removal rate can match the up-rated core decay heat within 10 minutes after accident initiation. This performance does not take credit for the fact that the up-rated plant containment pressure and temperature will be higher than the reference plant values on which these heat removal rates are based. It would be expected that this heat removal capability would be increased by ~10% to 580E6 Btu/hr at the containment design pressure and the temperature corresponding to the steam partial pressure.

This excess capability is also shown in Figure 8.4, which shows the post-accident energy balance for the reference plant. Note that at the time that the residual heat removal system begins to remove heat (~1700 seconds) which marks the end of the injection phase and the beginning of the recirculation phase of accident recovery, the total energy absorbed by the reference plant structures and systems is ~650E6 Btu. This energy exceeds the total enthalpy of the reactor coolant system water mass and the integrated decay heat from the up-rated plant core, which totals 550E6 Btu.

During the recirculation phase of accident recovery, which can occurs as early as ~1700 seconds in the reference plant, the minimum set of safeguards equipment is still able to remove sufficient heat from the containment to assure that the containment pressure continues to be decreased. In this mode of accident recovery, heat continues to be removed from the containment atmosphere by the fan coolers, while the residual heat removal system removes heat from the containment sump water. If we assume that the containment pressure is at the reference plant peak pressure of 47.3 psig, the heat removal rate from the containment, with minimum safeguards equipment available is as follows:

- 2 of 4 Containment Fan Coolers remove 210E6 Btu/hr.

- 1 of 2 Residual Heat Removal System Heat Exchangers removes 190E6 Btu/ hr.

This heat removal rate, 400E6 Btu/hr, exceeds the uprated plant core decay heat of ~360E6 Btu/hr at 1700 seconds thus assuring that the containment pressure (and temperature) will continue to decrease in the long term.

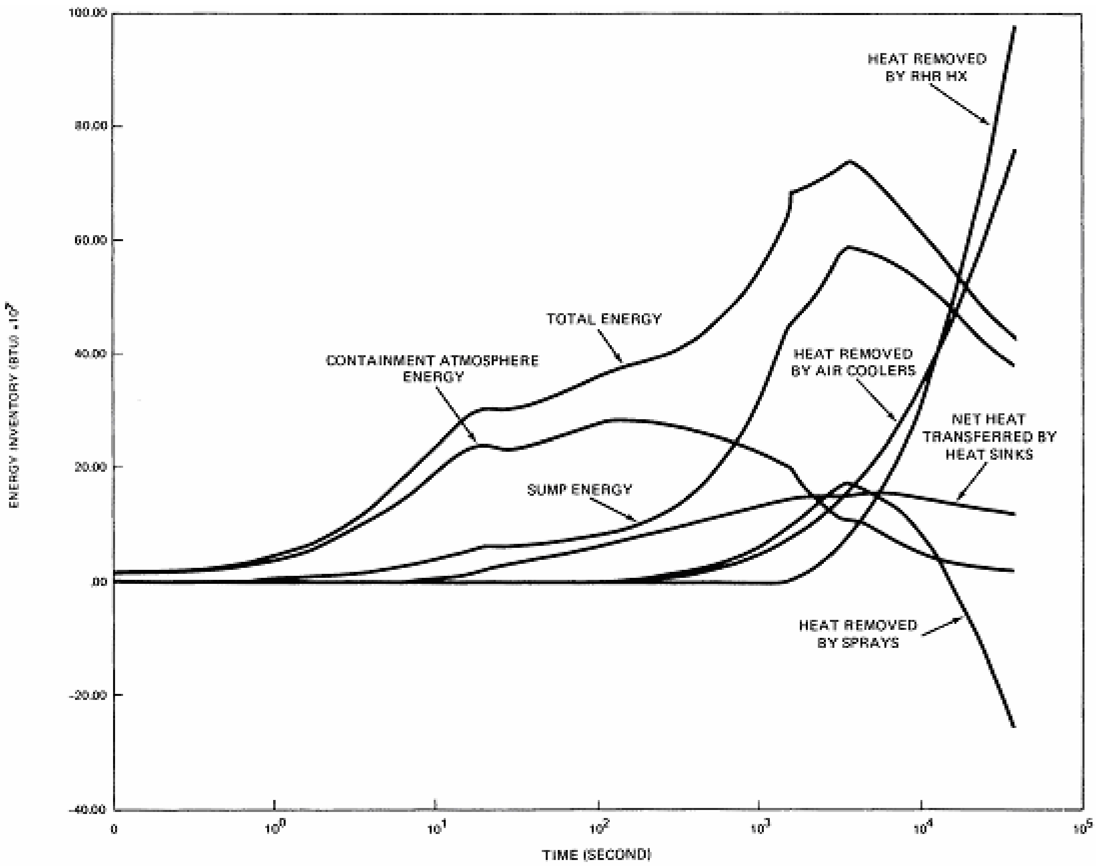

Figure 8.4 - Reference plant postulated LOCA event.

8.4.6 Auxiliary Feed Water System

The auxiliary feed water system (AFWS) of the reference plant consists of three (3) pumps which take suction from the condensate storage tank and deliver water to the four steam generators. Two of these pumps are motor driven and one pump is a turbine driven pump. The turbine driven pump driver is supplied steam from either of two steam generator main steam lines. The two turbine driven pump steam supply lines connect to the main steam lines upstream of the main steam isolation valves, so that steam can be available even if the main steam lines are isolated. The AFWS is a safety grade system that is relied on to provide sufficient feed water to the steam generators to remove decay heat, with or without off-site power available, and with the worst single failure assumed. In addition, the steam turbine driven auxiliary feed water pump can provide feed water even in the event of a station blackout. Each AFW motor driven pump can provide flow to two steam generators, while the larger turbine driven pump is designed to provide flow to all four steam generators.

For the APUU up-rated plant power level, the auxiliary feed water delivered flow must be increased in proportion to the increase in core thermal power in order to match the core decay heat. For example the reference plant turbine driven feed water pump design discharge flow would increase from 1145 gpm @ 1400 psig to 1850 gpm. Likewise, the motor driven pump discharge flow would increase from 575 gpm to 925 gpm. These large increases in pump flow rate could be accommodated by adding two small motor driven pumps and a second turbine driven feed water pump along with appropriate increases in the feed water piping and valves. However, the cost and complexity of interconnecting and controlling six AFWS pumps, 4 motor driven and two turbine driven pumps, and the cost associated with providing emergency diesel generator capacity for the added motor driven pump capacity would be unacceptable.

Therefore, it is recommended that the APUU up-rate would include replacing the current AFWS pumps and associated piping valves and controls with a properly sized four pump AFWS. This four pump system would consist of two motor driven and two turbine driven pumps, and would be similar to the AFWS's that have been designed for the newest, large PWRS that are currently being built in Europe and Japan. These four pump systems feature controls to minimize the delivery of water to a faulted steam generator or postulated broken feed water line, thus minimizing the mass and energy input into the containment following a postulated main steam line break inside containment. Also the four pump AFWS provides a large improvement in auxiliary feed water reliability which decreases the probability of core damage events in the plant risk assessment.

The reference plant has features which make the replacement of the current 3-pump AFWS with a 4-pump system easier. One such feature is that the reference plant already includes redundant steam supply lines for its single turbine driven pump. Thus, a steam line connection already exists for two independent turbine driven pumps. Additionally, the reference plant motor driven pumps are each piped to two of the four steam generators and are not header to all four steam generators.

The most important aspect of the 4-pump AFWS design is that the size of the individual pumps can be reduced relative to a 3-pump system. For example, in the event of a station blackout, two turbine driven pumps are available instead of one. Another example would be a postulated main steam line break, which eliminates the use of one turbine driven pump, still has two AFWS pumps available after a single failure is assumed to make one of the three remaining pumps unavailable. This added redundancy allows the individual pumps to be downsized significantly compared to upsizing the current AFWS. A detailed cost/benefit analysis should be performed to establish whether the current two motor driven pumps should be re-used in the APUU uprate with two smaller turbine driven pumps, or if additional downsizing can be done to reduce the horsepower load on the reference plant emergency diesels.

8.4.7 Increased Activity Due to N16 Activation

In a water-cooled nuclear system, the radionuclide N16 (with a half life of about 7 seconds) is produced by an (n,p) reaction on O16. The N16 concentration mainly depends on:

1. The coolant transit time which could be slightly smaller (<25%) in the uprated plant.
2. The neutron flux which is higher (25 to 50%) because of the higher power density.

The power uprate will thus have a moderate impact on the production of N16 and results in a slight increase of the N16 associated activity. However, the impact on access at power is probably negligible since the neutron fields tend to dominate the radiation fields inside containment during power. After the power uprate, some local areas outside containment (such as on the side opposite the loop areas, where the shielding is designed to limit the dose rates to low levels that are consistent with continuous access) may not meet suitable requirements. These areas could be addressed by adding additional local shielding or having different area radiation posting, and/or access restrictions/limitations.

8.4.8 Spent Fuel Pool

8.4.8.1 Spent Fuel Pit Activity

Calculations were performed by using the Origen2.00/SCALE Code to calculate the residual activity and heat load as a function of: (1) time; and, (2) coast down. These calculations were carried out to determine the potential effects on the residual heat removal system and on the Spent Fuel Pit heat removal system due to the increased power. Comparisons were carried out between a baseline fuel operated for 660 days at 36 MW/mtU with the parameters for a 17x17 PWR fuel assembly with 4.8 wt% ^{235}U enrichment and a high heat duty fuel operated at 150% of the baseline, also at 4.8% enrichment. Several different “Coast Down” options were used:

(a) No coast down: 440 days at 54 MW/mtU;

(b) 1 day coast down: 439 days at 54 MW/mtU and 1 day at 36 MW/mtU;

(c) 7 day coast down: 433 days at 54 MW/mtU and 7 days at 36 MW/mtU.

The cool down time to achieve a residual heat production level in the high heat load fuel that is comparable to a 2 day heat load of the baseline fuel (2×10^5 watts/mtU) was determined from Figure 8.5 to be as follow:

(a) ~6.1 days for the no coast down option;

(b) ~6.1 days for the 1 day coast down option;

(c) ~5 days for the 7 day coast down option.

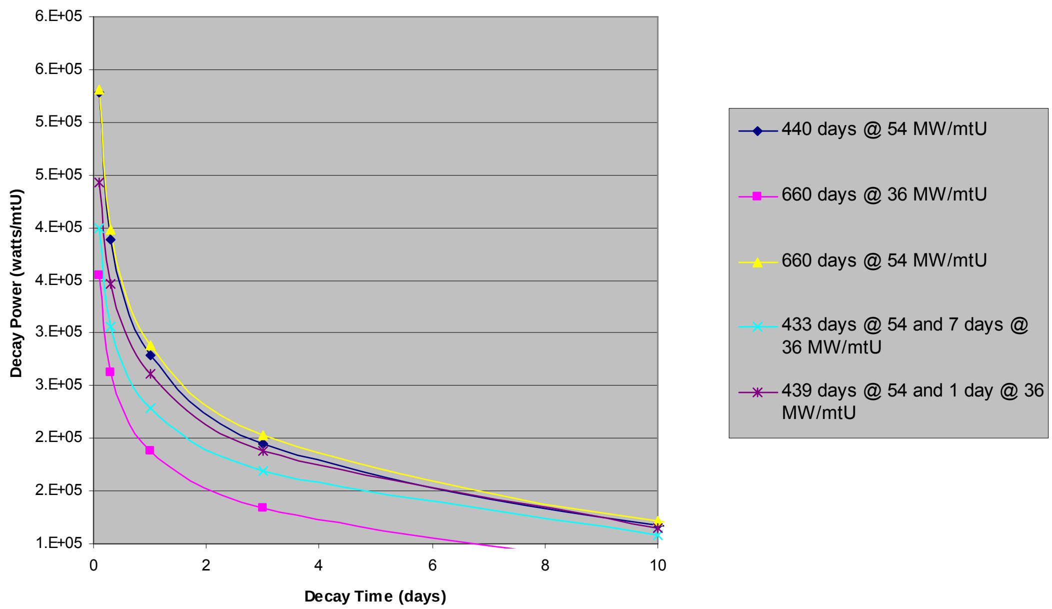

Figure 8.5 – Decay Power (Watts/TonU) versus time [Days].

The heat load as a function of coast down approach was calculated at the one year point. This was to determine the additional heat load that the Spent Fuel Pit would have to dissipate. The results listed in Table 8.3 indicate that there is about a 20% increase in heat generation rate for the higher rated fuel, regardless of the coast down procedure that is applied.

Table 8.3 – Decay Power (watts/mtU)

Decay Time (days)	1	3	10	365
440 days @ 54 MW/mtU	2.78E+05	1.95E+05	1.17E+05	9.23E+03
660 days @ 36 MW/mtU	1.89E+05	1.33E+05	8.12E+04	7.72E+03
660 days @ 54 MW/mtU	2.89E+05	2.03E+05	1.22E+05	1.24E+04
433 days @ 54 and 7 days @ 36 MW/mtU	2.29E+05	1.69E+05	1.09E+05	9.14E+03
439 days @ 54 and 1 day @ 36 MW/mtU	2.61E+05	1.89E+05	1.15E+05	9.22E+03

8.4.8.2 Spent Fuel Pool Cooling System

The spent fuel pool cooling system (SFPCS) pumps, HX, and the CCWS supply to the heat exchanger must be increased in size in order to maintain the SFP water temperatures within acceptable limits for personnel. These increases are due to the increased decay heat load due to the APUU thermal power increase and also due to the expected shorter fuel cycles which results in filling the spent fuel pool (SFP) at a faster rate with shorter times between refueling for the decay heat to decrease. An evaluation was performed which established the required heat exchanger size or UA (heat transfer coefficient x surface area) while maintaining the current reference plant spent fuel pool cooling pump capacity and component cooling water capability. This evaluation resulted in more than doubling the reference plant heat exchanger UA.

This heat exchanger capacity increase can be accomplished using a “plate” type heat exchanger, which can provide a large heat transfer area in a small space. The reference plant layout has been reviewed to assure that the required heat exchanger can be installed. There would, of course, would be local piping modifications required to connect both the spent fuel pool cooling system piping and component cooling water piping to the new heat exchangers.

8.5 References

[1] CN-SEE-02-104 “Replacement Steam Generator Program – RHR Cooldown Analysis for Callaway Unit 1”, December 2003.

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9 Determination of Power Uprate Roadmap (P. Rubiolo and E. Lahoda, WEC)

The results presented in the preceding sections are summarized in Table 9.1 and Table 9.2 of this section. These tables set the Roadmap adopted for performing the Power Ultra-Uprate. They provide the value of the upgrade required by the considered component of the primary and secondary systems and for the two different uprate levels used in the evaluation (25% and 50%). In these tables, a component having a value greater than 100% means that the Power Ultra-Uprate requires total replacement by a larger component. On the contrary a value less than 100% means that the component does not need to be replaced, but additional capability needs to be added in the system. For example, a value of 125% for the pressurizer means that this component needs to be replaced and upgraded by 25% with respect to the original capabilities. A value of 25 % for the Electrical Generator means that the original component is not replaced. However, a supplementary generator with 25 % of the original capacity needs to be added in parallel. Table 9.1 and Table 9.2 were used as input data for the economic evaluation described in Section 10.

Table 9.1 - Summary of the Primary System Equipment Changes Required for a Power Ultra-Uprate.

Primary System			
		Power Uprate	
Component	***Detail***	***25% Nominal***	***50% Nominal***
Core	First annular core + old non-used	125 + 50	150 + 50
	Core baffle (if required)	-	150
Reactor Vessel	Upper head of the vessel	-	-
	Control rod mechanism	-	-
Pressurizer	Pressurizer (all)	125	150
	Pressurizer safety valves	125	150
Steam Generator	Steam Generators (Delta 75 + new moisture separator)	125	150
	Steam & Feed-water lines pipes	-	150
	SG Safety, Isolation, Check and Dump valves	25	50
RCS Pumps	Pump Flow	125	150
	Motor Power	-	150
	Associated Cables	-	150
Auxiliary Systems	AFWS (Redesign for 2/4 success vs. 1/3)	4x62.5 (vs. 3x100)	4x75 vs. (3x100)
	SIS: 2 IHSI Pumps	200	200
	RHRS	-	-
	CCWS	-	-
	ESWS	-	-
	SFPCS: 2 SFP HXs (Plate & Frame HXs)	200	400
	Emergency Diesels	115	115
	Containment Fan Coolers	-	-
	Containment Spray System	-	-
Containment	Hatches	25	50
	Containment penetrations for outage	-	
Others	Control room	100	100
	Waste processing and disposal		

Table 9.2 - Summary of the Secondary System Equipment Changes Required for a Power Ultra-Uprate.

Secondary System			
		Power Uprate	
Component	***Detail***	***25% Nominal***	***50% Nominal***
Main Steam System		25	50
Turbine	HP turbine	25	50
	LP turbine	25	50
Condensate system		25	50
Main Feed Water System		25	50
Electrical Generator		25	50
UHS cooling towers		25	50
Buildings		25	50
Emergency Power Supply		25	50
Transmission		25	50

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10 Economic Evaluation of the Uprate (E.Lahoda, G. de Silva, WEC)

The economics of Ultra Uprating (UU) current generation nuclear power plants by 25% and 50% were determined. In addition, the potential savings resulting from using advanced fuel and steam generator technologies to uprate the design of a new, to-be-built, third generation plants like the AP1000, were also determined. Costs were generated using the Westinghouse cost template and normalized with the published cost of an AP1000 plant. In the case of the UU of a currently operating plant, the cost includes those associated with upgrading or replacing not only NSSS components, but all BOP components including electrical switch yards, breakers and transmission facilities. In addition, the UU of a current plant was charged a penalty for lost power during the period when the plant was out of production.

10.1 PWR Plant Candidates for Uprate Consideration-Baseline Plant

The four loop Westinghouse plants that are listed in Table 10.1 were identified by EPRI as near term candidates for this initial uprate feasibility assessment. The projected age of these plants by 2014 is shown. It was assumed that 2014 is the earliest deployment date of an Ultra-Uprate.

Table 10.1 - Candidate Westinghouse Four Loop Plants:

Capacity and Date of Initial Operation.

Plant	Capacity (MWe)	Initial Operations	Age in 2014 (years)
Callaway	1171	1984	30
Braidwood 1	1214	1989	25
Braidwood 2	1155	1989	25
Byron 1	1207	1985	29
Byron 2	1155	1987	27
Seabrook	1160	1990	24
Votgle 1	1215	1987	27
Votgle 2	1215	1989	25
Wolf Creek	1200	1985	29

Table 10.1 shows that the capacities for these units range from 1155 to 1215 MWe. This implies that after a 150% uprate, the total output of these plants could range from 1732 to 1822 MWe. For convenience, the nominal 50% uprate for the cost analysis is designated as 1800 MWe. A 25% uprate is designated as 1500 MWe.

10.2 Uprating and Renewal

The ultra uprate can be viewed as uprating a plant to get a much larger electrical generating capacity. However, it can also be viewed as a chance for renewal and improvement of the plant since, by the time the youngest of these plants could be uprated, they will be at least 25 years old. If the concept is broadened to take in the entire population of available PWRs, some plants could be more than 40 years old when they implement an uprate. For such plants, an ultra uprate, in addition to significantly increasing the power output, provides an opportunity for renewal of components and systems that have begun to age and as a chance to increase operating and safety margins where possible to lessen the stress on systems and components and thereby increase their longevity. However, given the plant specific nature of aging of structures, systems and components, this report covers only the items that must be replaced or modified to allow the uprate and does not consider the age of retained components. During the design of a specific uprate, known plant problems should be considered and resolved to achieve the greatest benefit from the uprate.

10.3 Ultra Uprate Capital Costs

The Westinghouse Cost Development Scheme (WCDS) was used to determine the overnight capital cost per KWe for several new plant configurations (AP1117, 600 MWe and 1800 MWe Plants). The overnight cost per KWe for the AP1117 was then normalized using the Reference [1] published overnight cost per KWe for the AP1117 plant. This normalization factor was then applied to the costs generated by the WCDS for the new 600 MWe and 1800 MWe plants as well as to the two levels of uprates, 1,500 MWe and 1800 MWe.

The power uprates modify the internals of the reactor and change the fuel design to allow either 25% or 50% more power to be generated. The details of the modifications to the nuclear and steam generation systems were discussed previously in this report. Figure 10.1 shows a schematic of the major components of a pressurized water reactor (PWR) design that would have to be changed. Order of magnitude cost estimates for PWR primary and secondary system modifications (components mainly inside the containment) were generated by Westinghouse. The Westinghouse cost projections were based on Company experience with the development, construction and fabrication of new plant designs and nuclear steam supply system (NSSS) modification upgrades. EPRI generated estimates for the balance of plant components (those outside the containment – see Appendix II). EPRI's input also considered the costs of replacement power and the length of time that the power plant would be off-line. The key assumptions for the ultra uprate cost estimates are summarized below and are followed by a comparison of the estimated overnight generation capital cost derived by Westinghouse and EPRI.

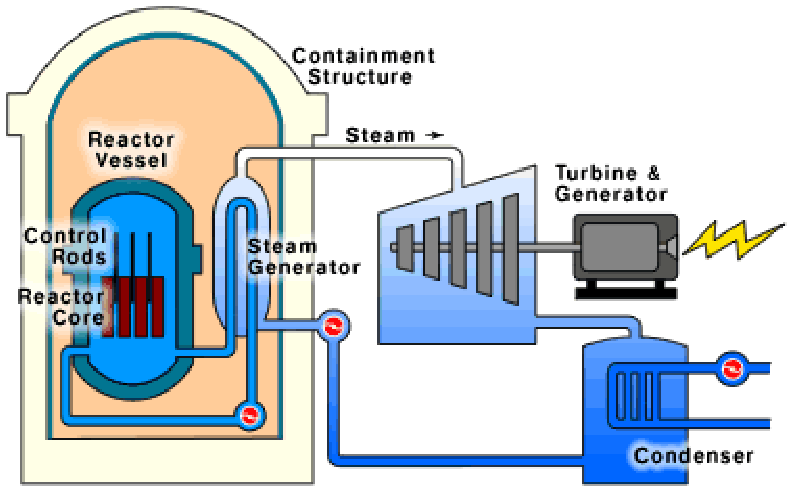

Figure 10.1 - Major Nuclear Components of a PWR System That Will Be Modified During an Ultra Uprate.

10.3.1 Cost Estimation Assumptions

Plant modifications required to support 150% output from an existing plant are quite different from constructing a new plant having 150% capacity in terms of costs, schedule and construction activities. Buildings and tanks near the existing unit must be moved, underground piping and cabling systems must be rerouted, and several major components in containment must be removed and replaced. These items include the steam generators (if not already replaced with upgraded designs), reactor coolant pumps (50% uprate only), and the pressurizer. Reactor internals may need to be replaced if only 12 foot cores can be accommodated and if 18 month cycles are desired. Most of these components can be replaced during outages preceding the transition outage with little or no impact on the schedule. With sufficient planning, much of the new BOP work can be done in parallel with operation of the old BOP. However, connection of the modified NSSS and the new additional BOP sections, major primary pipe re-routings, control room connections, and reactor startup and testing will require a relatively long transition outage. The length of the transition outage and associated replacement energy cost is a significant factor in the economics of the uprate as are the costs of removal of major components that are radioactive. For discussion purposes and for segregation of key cost contributors for the uprates, overnight costs associated with the actual plant modifications, labor, and hardware procurements are separated from the replacement power costs which can be site and outage duration specific. Plants which have replaced or are planning to replace steam generators or upgrade control system can derive some savings from coordinating the upgrade with planned plant improvements.

The EPRI report (see Appendix II) provides:

1. More detailed discussions on the major issues that need to be considered and factored into the uprate decision;
2. Identifies and discusses alternative approaches for implementing the uprate;
3. Provides BOP estimates of costs for 25 percent and 50 percent uprates; and,
4. Provides estimates for replacement power.

As noted in Appendix II, many components in the existing BOP have additional margins allowing some increase in loading. However, even those with the largest margins generally can accommodate no more than 20% uprates and many other components have much more limited margins. Often, turbines are sized to assure that the original plant capacity can be met. Margin is contained in their capability such that they can have higher output if the system can supply more steam of adequate quality. In addition, portions of the turbines can be replaced to achieve substantial uprates. However, none of the plants under consideration can accommodate a 25 to 50% uprate using the existing turbine generator systems. Accordingly, three alternatives are considered in Appendix II: A 25 % uprate and a 50% uprate implemented by adding a second smaller turbine generator system that increases the overall capacity; and a 50% uprate using a new 150% turbine generator system to entirely replace the original system. Table 9.1 and Table 9.2 summarize the plant modifications that were incorporated into the Westinghouse 25% and 50% ultra-uprate estimates.

With any uprate alternative, a number of basic assumptions were made about the activities that could be carried out during operation of the plant:

1. Construction could be performed adjacent to and within an operating plant, and within and adjacent to its security zone.
2. Trips of the operating plant from construction activity could be prevented.
3. Major rework of radiologically contaminated of components in controlled areas of the containment and in the auxiliary building could be performed.
4. Adjacent buildings, tanks and other structures could be relocated.
5. Interruption of the operation of existing underground pipes and cables, including circulating water for the operating plant, could be avoided by relocation or work arounds.
6. The plant circulating water capacity, including the capacity of the heat sink (e.g., cooling tower, river or lake), could be upgraded within current or minimally revised environmental permits.
7. Movement of heavy loads near the operating plant and underground facilities critical to operation could be effectively and safely managed.
8. Control of construction in the vicinity of energized 345 or 500 kV lines and substation equipment could be effectively and safely managed.

9. Restoration of rail facilities for transport of construction materials (including runaway train security issues) can be achieved.
10. The spent fuel pool will have the capacity for a minimum of two full cores (1 old and 1 new).
11. A dry fuel storage facility (assuming Yucca Mountain is not available for receiving spent fuel) will likely be necessary to assure adequate space for off-load of the entire old core and to have adequate space for at least a full core off-load of new fuel.
12. There is a reasonable remaining lifetime for significant systems, structures and components (e.g., reactor vessel embrittlement is not an issue) such that the useful life of the upgraded plant will be sufficient to achieve the required return on investment.
13. The cost of on-site storage or off-site transportation and disposal of the reactor head, core support structure components, steam generators, pressurizer, and reactor coolant pumps is acceptable.
14. The cost of capital for efforts that must be performed well in advance of the availability of the output of the uprated plant is not considered.
15. Development of a unified licensing basis for a plant with mixed old and new equipment, which may cause changes to the original licensing basis and affect original systems and components that remain in service, will be handled ahead of the first UU.

Some plant modifications or changes are desirable plant enhancements to support the uprate. These include prior conversion to a digital control room, and licensing and construction of dry fuel storage. The transition to a digital control room in advance of the uprate will allow more rapid transfer to and integration of the new and uprated equipment. Transition to a digital control room at the time of uprate could greatly complicate the effort and likely increase the length of the main outage. A dry fuel storage facility (assuming Yucca Mountain is not available for receiving spent fuel) will likely be necessary to assure adequate space for off-load of used fuel even without an uprate.

Both the Westinghouse and EPRI cost evaluations assume that as much of the existing equipment as possible will be retained and does not include consideration of replacing or upgrading equipment for purposes other than the uprate.

This order of magnitude cost assessment is based on the following key technical assumptions for the licensability of the uprated plant. The uprate cost estimates prepared by EPRI and Westinghouse both incorporated these key assumptions. The true upgrade costs could be quite different if these assumptions are not met:

1. The revised loss of coolant accident conditions (LOCA) will not cause an unacceptable increase in containment pressure. The pressure must not increase significantly and must remain inside the capability of the containment as it exists. An increase in pressure would require a reanalysis and possibly require modifications to the containment structure.

2. The revised mainsteam line break (MSLB) and LOCA conditions in containment will not cause a significant increase in peak temperature and pressure. A significant increase in MSLB or LOCA peak temperature and pressure could invalidate the environmental qualification of all electrical penetrations, safety-related cables, and, electrical and I&C equipment in containment. If this occurred, re-qualification testing would be required for the equipment and replacement of some or all of the equipment might be necessary.

The changes to the existing plants are expected to remain within these assumptions. Per initial Westinghouse assessments, the peak pressure and temperature conditions inside containment are within the currently licensed limits. However, the total thermal energy released during accidents will increase and additional heat removal capability must be implemented.

10.3.2 Program Uprate Levels and Transition Time Considerations

The uprate will be performed on an existing operating plant. Accordingly, the output from the plant will be lost for the period of the transition. Controlling the outage length is critical to assuring the economic viability of the ultra uprate. The initial concept is to perform as much construction and startup testing as possible prior to the main transition outage to assure that the transition outage is as short as possible. Assumptions for the Westinghouse and EPRI cost estimates are similar. Basic assumptions concerning the transition outage are:

1. Turbine plant work has progressed to the point where all equipment is start-up tested and live steam must be available to test further. All line flushing and tests not requiring steam have been performed.
2. The control system has been linked to a mockup control room and verified as being operable to the extent possible. The testing of the controls would be nearly complete; transition to the actual control room would be the next step. After the uprate, the "mock up" control room could be used as a backup control room, as a training facility or as an emergency support center.
3. All necessary measurements have been made in previous outages for reactor internals fit ups, reactor head, pumps, steam generators, piping and pressurizer and any necessary changes made in supports and restraints. The logistics and order of work and alternate paths should problems occur have been developed.
4. The simulator has been prepared and operators have been trained on the new system and any interim state procedures that are necessary.

In order to estimate the length of this outage, a listing of transition outage jobs was generated. The list of major work items is extensive and many activities will have to be completed under the constraints of radiological controls. Once all of the equipment is installed and system integrity has been demonstrated, startup testing and low power testing must occur. The 50% uprate or the increase of 600

MWe was selected as the power level for the uprate evaluation because it is the bounding case.

Major activities for transition outage once the shutdown begins are:

<u>Turbine Area</u>

- Connect circulating water lines to the new condenser
- Disconnect old feedwater system and connect new turbines feedwater system
- Disconnect old steam lines, connect new MSIV, new steam lines, rework safety relief valves

<u>Auxiliary Building</u>

- Uprates to long-term emergency cooling
- MSIV removal and replacement
- Disconnect safety relief valves, change orifices, reset, test, reinstall, reconnect to new steam lines
- Feedwater and steam line segment upgrade

<u>Containment</u>

- For plants not having an equipment hatch, cut an opening in the containment wall
- Head removal (move out of building as soon as possible)
- Fuel Off-load
- System flush and system decontamination
- Core barrel and support structure removal (if required)
- Core barrel and support structure removal from building (if required, interrupts all containment work due to dose)
- Installation of staging and temporary shielding
- Remove steam generators
- Remove primary piping
- Remove reactor coolant pumps
- Remove pressurizer relief valves (ship off site for resetting)
- Remove pressurizer
- Replace pressurizer
- Replace pressurizer heater cable and penetration
- Reinstall pressurizer relief valves
- Replace reactor pumps
- Reactor Pump 5 kV cable and power penetration replacement
- Upgrade containment coolers and cooling fans
- Containment fan cable penetration replacement
- Install higher capability primary piping supports and modify steam generator and RCP supports

- Install new primary piping modifications as needed
- Install new RCP, including new cables and electrical penetration modules
- Install new steam generators
- Install new core barrel and support structure (if removed)
- Restore containment and system integrity

An optimistic transition outage length is in the vicinity of 12 months for the 50% uprate. It might be possible to complete a 25% uprate in as little as 9 months due to a somewhat shorter testing and startup program. The outage length could be reduced due to some of the circumstances discussed below.

Performing the transition outage in less than 9 months will be difficult. The core structure, core, reactor head (not included for WEC estimate; cost $10 million), reactor circulation pumps, pressurizer and steam generators must be replaced and the main steam lines and new main steam isolation valves must be connected before startup testing of the new turbine is possible. All control room modifications must be completed as well. Experience with steam generator replacement on four loop PWRs in 1988 and 1989 indicate an outage length of five to six months is required for a much less complex operation.

Performance of some of the work will be necessary during outages that precede the final transition outage to minimize the later. Some work will be dictated by conflicts between the location of the new turbine and existing structures and underground components necessary for operation of the original reactor. This could include circulating water pipe, startup transformer power and control cables, fire piping, and various safety related and operationally important water tanks. During a number of outages before the final transition outage, relocation of components and structures affecting safety and operations will have to occur. The uprate efforts during these outages will have to be choreographed to not significantly impact outage length. In addition to the pre-transition outage efforts, savings may occur from moving activities from the final transition outage to earlier outages. However, the size and timing of pre-transition outage costs must be considered in that no payback on these expenditures would occur for four or more years.

Finally, some plants may have recently replaced such items as steam generators. In this case, the cost and time associated with this replacement would not be included and would decrease the length of the final transition outage.

10.3.3 Replacement Power and Fuel Considerations

Assuming that the outage is taken from the beginning of the fall through the end of the following spring and that contracts are in place for the replacement power, EPRI estimated the replacement power cost to range from $500,000 to $1,000,000 per day, which equates to $137 to $273 million for a nine month outage and $183 to $364 million for the 12 month outage. The best estimate of the outage cost is $225 million for a 12 months final transition outage. The final normalized overnight costs for both the 25% and 50% uprates assume a $71 million fuel cost. This cost consists of $54 million estimated for a new core load plus $17 million stranded cost for the previous core that is discarded when the uprated fuel is installed.

Table 10.2 shows the cost break downs for the 25 % and 50 % uprates that were estimated by Westinghouse with the assumptions listed in Table 9.1 and Table 9.2 and other considerations identified by EPRI in Appendix II. With these assumptions, normalized total overnight capital costs of $2050 per KWE and $1381 per KWE were calculated, respectively, for the 25% and 50% uprates. These normalized overnight cost do not include the replacement power and fuel costs. When replacement power and fuel replacement costs were factored into the final normalized cost entries given in Table 10.2, the Westinghouse normalized total overnight cost estimates were increased to $2923 and $1817 per KWe for the 25% and 50% uprate options. Both, the 25 percent and 50 percent outage costs estimates given in Table 10.2 assume a 12 month outage for simplicity and conservatism.

10.3.4 Comparison of WEC and EPRI Ultra Uprate Costs Estimates

Appendix II provides a detailed discussion of the EPRI cost estimates for the 25% and 50% ultra uprates. The EPRI input from Appendix II concluded that there is no significant advantage to implementing a 25% uprate. This input also noted that the installation of an 1800 MW(e) turbine/generator and abandonment of the existing system is neither cost effective nor practical with respect to transmission circuit breaker limitations. Accordingly, the bulk of this assessment is based on a 50% uprate using a 600 MWe turbine/generator in parallel with the existing 1200 MWe system.

The detailed EPRI overnight costs for a 50 percent uprate are summarized in Table 10.3. This table shows the EPRI high and low cost values in the cost estimate. Midpoint values were calculated from the EPRI low and high cost values for comparison with the Westinghouse cost estimates for the 50% uprate. The EPRI costs are subtotaled in Table 10.3 as Nuclear System plus SG Costs, Safety System Upgrade Costs, Secondary Plant Uprate Implementation Costs and Ultra Uprate Unique Costs. Table 10.3 shows that the Ultra Uprate unique costs include the cost of replacement power for the transition outage, the penalty for a 12 month instead of current 18 month operating cycle, outage preparations, radioactive equipment removal and storage, construction under nuclear security and outage planner. This cost subtotal ranged from $52 million to $719 million. These costs, with the exception of the 12 month cycle penalty were factored into the Westinghouse overnight cost/KWE given in Table 10.2.

The EPRI final overnight costs are shown at the bottom of Table 10.3. Depending on cost assumptions, total overnight cost estimates for the EPRI 50% power uprate ranged from $2046 per KWE to $3880 per KWE. The midpoint value was estimated to be $2963 per KWE.

Table 10.2 - Westinghouse Estimates of 25 % and 50 % Ultra Uprate Costs.

Account	Ultra Uprate Power (MW(e))	300	600
	Ultra Uprate Level	25%	50%
211	Yardwork	$ 1,113,542.15	$ 2,227,084
212	Reactor Containment Building	$ -	$ -
213	Turbine-Generator Bldg	$ 12,521,896.95	$ 19,785,632
215	Annex & Auxiliary Building	$ -	$ -
215A	Annex Building	$ -	$ -
215B	Auxiliary Building	$ -	$ -
216	Radwaste Building	$ -	$ 444,841
218A	Diesel Generator Building	$ -	$ -
	Containment hatch mods	$ 15,000,000.00	$ 30,000,000
21	Structures & Improvements	$ 28,635,439.10	$ 52,457,557
221	Reactor Equipment	$ -	$ -
222	Main Heat Transfer System	$ 62,455,680.55	$ 183,370,078
223	Passive Safety System	$ -	$ -
224	Radwaste Processing Sys.	$ -	$ 7,196,862
225	Fuel Handling and Storage	$ 6,593,151.69	$ 13,186,303
226	Reactor Auxiliary Systems	$ -	$ 7,446,068
227	Instrumentation & Control	$ -	$ 61,723,619
228	Reactor Plant Miscellaneous Items	$ 7,757,334.98	$ 12,257,230
22	Reactor Plant Equipment	$ 76,806,167.23	$ 285,180,160
231	Turbine-Generator Equip.	$ 47,584,074.24	$ 81,708,083
233	Condensing Systems	$ 14,715,091.46	$ 23,090,454
234	Feedwater System	$ 6,575,763.49	$ 9,966,994
235	Other Turbine Plant Sys.	$ 1,715,930.46	$ 2,711,312
236	Turbine Plant I&C	$ 6,310.27	$ 9,980
237	Turbine Plant Miscellaneous Items	$ 6,009,379.31	$ 9,495,316
23	Turbine Plant Equipment	$ 76,606,549.22	$ 126,982,138
242	EPE Station Service	$ 18,323,891.65	$ 24,011,507
244	Protective Equipment	$ 7,961,884.05	$ 10,433,200
24	Electric Plant Equipment	$ 26,285,775.70	$ 34,444,707

Table 10.2 (Cont.) - Westinghouse Estimates of 25 % and 50 % Ultra Uprate Costs.

Account	Uprate Power (MW(e)) Ultra Uprate Level	300 25%		600 50%	
251	Transportation & Lifting Equip.	$	-	$	11,304,906
252	Air & Water System	$	-	$	-
253	Communication System	$	-	$	-
254	Furn, Fixtures & Lab Equip	$	-	$	-
255	Waste Water Treatment Equip	$	1,284,096.98	$	1,475,040
25	Miscellaneous Plant Equip.	$	1,284,096.98	$	12,779,946
261	Heat Rejection Sys. Struct.	$	24,960,943.65	$	32,936,163
262	Heat Rejection Sys. Equip.	$	1,330,164.78	$	1,755,163
26	Main Cond. Heat Reject Sys	$	26,291,108.43	$	34,691,326
2	Total Direct Costs Summary	$	235,909,136.66	$	546,535,834
	Non Allocated Equipment Shipping Co	$	4,957,483.27	$	8,053,455
	Modularization Cost Reduction	$	-	$	-
	Premium Time Labor Adder	$	9,413,151.43	$	15,291,710
	Unscheduled Direct Overtime Labor A	$	4,235,918.24	$	6,881,269
2	Total Direct Costs	$	254,515,689.60	$	576,762,268
	$ or MH Per Net KWe	$	848.39	$	961
911	Temporary Construction Facilities	$	23,383,455.51	$	37,986,536
912	Construction Tools & Equipment	$	23,537,232.15	$	38,236,346
913	Payroll Insurance & Taxes	$	17,362,836.76	$	28,206,012
914	Permits, Insurance & Local Taxes	$	1,490,186.18	$	2,420,815
91	Construction Services	$	65,773,710.60	$	106,849,708
921	Home Office Engineering	$	30,141,300.05	$	48,964,686
922	Home Office QA/QC	$	978,125.69	$	1,588,970
923	Home Office Construction Manageme	$	3,399,760.32	$	5,522,927
92	Eng. & Home Office Services.	$	34,519,186.06	$	56,076,583
931	Field Office Expenses	$	2,399,060.70	$	3,897,286
932	Field Job Supervision	$	32,542,096.62	$	52,864,792
933	Field QA/QC	$	5,980,143.04	$	9,714,771
934	Plant Start-up & Testing	$	3,652,974.27	$	5,934,274
93	Field Sup & Field Off Services	$	44,574,274.63	$	72,411,123

Table 10.2 - Westinghouse Estimates of 25 % and 50 % Ultra Uprate Costs.

Account	Ultra Uprate Level		25%		50%
	Direct Labor Premium Time Pay Taxe	$	720,106.37	$	1,169,816
	Construction Labor Premium Time La	$	2,269,591.33	$	3,686,962
	Unscheduled Indirect Overtime Labor	$	948,737.72	$	1,541,229
9	TOTAL INDIRECT COSTS	$	148,805,606.72	$	241,735,421
	$ Per Net KWe	$	496.02	$	403
2+9	BASE CONSTRUCTION COSTS (TP	$	403,321,296.32	$	818,497,690
	$ Per Net KWe	$	1,344.40	$	1,364
941	Management & Integration	$	4,533,287.39	$	7,364,347
942	Taxes & Insurance	$	3,307,131.15	$	6,706,971
943	Spare Parts & Initial Supplies	$	6,156,079.91	$	12,312,160
944	Staff Training & Startup	$	32,456,850.03	$	52,726,308
945	General & Administrative	$	5,548,520.61	$	9,013,598
946	Capital Equipment	$	9,288,638.56	$	18,577,277
	Allocated Non-Recurring	$	2,296,641.40	$	4,593,283
	Land and Land Rights	$	2,551,823.78	$	5,103,648
	Replacement Power	$	224,694,000.00	$	-
94	Owner's Cost	$	290,832,972.83	$	116,397,592
	TOTAL OVERNIGHT COSTS	$	694,154,269	$	934,895,281
	$ Per Net KWe	$	2,314	$	1,558
	Normalized uprate Overnight Cost	$	2,050	$	1,381
	Replacement Power	$	224,694,000	$	224,694,000
	Fuel Cost	$	71,000,000	$	71,000,000
	Total Overnigt Costs w/RP	$	989,848,269	$	1,230,589,281
	$ Per Net KWe	$	3,299	$	2,051
	$Per Net KWE normalized to Ap1117	$	2,923	$	1,817

Table 10.3 - EPRI 50% Ultra Uprate Cost Breakdowns.

	Low	High	Midpoint
RCPS	$ 70,000,000	$ 90,000,000	$ 80,000,000
Replace RCP cables, RCP and pressurizer electrical penetrations	$ 6,000,000	$ 12,000,000	$ 9,000,000
Pressurizer,SGS, reactor head	$ 450,000,000	$ 600,000,000	$ 525,000,000
Replace MS Piping , upgrade Relief valves	$ 20,000,000	$ 40,000,000	$ 30,000,000
Replace MSIV	$ 10,000,000	$ 16,000,000	$ 13,000,000
Upgrade Pipe Supports for Steam and Feed	$ 5,000,000	$ 10,000,000	$ 7,500,000
Increase Auxfeed Capacity	$ 5,000,000	$ 10,000,000	$ 7,500,000
Add common condensate surge tank	$ 8,000,000	$ 12,000,000	$ 10,000,000
New Mainsteam Isolation Valves	$ 12,000,000	$ 24,000,000	$ 18,000,000
MSR upgrade			
Nuclear System & SG Costs	$ 586,000,000	$ 814,000,000	$ 700,000,000
Environmental Qualification	$ 500,000	$ 5,000,000	$ 2,750,000
Additional Emergency Diesel & Switch gear	$ 10,000,000	$ 25,000,000	$ 17,500,000
Ultimate Heat Sink Capacity increase	$ 5,000,000	$ 10,000,000	$ 7,500,000
Intermediate Pressure Injection Upgrade	$ 10,000,000	$ 20,000,000	$ 15,000,000
Low Pressure Injection Upgrade	$ 12,000,000	$ 30,000,000	$ 21,000,000
Containment Coolers Upgrade	$ 3,000,000	$ 6,000,000	$ 4,500,000
rerack and rearrange fuel pool and upgrade fuel pool cooling	$ 12,000,000	$ 25,000,000	$ 18,500,000
Safety System Upgrade Costs	$ 52,500,000	$ 121,000,000	$ 86,750,000
Relocation of Existing Circulation Water Lines and Underground Equip	$ 10,000,000	$ 20,000,000	$ 15,000,000
New turbine/generator	$ 300,000,000	$ 600,000,000	$ 450,000,000
Added intake structure,circwater pipe to new turbine			
Transmision Substation, bus Extension			
Medium Voltage Substation Upgrade including MCS and Load center	$ 20,000,000	$ 40,000,000	$ 30,000,000
Control Room Integration	$ 7,000,000	$ 14,000,000	$ 10,500,000
Secondary plant Uprate Implement Costs	$ 337,000,000	$ 674,000,000	$ 505,500,000
Transition Outage length	$ 137,000,000	$ 365,000,000	$ 251,000,000
Penalty for 12 month cycle	$ 63,000,000	$ 239,000,000	$ 151,000,000
Outage Preps	$ 25,000,000	$ 50,000,000	$ 37,500,000
Radioactive requipment removal and storage	$ 10,000,000	$ 20,000,000	$ 15,000,000
Construction Under Nuclear Security	$ 5,000,000	$ 20,000,000	$ 12,500,000
Outage Planner	$ 12,000,000	$ 25,000,000	$ 18,500,000
UlraUprate Unique Costs	$ 252,000,000	$ 719,000,000	$ 485,500,000
Total OverNight Cost	$ 1,227,500,000	$ 2,328,000,000	$ 1,777,750,000
Total Overnight Cost/KW	$ 2,046	$ 3,880	$ 2,963

In order to compare the EPRI and Westinghouse estimates Table 10.4 was generated that provides a more succinct grouping of major contributors for the EPRI capital cost estimate. This table shows that the total capital cost for a 50% uprate could range from $1.2 billion to $2.3 billion. The major items for each category are:

1) **Nuclear and Steam System** – Cost $586 million-$814million with a midpoint price of $700 million which includes new pressurizer, new RCPS, SGS , MSIVS, MS piping supports, new main steam piping

2) **Secondary Plant** – additional turbine, circwater routing electrical switch yard. Table 10.4 shows cost for this segment of the uprate ranged from $337 million to $674 million with a midpoint price of $505 million.

3) **Safety System** – upgrade Auxiliary systems like emergency diesel, containment coolers, fuel pool cooling. Table 10.5 shows this cost adder ranged from $53 million to $121 million with a midpoint value of $ 87 million.

4) **UltraUprate Unique Modifications** – lost generation during uprate outages, reduction in capacity factor to implement 12 month refueling cycle)

Table 10.4 - Tabulation of Summary Capital Costs for EPRI 50% Ultra Uprate (Millions).

Cost Area	Low	High	Midpoint
Ultra Uprate Unique	$252	$719	$485
Secondary Plant	$337	$674	$505.5
Nuclear and Steam System	$586	$814	$700
Safety Systems	$53	$121	$87
Total Overnight Capital Cost	$1228	$2328	$1778
Total Cost /KWE (dollars)	$2,046	$3,880	$2,963

The greatest drivers in the EPRI cost estimate for the uprate beyond the normal costs of construction were identified as:

- Costs unique to Ultra Uprate: ($252 to $719 million). The values for contributors in this category are detailed in Table 10.5. The two largest drivers in this category for the EPRI cost are:
    - Preparatory and transition outages ($307 million midpoint value) and
    - Lost revenue of a 12 month refueling cycle over 20 years of operation ($151million).
- Costs associated with removal of Reactor and Steam System equipment (head, core support, reactor coolant pumps, pressurizer, steam piping): $100 to $180 million.
- Cost of rearranging and relocating existing piping and equipment to allow construction: $15 to $30 million.

The summation of the above EPRI costs range from $367 to $929 million, which put the ultra uprate at a distinct disadvantage with comparison to new construction. Deducting these costs unique to Ultra Uprate from the low and high summary costs yields, a lower estimate bound of $830 million and a high estimate bound of $1.37 billion, which are slightly favorable in comparison to building a new unit.

Table 10.5 - Contributors to Uprate Unique Costs According To EPRI.

Issue	Comment	Low Value	High Value
Transition Outage Length	The length of the transition outage must be tightly controlled. An optimistic transition outage is approximately 12 months for a 50% uprate. A 25% uprate may take as little as 9 months due to somewhat more limited testing and startup.	$137[9]	$365[10]
12-Month Refueling Cycle	Because of higher energy density, the refueling cycle after uprate will be 12 months. The present value cost of the more frequent outages is presented	$63[11]	$239
Preparatory Outage 1 Length	30 additional days for underground piping rearrangements	$15	$30
Preparatory Outage 2 Length	20 additional days for prep work	$10	$20
Radioactive work logistics	A large volume of radioactive equipment must be removed and stored.	$10	$20
Construction will be under nuclear plant security controls	Much of the construction will be inside operating plant boundaries and post- 9/11 security requirements will apply	$5	$20
Outage Planning	To assure shortest possible outage, additional outage planners will be needed for a period of 3 or more years	$12	$25
Total		$252	$719

These Ultra-Uprate unique costs would not be incurred for either a new nuclear plant or a plant with any other fuel. The cost of the lengths of the transition outage and pre-transition outages are critical. Any reduction in the length of these outages will significantly aid the case for ultra uprates.

The outage cost assumed for the Westinghouse Total Overnight cost was $225 million which is about $26 million ($43/KWE) lower than the midpoint value used for the EPRI estimate. However, a more significant escalator for the EPRI

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[9] Low outage costs are based on $500,000/ day replacement cost
[10] High outage costs are based on $1,000,000/day replacement cost
[11] Present value high and low costs are explained in Section 3

overnight cost was the reduction in outage capacity which according to Table 10.5 could range widely from $63 million to $239 million. A midpoint cost of $151 million was used in Table 10.3 and included in the Total Overnight Cost for the 50% EPRI uprate but not in the Westinghouse estimate. The reduction of capacity factor from having to implement a 12-month refueling cycle has a significant effect on the total overnight capital cost (~$252/KWE). The 12-month refueling cycle effect cost shown in Table 10.5 and Table 10.6 according to Appendix II are the present value costs for a 20 year period. The key factors in these calculations are the cost of money, the inflation rate, and the cost of replacement power. Methods to reduce this penalty including longer rods or higher density fuel could also be looked at to reduce or eliminate it.

Due to the difficulties with accurately projecting the capacity factor cost, Westinghouse did not include a capacity penalty in the final cost shown in Table 10.2. For discussion purposes, inclusion of a $151 million capacity cost raises the Westinghouse normalized overnight cost for a 50% uprate by $252 per KWE to a value of $2069 per KWE. This value is close to the low estimate of total overnight cost estimated by EPRI.

Another significant difference in cost assumptions is in the assumed cost for the steam generators plus the pressurizer plus the reactor head. The midpoint EPRI cost estimate for these components was $572 million. The Westinghouse total cost for these items plus hatch modifications was $141 million. This total includes the following cost contributors: pressurizer and heater ($8.6 million), reactor head with installation ($10 million), steam generator replacement including installation ($92 million) and hatch modifications ($30 million). The difference in the cost input for these items account for approximately $431 million (~$719/KWE) of the higher total cost for the EPRI estimate.

It should be recognized that significant uprate cost allocations could be deducted if coordinated with ongoing and planned steam generator replacements. Many plants have replaced or plan to replace steam generators due to corrosion degradation issues. The new replacement steam generators have sufficient heat transfer margin to support up to a 50% uprate. In addition, outage time for SG replacement for purposes other than an uprate can be deducted from the uprate cost. The discussion of steam generator replacement considerations identifies possible synergies that can be derived by ongoing plant renewal that should reduce uprate costs.

To allow an ultra-uprate to proceed, a number of generic and plant specific issues must be considered and resolved. Table 10.6 lists issues of high importance that must be considered and resolved but that are outside the scope of the Westinghouse/EPRI uprate cost estimates. These considerations are listed for inclusion in future evaluations of this nature.

Table 10.6 - High Importance Issues to Be Resolved Outside The Scope of This Uprate Cost Estimate.

Issue	Resolution Statement	Comment	Importance (10 high)
Licensing basis must be resolved (what licensing basis applies to old and uprated sections of the plant)	Must be resolved with NRC prior to start of design of changes		10
The safety analysis report for the uprate must be prepared and accepted by the NRC		Safety analysis must be accepted before significant construction activities begin	10
Permits for additional cooling water and need for installation of cooling towers	Must be resolved with state and federal governments	Common to any new plant construction.	10
Additional transmission may be needed to allow power transfer	All plants will need additional transmission lines to cover the contingency of loss of one line. Additional transmission may be necessary to transfer power under local low load conditions	Plant specific issue. Costs will vary significantly by location.	10
Aging of retained structures, systems, and components	Retained SSCs should be reviewed to determine if refurbishment or replacement is prudent	Plant is likely to be 25 or more years old at time of uprate	8
Dry fuel storage is assumed to be licensed for the site	To allow transfer of old core from reactor and have sufficient core space in the fuel pool for the new fuel, old fuel will have to be transferred to dry storage	Most plants are likely to have dry fuel storage plans implemented by time of uprate.	8
The Control Room is assumed to have been converted to digital based	Implementation of uprate requires a digital control room	Plants will have been converted to digital control by time of implementation of uprates	8

10.3.5 New Plant Cost Estimates

The nuclear industry acceptance of the Ultra Uprate options depends upon the competitiveness with building a new plant of equivalent or higher capacities. Cost estimate were prepared for new plants ranging from 600 MWE, which is equivalent to a 50 % upgrade, and AP1117, 1200 MWE, and 1800 MWE plants. The industry convention of reporting overnight cost per KWE was selected for all the cost comparisons. Reference [1] provided a recent estimate of AP1117 cost that was used to develop a normalizing factor for the Westinghouse cost estimates for the new plant and uprate options. The use of the same methodology provides consistency and a common basis for the cost estimates for the new plant and uprates.

Table 10.7 shows that the overnight costs for a new AP1117 plant was normalized to match the $1310 per KWE cost reported by Reference [1]. With this convention, Westinghouse estimated prices were $1593 per KWE for the 600 MWE plant, $1282 per KWE for the 1200 MWE and $1135 per KWE for the 1800 MWE plant. The overnight cost listed in Table 10.7 includes all component and new plant fabrication costs except the initial fuel loading cost. Since the AP1117 cost estimate was normalized and the normalization factor was used in all cost estimates, there is no large difference due to not including fuel cost for the new plant estimates. Replacement power cost and 12 month cycle load effects are major considerations for the uprate options. These costs do not come into play for the new plant construction options that are shown in Table 10.7.

The $1593 per KWE total overnight cost estimated for a new 600 MWE plant is comparable but slightly lower than the $1817 per KWE estimated for the 50% Ultra Uprate by Westinghouse. Improvement in uprate unique costs by deduction of steam generator cost and outage length, if replacement is required for corrosion or equipment aging replacement, would further shrink the cost differential.

The other positive factor for the Ultra Uprate which does not show up in this simple cost comparison is the anticipated shorter construction time for the uprate compared to licensing and construction of a new plant on a new site. This is especially important for plants which have capacity shortages and expect rapid demand growth.

Table 10.7 - Comparisons of New Plant Construction Costs for AP1117, 600 MWE, 1200 MWE, 1800 MWE.

Acc	Description	AP1117	600.00	1200	1800
211	Yardwork	8,292,177.21	4,454,168.60	8,908,337.20	13,362,505.79
212	Reactor Containment Building	100,214,622.69	66,496,046.72	105,069,247.97	137,308,004.25
213	Turbine-Generator Bldg	29,818,458.73	19,785,631.79	31,262,932.99	40,855,445.52
215	Annex & Auxiliary Building	4,396,509.16	2,917,243.72	4,609,486.11	6,023,830.47
215A	Annex Building	15,896,138.99	10,547,666.33	16,666,184.28	21,779,926.54
215B	Auxiliary Building	47,898,259.57	31,782,237.17	50,218,560.69	65,627,293.22
216	Radwaste Building	3,352,046.97	2,224,205.07	3,514,427.79	4,592,771.67
218A	Diesel Generator Building	1,878,110.26	1,246,194.46	1,969,090.22	2,573,272.89
21	**Structures & Improvements**	211,746,323.58	139,453,393.85	222,218,267.24	292,123,050.36
221	Reactor Equipment	88,161,146.61	47,356,032.20	94,712,064.40	142,068,096.60
222	Main Heat Transfer System	176,696,272.01	117,975,312.65	185,123,108.50	240,946,128.52
223	Passive Safety System	56,008,423.91	37,163,626.15	58,721,599.92	76,739,349.02
224	Radwaste Processing Sys.	10,846,221.21	7,196,862.22	11,371,636.94	14,860,835.15
225	Fuel Handling and Storage	24,548,501.46	13,186,303.38	26,372,606.76	39,558,910.15
226	Reactor Auxiliary Systems	10,811,056.98	7,446,068.08	11,286,128.74	14,394,605.11
227	Instrumentation & Control	101,508,839.47	66,731,940.65	106,600,823.82	140,934,999.14
228	Reactor Plant Miscellaneous Items	18,472,582.38	12,257,230.21	19,367,436.48	25,310,013.17
22	**Reactor Plant Equipment**	487,053,044.03	309,313,375.55	513,555,405.57	694,812,936.87
231	Turbine-Generator Equip.	132,674,824.17	81,708,082.93	140,303,471.76	192,495,064.88
233	Condensing Systems	34,583,481.61	23,090,453.52	36,232,805.28	47,158,640.70
234	Feedwater System	14,471,226.31	9,966,993.66	15,107,137.40	19,268,013.18
235	Other Turbine Plant Sys.	4,086,154.18	2,711,311.90	4,284,096.82	5,598,600.88
236	Turbine Plant I&C	15,078.17	9,980.02	15,814.68	20,719.90
237	Turbine Plant Miscellaneous Items	14,310,166.39	9,495,315.83	15,003,383.54	19,606,922.97
23	**Turbine Plant Equipment**	200,140,930.83	126,982,137.85	210,946,709.49	284,147,962.51
242	EPE Station Service	30,597,163.22	24,011,506.75	31,464,520.06	36,855,024.37
244	Protective Equipment	13,294,723.12	10,433,200.35	13,671,596.91	16,013,816.09
24	**Electric Plant Equipment**	43,891,886.34	34,444,707.09	45,136,116.97	52,868,840.46

Table 10.7 (continued) - Comparisons of New Plant Construction Costs for AP1117, 600 MWE, 1200 MWE, 1800 MWE

Acc	Description	AP1117	600.00	1200	1800
251	Transportation & Lifting Equip.	12,801,101.19	11,304,905.76	12,985,926.65	14,082,870.87
252	Air & Water System	30,537,576.82	26,968,338.33	30,978,485.87	33,595,293.45
253	Communication System	3,359,616.35	2,966,943.68	3,408,123.32	3,696,013.53
254	Furn, Fixtures & Lab Equip	2,858,827.84	2,524,687.44	2,900,104.30	3,145,081.25
255	Waste Water Treatment Equip	1,670,260.49	1,475,040.09	1,694,376.12	1,837,503.07
25	Miscellaneous Plant Equip.	51,227,382.70	45,239,915.28	51,967,016.27	56,356,762.17
261	Heat Rejection Sys. Struct.	42,231,233.56	32,936,162.61	43,459,527.11	51,111,838.16
262	Heat Rejection Sys. Equip.	2,250,495.82	1,755,162.95	2,315,951.39	2,723,741.85
26	Main Cond. Heat Reject Sys	44,481,729.38	34,691,325.55	45,775,478.50	53,835,580.01
2	Total Direct Costs Summary	1,038,541,296.86	690,124,855.18	1,089,598,994.04	1,434,145,132.37
	Non Allocated Equipment Shippin	12,442,670.49	8,053,455.33	13,082,876.78	17,376,693.16
	Modularization Cost Reduction	-	-	-	-
	Premium Time Labor Adder	23,625,847.06	15,291,709.62	24,841,455.56	32,994,452.07
	Unscheduled Direct Overtime Lab	10,631,631.41	6,881,269.48	11,178,655.25	14,847,503.77
2	**Total Direct Costs**	1,085,241,445.81	720,351,289.61	1,138,701,981.63	1,499,363,781.38
	$ or MH Per Net KWe	971.57	1,200.59	948.92	832.98
911	Temporary Construction Facilities	58,689,584.21	37,986,535.55	61,709,309.06	81,962,380.81
912	Construction Tools & Equipment	59,075,544.58	38,236,346.44	62,115,128.05	82,501,390.09
913	Payroll Insurance & Taxes	43,578,575.00	28,206,011.53	45,820,800.91	60,859,244.58
914	Permits, Insurance & Local Taxes	3,740,183.19	2,420,814.59	3,932,624.90	5,223,317.27
91	Construction Services	165,083,886.98	106,849,708.11	173,577,862.92	230,546,332.75
921	Home Office Engineering	75,650,939.03	48,964,686.38	79,543,367.70	105,649,599.61
922	Home Office QA/QC	2,454,974.64	1,588,969.88	2,581,289.18	3,428,471.49
923	Home Office Construction Manag	8,532,978.35	5,522,926.94	8,972,021.28	11,916,649.79
92	Eng. & Home Office Services.	86,638,892.02	56,076,583.20	91,096,678.17	120,994,720.90
931	Field Office Expenses	6,021,345.94	3,897,285.60	6,331,159.14	8,409,053.42
932	Field Job Supervision	81,676,641.80	52,864,791.92	85,879,107.84	114,064,737.52
933	Field QA/QC	15,009,420.17	9,714,771.04	15,781,692.11	20,961,263.03
934	Plant Start-up & Testing	9,168,514.07	5,934,274.21	9,640,256.89	12,804,201.16
93	Field Sup & Field Off Services	111,875,921.98	72,411,122.77	117,632,215.99	156,239,255.13
9	Total Indirect Cost Summary	363,598,700.98	235,337,414.08	382,306,757.07	507,780,308.78
	Direct Labor Premium Time Pay T	1,807,378.01	1,169,816.24	1,900,372.09	2,524,076.57
	Construction Labor Premium Time	5,696,393.83	3,686,962.00	5,989,487.44	7,955,244.64
	Unscheduled Indirect Overtime La	2,381,214.46	1,541,228.98	2,503,733.86	3,325,462.41
9	**TOTAL INDIRECT COSTS**	373,483,687.28	241,735,421.29	392,700,350.46	521,585,092.41
	$ Per Net KWe	334.36	402.89	327.25	289.77
2+9	**BASE CONSTRUCTION COSTS**	1,458,725,133.09	962,086,710.90	1,531,402,332.09	2,020,948,873.78
	$ Per Net KWe	1,305.93	1,603.48	1,276.17	1,122.75
941	Management & Integration	11,377,991.25	7,364,347.10	11,963,417.16	15,889,825.50
942	Taxes & Insurance	11,977,485.87	7,829,854.26	12,588,190.70	16,722,723.21
943	Spare Parts & Initial Supplies	22,921,137.52	12,312,159.81	24,624,319.63	36,936,479.44
944	Staff Training & Startup	81,462,683.39	52,726,308.43	85,654,140.74	113,765,935.94
945	General & Administrative	13,926,101.20	9,013,598.33	14,642,633.68	19,448,364.22
946	Capital Equipment	34,584,697.55	18,577,277.11	37,154,554.22	55,731,831.33
	Allocated Non-Recurring	8,551,161.48	4,593,282.80	9,186,565.60	13,779,848.41
	Land and Land Rights	9,501,290.54	5,103,647.56	10,207,295.12	15,310,942.67
	Replacement Power	-	-	-	-
94	**Owner's Cost**	194,302,548.79	117,520,475.40	206,021,116.85	287,585,950.72
	TOTAL OVERNIGHT COSTS	1,653,027,681.89	1,079,607,186.30	1,737,423,448.95	2,308,534,824.51
	$ Per Net KWe	1,479.88	1,799.35	1,447.85	1,282.52
	Normalized $ per Net Kwe	1,310.58	1,593.50	1,282.22	1,135.80

10.4 Summary of the Economic Evaluation

The industry convention of reporting overnight cost per KWE was selected for comparing cost estimates for several new plant and upgrade options. Reference [1] provided a recent estimate of AP1117 cost that was used to develop a normalizing factor for the Westinghouse cost estimates. The use of the same methodology provides consistency and a common basis for comparing all cost estimates.

Ultra Uprate cost estimates were prepared by Westinghouse for 25% and 50% power increases to a 1200 MWE existing PWR design nuclear power plant. Normalized total overnight cost of $2050 per KWE and $1381 per KWE were calculated, respectively, for the 25% and 50% uprates. These first cost estimates include only uprate required plant modifications. This set of overnight costs do not include other uprate costs such as lost generation cost during outage implementation of the plant modifications, uprate fueling cost and 12 month load factor penalty. The inclusion of these cost adders, depending on the cost assumptions, yielded the higher total overnight costs as estimated by EPRI to range from $2046 per KWE to $3880 per KWE for a 50 % uprate. The EPRI midpoint total overnight cost was $2963 per KWE.

The ultimate attractiveness of Ultra Uprate options to the nuclear industry depends on its relative competitiveness with building a new plant of equivalent or higher capacities. Cost estimate were prepared for new plants ranging from 600 MWE, with equivalent power output to a 50% upgrade, and AP1117, 1200 MWE, and 1800 MWE plants. Westinghouse predicted that the construction of a new 600 MWE plant would have an overnight cost of $1593 per KWE. This is comparable but slightly lower than the $1817 per KWE estimated for the 50% Ultra Uprate by Westinghouse. Improvement in the uprate unique costs by the deduction of already replaced steam generator costs and reduction in the outage length, if they have been already replaced due to corrosion or equipment aging replacements, would further shrink the cost differential.

A positive factor for the Ultra Uprate which does not show up in the simple cost comparison is an expected shorter construction time for the uprate compared to licensing and construction of a new plant on a new site. This could be especially important for plants that have capacity shortages and expect rapid demand growth.

10.5 References

[1] Paulson, Keith, “Future Commercial Nuclear Power Expansion in the US”, World Nuclear Association Annual Symposium , 4-6 Spetmeber2002- London

11 Conclusions of the Power Ultra-Uprate Evaluation

The purpose of this project was to assess the feasibility of a Ppower Ultra-Uprate on an existing nuclear plant. The study determined the technical and design limitations of the current components, both inside and outside the containment. Costs for modified pieces of equipment and for change-out and disposal of the replaced equipment were evaluated. These costs were then used to develop capital, fuel and O&M cost estimates for the Power Ultra-Uprate plant. The cost evaluation indicates that the largest single cost components are the replacement of power (during the final transition outage required for the uprate) and the new fuel loading. Based on these results, the study concluded that for a “standard” 4-loop plant, the proposed power uprate is likely more expensive than the cost per Kw electric installed of a new plant when large capacity uprates are considered (>25%). However, the concept of the Power Ultra-Uprate may be an attractive option for specific nuclear power plants where a large margin exists in the steam and power conversion system. Additional cost variances should be considered in a more detailed analysis, including: (1) a deductions for newly installed steam generators: (2- a expected shorter construction time for the uprate compared to licensing and construction a new plant; and, (3) the risk of a larger than expected final transition outage. Finally, the conclusions of the study suggest that development efforts on fuel technologies for current nuclear power plants should be oriented towards improving the fuel performance (fuel rods fretting-wear damage, assembly bow, pellet-cladding interaction, corrosion, uranium load, manufacturing, safety, back end costs, etc.) required to achieve higher burnup rather focusing on potential increases of the fuel thermal output.

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Appendix I: MathCad Files

I.1- RCS pumps are not replaced (M-File: "*RCS_no_pump-replacement*")

Determination of the RCS parameters: no pump replacement

References to external functions

Reference:D:\Rubiolo\APUU\NSSS model\Pump_characteristic_equation.mcd

Reference:D:\Rubiolo\APUU\NSSS model\Water_properties.mcd

Reference:D:\Rubiolo\APUU\NSSS model\Core_friction_coefficient.mcd

Input Parameters

Yellow boxes: entries for the optimization procedure
Blue boxes: outlet values

Core temperatures [fahrenheit]

Outlet: $Tout := 620.5$

Core bypass $bypassCO := 0.07$

Reference Power $PthRef := 3425 \cdot 10^{6} \cdot watt$

Uprate value $APUU := 0\%$

Friction coefficients

Steam Generators: $KSG := 0.939498 \frac{1}{m^{4}}$

Cold leg: $KCL := 0.330773 \frac{1}{m^{4}}$

Reactor vessel: $KRV := 0.548069 \frac{1}{m^{4}}$

Hot leg: $KHL := 0.059101 \frac{1}{m^{4}}$

Gravity constant

$g := 9.81 \frac{m}{sec^{2}}$

Primary Pumps

Reference pump power $WPUMPREF := 5329.534hp$

Main

$TRtoF(T) := \frac{(T - 459.67R)}{R}$ $TFtoR(T) := (T + 459.67)R$

$TCO\_OUT := TFtoR(Tout)$ conversion to [rankine]

$THOT(Tc) := [(1 - bypassCO) \cdot (TCO\_OUT - Tc) + Tc]$ Hot leg temp. is function of the bypass flow

$Pth := (1 + APUU) \cdot PthRef$ Core power after uprate

$massflow := 38952.3 \frac{lb}{s}$ guess value

$Tc := (551.5 + 459.67)R$ guess value

Solution

Given

$$Pth = massflow\cdot(1 - bypassCO)\cdot(H(TCO\_OUT) - H(Tc))$$

$$\frac{KCL}{\rho(Tc)} + \frac{2\cdot(KSG + KRV)}{(\rho(Tc) + \rho(THOT(Tc)))} + \frac{2\cdot\left[KCO\cdot(1 - bypassCO)^2\right]}{(\rho(Tc) + \rho(TCO\_OUT))} + \frac{KHL}{\rho(THOT(Tc))} = \frac{2\cdot\rho(Tc)\cdot g}{massflow^2}\cdot\Delta h\left(\frac{massflow}{4\cdot\rho(Tc)}\right)$$

Find the solution! $\begin{pmatrix} TCOLD \\ mRCS \end{pmatrix} := Find(Tc, massflow)$

$QRCS := \frac{mRCS}{\rho(TCOLD)}$ volumetric flow evaluate at the pump conditions

$TCO\_IN := TCOLD$

$mCO := (1 - bypassCO)\cdot mRCS$

$QCO := \frac{mCO}{\rho(TCO\_IN)}$ volumetric flow at the core inlet

Pressure drops

$\Delta PSG := \frac{1}{2}\cdot\frac{KSG}{\frac{(\rho(TCOLD)+\rho(THOT(TCOLD)))}{2}}\cdot mRCS^2$

$\Delta PRV := \frac{1}{2}\cdot\frac{KRV}{\frac{(\rho(TCOLD)+\rho(THOT(TCOLD)))}{2}}\cdot mRCS^2$

$\Delta PCL := \frac{1}{2}\cdot\frac{KCL}{\rho(TCOLD)}\cdot mRCS^2$

$\Delta PCO := \frac{1}{2}\cdot\frac{KCO}{\frac{(\rho(TCO\_IN)+\rho(TCO\_OUT))}{2}}\cdot mCO^2$

$\Delta PPU := g\cdot\rho(TCOLD)\cdot\Delta h\left(\frac{mRCS}{4\cdot\rho(TCOLD)}\right)$

$\Delta PHL := \frac{1}{2}\cdot\frac{KHL}{\rho(THOT(TCOLD))}\cdot mRCS^2$

$\Delta LOOP := \Delta PSG + \Delta PCL + \Delta PRV + \Delta PCO + \Delta PHL$ Total loop pressure drop

Pump parameters

$QPUMP := \frac{mRCS}{4\,\rho(TCOLD)}$ Pump volumetric flow rate per pump

$WPUMP := \frac{QPUMP\cdot\Delta LOOP}{WPUMPREF}$ Pump power normalized to a reference pump

Output

Reactor uprated power

$Pth = 3425\,10^6\,watt$

$APUU = 0\%$

RCS Flow rates and temperatures

In Fahrenheit degrees

$mRCS = 40625.58921\,\frac{lb}{sec}$

$TCOLD = 565.684K$

$TRtoF(THOT(Tc)) = 615.67$

$QRCS = 394395.24\,\frac{gal}{min}$

$THOT(Tc) = 597.411K$

$TRtoF(TCOLD) = 558.561$

Core flow rates and temperatures

$mCO = 37781.8\frac{lb}{sec}$

$TCO\_IN = 565.684K$

$TRtoF(TCO\_IN) = 558.561$

$QCO = 366787.6\frac{gal}{min}$

$TCO\_OUT = 600.094K$

$Tout = 620.5$

Component pressure drops

Steam Generators

$\Delta PSG = 32.898psi$

Cold leg

$\Delta PCL = 10.999psi$

Core

$\Delta PCO = 27.388psi$

Pumps

$\Delta PPU = 92.662psi$

Reactor vessel

$\Delta PRV = 19.192psi$

Hot leg

$\Delta PHL = 2.186psi$

Total loop

$\Delta LOOP = 92.662psi$

Primary pump normalized power

$WPUMP = 1$

I.2- RCS pumps are not replaced (M-File: “*RCS_Pump_replacement*”)

Determination of the RCS parameters: pumps are replaced

References to external functions

Reference:D:\Rubiolo\APUU\NSSS model\Pump_characteristic_equation.mcd

Reference:D:\Rubiolo\APUU\NSSS model\Water_properties.mcd

Reference:D:\Rubiolo\APUU\NSSS model\Core_friction_coefficient.mcd

Input Parameters

Yellow boxes: entries for the optimization procedure
Blue boxes: outlet values

Core temperatures [fahrenheit]

Inlet: $Tin := 558.561$

Outlet: $Tout := 620.5$

Core bypass $bypassCO := 0.07$

Reference Power $PthRef := 3425\,10^{6}\cdot watt$

Uprate value $APUU := 0\%$

Primary Pumps

Reference pump power $WPUMPREF := 5329.534\,hp$

Friction coefficients

Steam Generators: $KSG := 0.939498\dfrac{1}{m^4}$

Cold leg: $KCL := 0.330773\dfrac{1}{m^4}$

Vessel: $KRV := 0.548069\dfrac{1}{m^4}$

Hot leg: $KHL := 0.059101\dfrac{1}{m^4}$

Gravity constant

$g := 9.81\dfrac{m}{sec^2}$

Main

$TRtoF(T) := \dfrac{(T - 459.67R)}{R}$ $\qquad$ $TFtoR(T) := (T + 459.67)R$

Core parameters

$Pth := (1 + APUU)\cdot PthRef$ Core power after uprate

$TCO\_OUT := TFtoR(Tout)$ Conversion to [rankine]

$TCO\_IN := TFtoR(Tin)$

$mCO := \dfrac{Pth}{(H(TCO\_OUT) - H(TCO\_IN))}$ Core mass flow rate

$QCO := \dfrac{mCO}{\rho(TCO\_IN)}$ Volumetric flow at the core inlet

RCS Flow Rates and temperatures

$TCOLD := TCO\_IN$ Cold leg temperature

$THOT := (1 - bypassCO)\cdot(TCO\_OUT - TCO\_IN) + TCO\_IN$ Hot leg temperature

$mRCS := \dfrac{mCO}{(1 - bypassCO)}$

$$QRCS := \frac{mRCS}{\rho(TCOLD)}$$

volumetric flow evaluate at the pump conditions

Pressure drops

$$\Delta PSG := \frac{1}{2} \cdot \frac{KSG}{\frac{(\rho(TCOLD)+\rho(THOT))}{2}} \cdot mRCS^2$$

$$\Delta PRV := \frac{1}{2} \cdot \frac{KRV}{\frac{(\rho(TCOLD)+\rho(THOT))}{2}} \cdot mRCS^2$$

$$\Delta PCL := \frac{1}{2} \cdot \frac{KCL}{\rho(TCOLD)} \cdot mRCS^2$$

$$\Delta PCO := \frac{1}{2} \cdot \frac{KCO}{\frac{(\rho(TCO\_IN)+\rho(TCO\_OUT))}{2}} \cdot mCO^2$$

$$\Delta PPU := g \cdot \rho(TCOLD) \cdot \Delta h\left(\frac{mRCS}{4 \cdot \rho(TCOLD)}\right)$$

$$\Delta PHL := \frac{1}{2} \cdot \frac{KHL}{\rho(THOT)} \cdot mRCS^2$$

$$\Delta LOOP := \Delta PSG + \Delta PCL + \Delta PRV + \Delta PCO + \Delta PHL$$

Total loop pressure drop

Pump parameters

$$QPUMP := \frac{mRCS}{4\rho(TCOLD)}$$

Pump volumetric flow rate per pump

$$WPUMP := \frac{QPUMP \cdot \Delta LOOP}{WPUMPREF}$$

Pump power normalized to a reference pump

Output

Reactor uprated power

$Pth = 3425 10^6 watt$

$APUU = 0\%$

RCS Flow rates and temperatures

In Fahrenheit degrees

$mRCS = 40625.5798 \frac{lb}{sec}$

$TCOLD = 565.684K$

$TRtoF(THOT) = 616.164$

$QRCS = 394395.13 \frac{gal}{min}$

$THOT = 597.686K$

$TRtoF(TCOLD) = 558.561$

Core flow rates and temperatures

$mCO = 37781.8 \frac{lb}{sec}$

$TCO\_IN = 565.684K$

$TRtoF(TCO\_IN) = 558.561$

$QCO = 366787.5 \frac{gal}{min}$

$TCO\_OUT = 600.094K$

$Tout = 620.5$

Component pressure drops

Steam Generators

$\Delta PSG = 32.898psi$

Cold leg

$\Delta PCL = 10.999psi$

Core

$\Delta PCO = 27.388psi$

Pumps

$\Delta PPU = 92.662psi$

Reactor vessel

$\Delta PRV = 19.192psi$

Hot leg

$\Delta PHL = 2.186psi$

Total loop

$\Delta LOOP = 92.662psi$

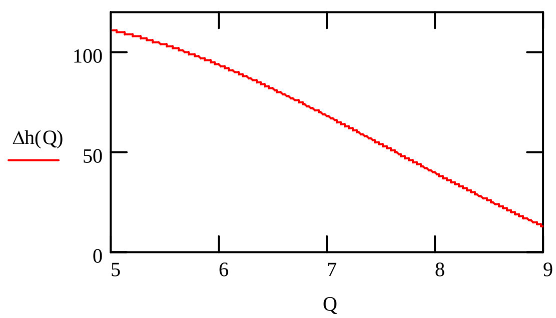
Primary pump normalized power

$WPUMP = 1$

I.3- Pump characteristic equation (M-File: "*Pump_characteristic_curve*"

Pump characteristic curve

$$\Delta h(Q) := \left[0.8174\left(\frac{Q}{\frac{m^3}{sec}}\right)^3 - 18.676\left(\frac{Q}{\frac{m^3}{sec}}\right)^2 + 113.46\frac{Q}{\frac{m^3}{s}} - 92.004\right]\cdot m$$



$$QMMF := 99600\frac{gal}{min}$$

$$\Delta PUMP\_MMF := 748.8\frac{kg}{m^3}\cdot 9.81\cdot\frac{m}{sec^2}\cdot\Delta h(QMMF)$$

$$\Delta PUMP\_MMF = 91.975psi$$

I.4- Core friction loss coefficient determination (M-File: "*Core_friction_coefficient*"

Determination of the Core Friction Coefficient

Reference:D:\Rubiolo\APUU\NSSS model\Water_properties.mcd

Core parameters

Inlet: $Tin := 551.5$ [fahrenheit]

Outlet: $Tout := 620.5$

Core mass rate $mcore := 35836.12\dfrac{lb}{sec}$

These values are only required one time to calculate the core friction losses

Core pres. drop (without support plates) $\Delta Pcore := 24.5psi$

Solution

$\rho in := \rho[(Tin + 459.67)R]$ conversion to [rankine]

$\rho out := \rho[(Tout + 459.67)R]$

$$KCO := \frac{\Delta Pcore\cdot(\rho in + \rho out)}{mcore^2}$$

$$KCO = 0.90024\frac{1}{m^4}$$

I.5- Water properties (M-File: “*RCS_no_pump-replacement*”)

Water Properties

Liquid water density (Pressure = 2250 psi)

$data :=$

T[K]	Density [kg/m^3]
500	842.8
510	829.8
520	816
530	801.5
540	786.1
550	769.7
560	752.1
570	732.9
580	711.9
590	688.3
600	661.2
610	628.3

$$F(x) := \begin{pmatrix} 1 \\ x \\ x^2 \end{pmatrix}$$

$n := rows(data)$ $\qquad$ $i := 0..\, n - 1$

$data := csort(data, 0)$

$X := data^{\langle 0 \rangle}$ $\qquad$ $Y := data^{\langle 1 \rangle}$ $\qquad$ $S := linfit(X, Y, F)$

Least-squares fitting function

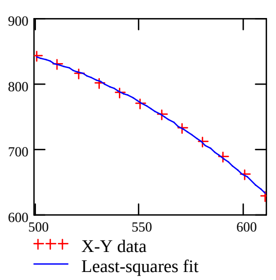
$fit(x) := F(x) \cdot S$

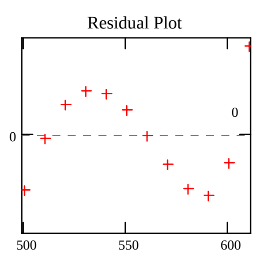
Sum of the squares of the residuals

$$\sum_i \left(fit(X_i) - Y_i\right)^2 = 56.802$$

$npoints := 50$ $\qquad$ $j := 0..\, npoints$

$$q_j := min(X) + j \cdot \frac{(max(X) - min(X))}{npoints} \qquad scale := max\left(\overrightarrow{\left|fit(X) - Y\right|}\right) \cdot 1.1$$





$$\rho(x) := fit\left(\frac{x}{K}\right) \cdot \frac{kg}{m^3}$$

Liquid water Enthalpy (Pressure = 2250 psi)

T[K]   Enthalpy [kJ/Kg]

data :=

500	978.7
510	1025
520	1071
530	1119
540	1167
550	1217
560	1268
570	1321
580	1376
590	1434
600	1496
610	1566

$F(x) := \begin{pmatrix} 1 \\ x \\ x^2 \end{pmatrix}$

$n := \text{rows}(\text{data})$ $i := 0..\, n - 1$

$\text{data} := \text{csort}(\text{data}, 0)$

$X := \text{data}^{\langle 0 \rangle}$ $Y := \text{data}^{\langle 1 \rangle}$ $S := \text{linfit}(X, Y, F)$

Least-squares fitting function

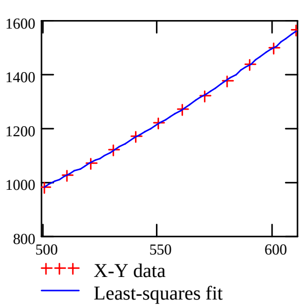
$\text{fit}(x) := F(x) \cdot S$

Sum of the squares of the residuals

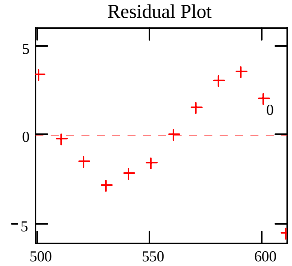
$\sum_i \left(\text{fit}(X_i) - Y_i \right)^2 = 88.325$

$\text{npoints} := 50$ $j := 0..\, \text{npoints}$

$q_j := \min(X) + j \cdot \frac{(\max(X) - \min(X))}{\text{npoints}}$ $\text{scale} := \max\left(\overrightarrow{\left|\text{fit}(X) - Y\right|}\right) \cdot 1.1$



Residual Plot



Water density: $H(x) := \text{fit}\left(\frac{x}{K}\right) \cdot \frac{10^3 J}{kg}$

$H(500K) = 982.097 10^3 \frac{J}{kg}$

Appendix II: EPRI BOP Assessment for the Power Ultra-Uprate

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Ultra Uprate Balance of Plant and Overview Issues

Product ID Number

January 2005

EPRI Project Manager

Gary Toman

Cosponsor:

Westinghouse Electric Co. LLC

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CITATIONS

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Al Cutter, Consultant

This document describes research sponsored by EPRI and Westinghouse Electric Co. LLC.

The publication is a corporate document that should be cited in the literature in the following manner:

Ultra Uprate Balance of Plant and Overview Issues, EPRI, Palo Alto, CA, Westinghouse Electric Co. LLC, Pittsburgh, PA and U.S. Department of Energy, Washington, DC: 2005 {Product ID Number}.

ABSTRACT

This report is part of an assessment of the practicality of a 150% uprate of a four loop pressurized water reactor and in general covers balance of plant issues. The uprate is based on modifying the internals of the reactor and changing the fuel design to allow 50% more power to be achieved. This report covers costs of converting the existing plant to a 50% uprated plant. It also considers the interactions of the plant with the transmission system with respect to stability and need for upgrade to accept the larger unit.

The modification of a plant to achieve 150% output is quite different from constructing a new plant having 150% capacity. Buildings and tanks near the unit must be moved, underground piping and cabling systems must be rerouted, and numerous major components in containment must be removed and replaced. Some of the work can be done during outages preceding the transition outage and much can be done in parallel with operations. However, conversion of the reactor and steam generation systems for the uprate must be done during a relatively long transition outage. The length of the outage and associated replacement energy cost is a significant factor in the economics of the uprate as are the cost of removal of major components that are radioactive. The report covers major issues to be resolved, identifies alternative approaches for implementing the uprate and provides an estimate of the cost of an ultra uprate.

CONTENTS

1 INTRODUCTION

This report is part of an assessment of the practicality of a 150% uprate of a four loop pressurized water reactor and in general covers balance of plant issues. However, many issues governing the overall project must be considered to assess issues and cost associated with the balance of plant. Accordingly, a number of issues related to the overall uprate are covered in part or in detail. The uprate is based on modifying the internals of the reactor and changing the fuel design to allow 50% more power to be achieved. The details of the modification of the nuclear systems and steam generation are being performed by Westinghouse Electric Company.

The modification of a plant to achieve 150% output is quite different from constructing a new plant having 150% capacity. While many components in an existing plant have additional margins allowing some increase in loading, those with the largest margins generally can accommodate no more than 20% uprates and many other components have much more limited margins. Often turbines are sized to assure that the original plant capacity is assured. Margin is contained in their capability such that they can have higher output if the system can supply more steam of adequate quality. In addition, portions of the turbines can be replaced to achieve substantial uprates. However, none of the plants under consideration can accommodate a 25 to 50% uprate using the existing turbine generator systems. Accordingly, three alternatives are considered here: A 25 % uprate; a 50% uprate implemented by adding a second smaller turbine generator system that increases the overall capacity; and a 50% uprate using a new 150% turbine generator system to entirely replace the original system.

With either alternative, a number of basic issues must be considered, which include:

- Performance of construction adjacent to and within an operating plant, and within and adjacent to its security zone
- Preventing trips of the operating plant from construction activity
- Performing major rework in radiologically contaminated and controlled areas of the containment and the auxiliary building
- Relocation of adjacent buildings, tanks, and other structures
- Relocation or working around existing underground pipes and cables including circulating water for the operating plant
- Upgrading plant circulating water capacity (capacity of heat sink (e.g., cooling tower, river or lake)) and environmental permitting
- Control of heavy loads near the operating plant and underground facilities critical to operation
- Control of construction in the vicinity of energized 345 or 500 kV lines and substation equipment
- Prevention of crane topple into the reactor and fuel buildings
- Restoration of rail facilities for transport of construction materials (including runaway train security issues)
- Tight control of transition outage lengths

- Assuring fuel pool capacity for a minimum of two full cores (1 old and 1 new)
- Actual capacity of equipment cooling and support systems as compared to original design levels
- Assessment of remaining lifetime of significant systems, structures or components which might restrict the useful life of the upgraded plant (e.g.; reactor vessel embrittlement)
- Cost of on site storage or transportation and disposal of a reactor head, core support structure components, steam generators, pressurizer, and reactor coolant pumps
- Cost of capital for efforts that must be performed well in advance of the availability of the output of the uprated plant.
- Development of a unified licensing basis for a plant with mixed old and new equipment (This may cause changes to original licensing basis and affect original systems and components that remain in service.)

In addition, some plant modifications or changes are desirable to allow the uprate. These include prior conversion to a digital control room, and licensing and construction of dry fuel storage. The transition to a digital control room in advance of the uprate will allow more rapid transfer to and integration of the new and uprated equipment. Transition to a digital control room at the time of uprate would greatly complicate the effort and likely increase the length of the main outage. The dry fuel storage facility (assuming Yucca Mountain is not available for receiving spent fuel) will be necessary to assure adequate space for off load of the entire old core and have adequate space for at least a full core off load of new fuel.

This report describes the issues and possible alternatives for balance of plant components and identifies potential costs of alternatives. The costs of importance are those that would occur that would be over and above those that would occur when constructing an alternate plant with the output equivalent to that of the uprate, whether it is nuclear or fossil fueled. This report assumes that as much of the existing equipment as is possible will be retained and does not include consideration of replacing or upgrading equipment for purposes other than the uprate.

Assumptions

This assessment is based on a few key assumptions that could have major affects on issues that must be considered and the expected cost of the uprate. These are:

1. The revised loss of coolant accident conditions (LOCA) will not cause an unacceptable increase in containment pressure. The pressure must not increase significantly and must remain inside the capability of the containment as it exists. An increase in pressure would require a reanalysis and possibly require modifications to the containment structure.
2. The revised mainsteam line break and LOCA conditions in containment will not cause a significant increase in peak temperature and pressure. A significant increase in MSLB or LOCA peak temperature and pressure could invalidate the environmental qualification of

all electrical penetrations, and safety-related cables, and electrical and I&C equipment in containment. If this occurred, re-qualification testing would be required for the equipment and replacement of some or all of the equipment might be necessary.

The changes to the plant are expected to remain within these assumptions. Per initial Westinghouse Electric Company assessments, the peak pressure and temperature conditions inside containment are not worse. However, the total thermal energy released during accidents will increase and removal the capability for removing the additional heat must be considered.

Plants under Consideration

The four loop Westinghouse plants listed in Table 1 are covered under this initial assessment. The age of these plants in 2014 is shown. 2014 is an estimate of the timing of the earliest deployment of an ultra uprate.

Plant	Capacity (MWe)	Initial Operations	Age in 2014 (years)
Callaway	1171	1984	30
Braidwood 1	1214	1989	25
Braidwood 2	1155	1989	25
Byron 1	1207	1985	29
Byron 2	1155	1987	27
Seabrook	1160	1990	24
Votgle 1	1215	1987	27
Votgle 2	1215	1989	25
Wolf Creek	1200	1985	29

Table 1. Westinghouse Four Loop Plants: Capacity and Date of Initial Operation

The capacities for these units range from 1155 to 1215 MWe resulting in 150% uprates from 1732 to 1822 MWe. For convenience, the nominal 50% uprate is referred to as 1800 MWe. A 25% uprate is referred to as 1500 MWe.

Uprating and Renewal

The ultra uprate can be viewed as uprating a plant to get a much large capacity, but really should be viewed as a chance for renewal and improvement of the plant. By the time the youngest of plants could be uprated, they will be at least 25 years old. If the concept is broadened to take in the entire population of PWRs, plants could be more than 40 years old. Accordingly, in addition to uprating by a large factor, an ultra uprate should include consideration of renewal of components and systems that have begun to age and as a chance to increase operating and safety margins where possible to lessen the stress on systems and components and thereby increase their longevity. However, given the plant specific nature of aging of structures, systems and components, this report covers only the items that must be replaced or modified to allow the uprate and does not consider the age of retained components. During the design of a specific uprate, known plant problems should be considered and resolved to get the greatest benefit from the upgrade.

The uprate of the plant will be difficult for the staff. Pressures will be high to return to service. Large temporary additions will be made to the staff to support the preparation for and implementation of the uprate. All efforts should be made to limit the stress to the permanent staff during the main outage and to encourage personnel to learn how the plant is being redesigned and reconstructed. This understanding will strengthen the staff and provide benefits in future years.

Uprate Levels and Considerations

Two levels of ultra uprate are considered here: 25% and 50%. At 25% and below, the existing reactor coolant pumps may be used. Above that point, new pumps must be installed. Accordingly, a 25% uprate is considered. The largest uprate based on the redesigned reactor core is 50%. The full 50% uprate is considered. The bulk of the assessment is based on a 50% uprate, because it is the bounding case. The alternatives that are considered for the 50% are replacement of the entire turbine/generator with an 1800 MWe system and addition of a 600 MWe turbine/generator in parallel with the existing 1200 MWe system. For the 25% uprate, upgrade of the current turbine/generator by 25% is considered as is placing a 300 MWe turbine generator in parallel with existing turbine generator.

As described later in this report, there is no significant advantage to implementing a 25% uprate. The installation of an 1800 MWe turbine/generator and abandonment of the existing system is neither cost effective nor practical with respect to transmission circuit breaker limitations. Accordingly, the bulk of this assessment is based on a 50% uprate using a 600 MWe turbine/generator in parallel with the existing 1200 MWe system.

2 TRANSMISSION ISSUES

The uprates being considered could result in units with capacities up to 1800 MWe. A unit of this size is considerably larger than the units in service today. Accordingly, the interactions of units this size with the transmission system must be considered carefully. Transmission system equipment rating limits and transmission system stability must be considered. The following subsections provide discussions of key uprated unit/transmission system considerations.

Substation Upgrades

If a 300 to 600 MWe turbine/generator is being added to each unit, the station bus will have to be extended and one or two breakers added. See Figure 1. Typically nuclear plants use a breaker and a half scheme where two components are connected via three circuit breakers between two main buses. With this scheme, one of the three breakers may be taken out of service for maintenance while the connected equipment remains in service. If a new 300 to 600 MWe generator is added, at least one new breaker will have to be installed. In Figure 1, a bay exists next to line 3 where the addition of one circuit breaker with disconnects would allow installation of a generator. If no such bay existed, then the buses would have to be extended and a minimum of two new circuit breakers would have to be added. Each breaker costs approximately $500,000 to $600,000. For most plants, additional transmission capacity will be necessary to assure capacity for full plant output especially in the event of the loss of one transmission feed. The addition of a transmission line is also likely to require the installation of one or more transmission circuit breakers.

If a totally new 1800 MWe generator is to be installed, much more significant substation costs will occur. At the time that nuclear plants were built, the normal current rating of 345 to 500 kV circuit breakers was 2000 amps. Assuming 500 kV is the transmission voltage, 2000 amps at 500 kV would allow 1732 MVA to flow. The system can operate between 475 to 525 kV. Given the 2000 amp breaker rating, 1,645 to 1,818 MVA could flow through a single circuit breaker if one of the breakers was out of service for maintenance, which would exceed the capability of a 2000 amp circuit breaker. 3000 amp breakers are now available and existing breakers can be upgraded. 2,468 to 2728 MVA would be able to flow through a 3000 amp breaker on a 500 kV system. Accordingly, the full power of the plant plus reactive load could flow through a 3000 amp breaker without output restrictions. However, more than the generating unit breakers would have to be replaced or upgraded, because substation configurations could exist where the plant output must flow through other substation breakers that are not in parallel with other paths. The changes would not be limited to circuit breakers. The ratings of disconnects, buses, wave traps, transmission lines would have to be considered. In addition, the rating of substations at the remote ends of the substation's lines would have to be considered and may have to be upgraded. Without the upgrading the substation ratings, full output from an 1800 MWe turbine generator will not be possible if the output had to flow through one circuit breaker, especially if transmission voltages were slightly low, which can occur at high load periods. For plants connected to 345 kV systems, the constraints are even greater. The full output of a single 1800 MWe turbine would exceed 3000 amp breaker ratings for nearly any possible transmission voltage. Accordingly, a single unit 1800 MWe generator would not be practical on a 345 kV transmission system.

If a 600 MWe turbine/generator were being added in parallel to the existing 1200 MWe system, the number of changes necessary to the surrounding transmission system would be more limited. The retiring of the original turbine/generator and replacement with an 1800 MWe unit will have rather large ripple effects and require not only additional transmission, but uprates of many components at the station and surrounding it to 3000 amp capability. However, the additional 600 MWe generator would have its own circuit breakers such that under a worst case situation 1200 MWe would flow through one circuit breaker and 600 MWe would flow through a separate breaker. The likelihood that many circuit breakers would have to be replaced or upgraded to 3000 amps would be reduced.

Two possible resolutions exist for an 1800 MWe unit that would limit the extent of changes and uprates required on the 500 kV or 345 kV transmission system. In the first, two 900 MWe generators would be placed in series on the turbine shaft such that half the output would come from each generator. The maximum power through each generator breaker would be limited to 900 MWe. The transmission substation would be configured such that the output from the two generators would be distributed more widely among the transmission grid and not tend to flow through one breaker or on one transmission line. The second possibility is similar but instead of two generators in series on the shaft, the high and low pressure turbines would be separated from one another and each would supply an individual generator. The result would be similar with respect to the transmission system but the sizes of the generators would be unequal.

No matter whether a 600 MWe or an 1800 MWe balance of plant are added, a new output transformer and will be necessary along with the transmission components that link it the substation. Splitting the 1800 MWe between two smaller generators will require two main transformers, associated breakers and buses. However, by doing so, use of more commonly available technology and smaller components to transport occurs.

Increased power requirements for the proposed new reactor coolant pumps will probably require replacement of the startup and station auxiliary transformers as well.

Substation Costs	**1800 MWe**	**(2) 900 MWe**	**600 MWe**
New Main transformer	1	2	1
Startup Transformer	1	1	1
New Circuit Breaker	1 or 2	1 or 2	1 or 2
Uprate All Circuit Breakers	Likely	Unlikely	Unlikely
Ground Mat Uprate	Likely	Unlikely	Unlikely
Bus Uprate	Likely	Unlikely	Unlikely
Transmission Line - New	Likely	Likely	Likely
Uprate Surrounding Substations	Likely	Unlikely	Unlikely

Table 2. Substation Cost Items

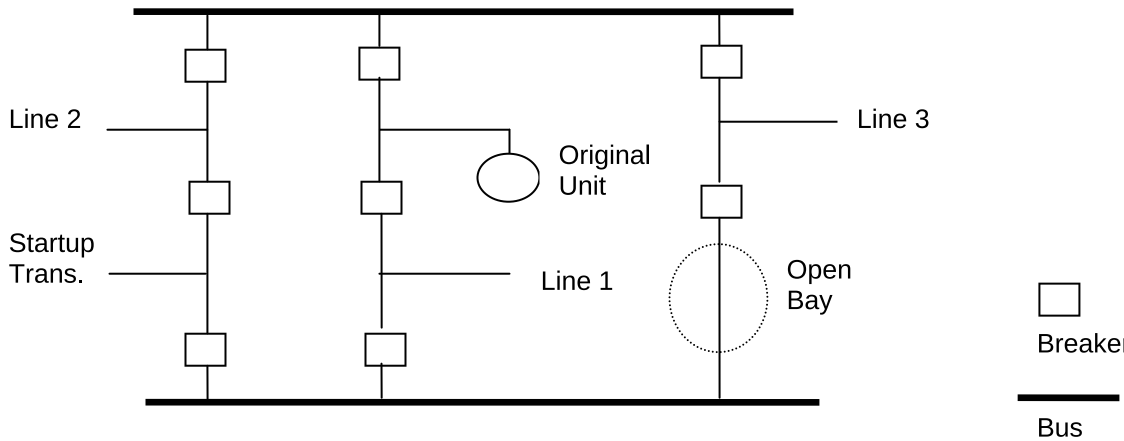

Figure 1. Typical Breaker and a Half Scheme

Note: An additional 600 MWe generator could be connected to the open bay by adding one more circuit breaker and sets of disconnect switches. Additional auxiliary power is likely to be needed. Accordingly, either the startup transformer will have to be replaced with one of additional capacity or another string of circuit breakers will have to be installed. Most plants will need at least one more transmission line installed to prevent outages of a transmission line from requiring reduction in plant output.

Transmission Interactions

Appendix A contains the full transmission interaction report. The following summarizes the results of that study. This study evaluated the full 50% uprate, which envelopes a 25% uprate.

- The existing transmission capacities at the generation stations for most of the selected nuclear power plants (except for Byron nuclear power plant) may be sufficient for supporting the 50 % uprating according to the data available for this study if all of the transformers/lines are in service.
- For the Byron nuclear power plant, it is necessary to upgrade the transformers and transmission lines because the N-1[1] operating requirements are not met even if all of the related transformers / lines are in service after the 50 % uprating of the power plant. The transmission enhancements should meet the NERC operating standards, while allowing maintenance of the transformers and transmission lines directly connected to the uprated plant.

[1] In a contingency analysis, engineers present a model of the electrical system with hypothetical demand conditions and a base case of operating generators and lines. Large generators and major lines are then taken off line one at a time to mimic unplanned outages. This is called an N-1 contingency analysis: all but 1 of the n pieces of major equipment in the electrical system is assumed to operate normally.

- For Byron (1&2), Wolf Creek, and Comanche Peak (1&2), with 50% uprates, and with one line out of service from the corresponding plant, the adjacent lines would be loaded to levels to above 85% of the static ratings. Given the approximate nature of this study, any loading above 85% warrants further study. Note: Full output would be possible if the uprate is limited to 25%.
- A potential reactive power supply and voltage regulation problem has been identified at the Callaway plant when the nuclear generator is not in operation. The study did not identify other voltage control issues with the selected plants. Uprating the plants will actually help to negate voltage collapse problems in their immediate areas provided that the uprating includes addition of a second turbine generator or a generator of large MW and MVAR capability.
- In a deregulated environment, transmission networks have loading patterns much different than they were designed to accommodate. This is particularly true of networks in the vicinity of nuclear plants. When the plants are not in operation, the transmission lines may be highly loaded transporting power from other sources. Providing reactive power supply and voltage regulation during these times may become necessary to maintain acceptable system voltage to operate the plant auxiliary equipment. This concern is most applicable to the Callaway, Wolf Creek, and Seabrook stations since they are single unit plants. If these plants are selected for uprating, a careful study should be made to quantify the need for reactive power for operating the transmission network when the reactor is not operating.
- The percentage of time the transmission network can reliably accept full power from the plant is a key consideration in deciding to uprate. If an uprated plant would be large in comparison to other plants, it is likely that its output will have to be reduced under light load conditions to have sufficient spinning reserve to protect from the loss of the uprated plant. It is more difficult to operate a large nuclear plant in a load following mode than other types of plants. This issue seems to be of more concern if the Wolf Creek, Callaway or Vogtle plants are considered for uprating.

To a lesser extent, the transmission effects study looked at the economic merits of uprating these plants based on prevailing power production costs in the areas which the plants reside (see Section 6 of Appendix A). The study also raised the issue that providing network security may require operating plants at some of the locations at lower power levels during times when system load is low.

The study indicates that tripping of an 1800 MWe unit from full load will not cause the transmission system to go unstable. However, some of the plants may have to operate at less than full load at light grid load periods that are likely to occur in Spring and Fall. Grid loads are much lower at night and on weekends in Spring and Fall. Given that U.S. nuclear plants do not follow load, uprated units might have to sit for long periods of time at lower than full load. There would be a loss of revenue that would be much less than the losses associated with replacement costs during peak conditions, but nonetheless significant. While it was beyond the scope of this study to calculate that loss of revenue, low revenue during low load periods must be considered when calculating the value of proceeding with an uprate.

The study indicates that some transmission upgrade is likely to be needed for all plants and that more significant transmission upgrades would be needed for Byron, Wolf Creek and Comanche Peak.

3 CYCLE LENGTH EFFECTS

The fuel cycle length for the annular flow fuel used in the uprate is likely to be 12 months. The units under consideration currently have 18 month refuel cycles. Assuming a 30 day refuel outage, the maximum capacity factor for an 18 month cycle is 94.7%. The maximum capacity factor for a 12 month cycle is 92.3%. In comparison to nuclear power generated with an 18 month refuel cycle, as would be the case of keeping the original refuel cycle and building a new 18 month cycle unit, 2.4 % of possible output would be lost each year after the uprate. For a 50% uprate, 43.2 MW years/year would be lost. Table 3 provides the cost of the expected yearly loss at various replacement costs for an 1800 MWe Unit. Table 4 provides the costs for a 1500 MWe (25% uprate) unit.

Outage Length (days)	Replacement Cost ($/MWH)	% Reduction in Output	Lost MWe Years/Year	Yearly Cost (Million)
30	$25	2.4	43.2	$9.5
30	$40	2.4	43.2	$15
18	$25	1.58	28	$6
18	$40	1.58	28	$9.7

Table 3. Lost Revenue from a 12 Month versus 18 Month Refuel Cycle (1800 MWe Unit)

Outage Length (days)	Replacement Cost ($/MWH)	% Reduction in Output	Lost MWe Years/Year	Yearly Cost (Million)
30	$25	2.4	37.5	$8
30	$40	2.4	37.5	$12.7
18	$25	1.58	23.7	$5
18	$40	1.58	23.7	$8

Table 4. Lost Revenue from a 12 Month versus 18 Month Refuel Cycle (1500 MWe Unit)

These post-uprate losses due to cycle length are appreciable. Table 5 summarizes the present value cost for shorter refuel cycles for 20 year periods with typical inflation and cost of money rates. Depending on the uprate size, cost of replacement power, inflation rate and cost of money, the present value costs range from $63 to $239 million.

In addition to lost capacity factor, there are some other lifetime cost factors associated with more frequent refueling that may be non-trivial. The fuel cycle cost will be higher for the same net uranium consumption due to fuel fabrication and handling costs associated with the increased number of fuel assemblies that need to be purchased over remaining lifetime. There may also need to be some staff increase to handle and inspect new fuel and transfer old fuel to dry storage. There will also be an impact on how fast fuel will need to be moved through the pool (with a fixed number of storage locations) to dry storage, and an increase in dry storage space required. The need for additional fuel storage space will need to be considered. If Yucca Mountain opens and allows disposal, there will be higher disposal and transportation costs as well.

Uprate Size	Yearly Lost Revenue (Millions)	20 Year Present Value with 2% Inflation Rate and 5% Cost of Money (Millions)	20 Year Present Value with 3% Inflation Rate and 9% Cost of Money (Millions)
50%	$6	$96	$75
50%	$9.5	$152	$120
50%	$15	$239	$190
25%	$5	$79	$63
25%	$8	$127	$101
25%	$12.7	$202	$160

Table 5. Present Value of 20 Year 12 Month Cycle

For the 25% power uprate, intermediate length fuel cycles may be possible. Assuming a 15 month refueling cycle, the following estimated yearly cost increase for 30 day out would range from $3.2 to 5.2 million/year. The present value of these costs ranges from $49 to $80 million for 2% inflation and 5% cost of money to $39 to $64 million for 3% inflation and 9% cost of money.

4 DISCUSSION OF PRACTICALITY OF 25% UPRATE

To achieve uprates above 25%, the reactor coolant pumps must be replaced with higher capacity units. The pumps are a significant expense and will require the associated electrical penetrations and cables to be placed and are likely to require switchgear upgrades. Accordingly, a 25% uprate is appropriate to assess.

Flow assisted corrosion is not expected to be a significant problem for the existing steam lines through a 50% uprate.[2] However, the pressure drop between the steam generator and the turbine inlet is expected to increase by 65% (approximately 30 psi). Such an increase could impact the on the existing moisture separator between the high and low pressure turbines. Accordingly, some or all of the steam lines may have to be replaced. Two options exist for the uprate: Replace component in the existing turbine/generator to attain the full 125% output, or add a new 25% turbine in parallel.

Uprate of Existing Turbine Generator

The upgrade the entire original turbine generator has both advantages and disadvantages. Most of this work would have to be done during the upgrade outage with the possibility that the work could become critical path.

Outside containment steam and feedwater line replacement may be necessary to reduce pressure drop. The MSIVs, turbine stop and control valves will have to be replaced. The bottom outer shells of the turbine will be retained, but the inner shells, turbines and upper outer shells will be replaced to achieve the desired power. The generator would have to be replaced and the condenser would have to be rebuilt to achieve the desired heat transfer. The circulating water system pumps will have to be replaced to achieve greater pressure and flow. For river/lake cooled plants the intake structure will have to be upgraded to allow a greater cooling flow. For closed loop cooling tower plants, 25% more make up water will be necessary. The main transformer will need to be replaced.

The uprate of the generator is a large uncertainty. A 1500 MWe generator that fits within the envelope of the current generator will be a difficult, if not impossible, engineering problem. The generator diameter is essentially limited by the size of the railroad rights of way. The diameter cannot exceed the railroad right of way width and height. For a new plant, the length of the machine could be increased to allow more power output. For an existing plant with length and pedestal constraints, increasing length would not be practical. Rotor cooling will probably be the limitation and will require a water cooled rotor. Water cooled rotors are rare (only 4 in use in US reactors (Comanche Peak and Grand Gulf). Achieving 1500 MWe reliably in the same foot print as the current generators will be difficult.

Large sections of the turbine generator system and the associated auxiliary equipment will have to be replaced or upgraded. The cost of the effort could approach the cost of building a new 25% turbine generator.

[2] Per discussions with Doug Munson, EPRI Project Manager for flow assisted corrosion issues.

The advantages of uprate of the existing turbine generator in comparison to installation of a new turbine generator are:

- Little change to transmission switchyard beyond transformer replacement
- Less disturbance to overall site
- Lower likelihood of need for long outages prior to transition outage
- No control problem as would occur with paralleled units of significantly different capacity.

The disadvantages are:

- Achieving 1500 MWe in the foot print of the current 1200 MWe generator may not be possible
- Turbine/generator change out activities could become critical path
- Much larger set of activities during transfer outage
- Likelihood of "missed" item in upgrade that could cause problems during subsequent operation (e.g., support component that was not upgraded)

Table 6 provides an estimated cost for upgrading the existing turbine/generator system.

Task	**Cost**
Turbine Upgrade	$100,000,000
MSIVs (total for 4)	$2,400,000
Steam lines	$8,000,000
Moisture Separators	$15,000,000
Condenser Upgrade	$10,000,000
Circulating Water Upgrade and Pump Upgrade	$20,000,000
Intake structure upgrade	$10,000,000
Generator and Exciter Replacement	$20,000,000
Iso-phase Bus Replacement	$5,000,000
Main Transformer	$6,000,000
Water Treatment upgrade	$500,000
Condensate and Feedwater Pump upgrade	$5,000,000
Electrical System Upgrades	$10,000,000
HVAC Upgrades	$2,000,000
Service Water Upgrades	$8,000,000
Total	$221,900,000

Table 6. Estimated Cost of Upgrading Existing Turbine/Generator System by 25%

Addition of a 25% Turbine/Generator

Building a new 25% capacity (300 MWe) turbine generator will cost between $200 and $440 million.[3] There will be a difficult control problem paralleling a 1200 MWe machine with a 300 MWe turbine/generator, especially with respect to feedwater. For a small additional cost, the new turbine could be slightly oversized to allow operation margins to exist on the original turbine generator, which should increase its longevity. With construction of a new turbine generator, most of the work could be done while the original unit is operating. However, the existing circulating water lines are likely to have to be relocated to allow construction of the 25% unit. Given that the turbine generator can essentially be completed before the transition outage, the work except for final connection and testing would not be critical path. The building of a new separate 25% unit will require additional high voltage substation breakers to be installed

Advantages of a new turbine generator versus uprate of the existing system are:

- System can be constructed in parallel with operation
- New electrical system can be built without having to disrupt the existing electrical system
- The system and its auxiliaries are designed and built as a unit. There is less likelihood of missing a needed component as could occur in uprate of the existing unit
- Little likelihood of being critical path during transfer outage except for final connection and testing

Disadvantages:

- Circulating water lines from existing unit likely to have to be relocated during outage to allow construction
- More transmission substation equipment needed
- Control of significantly differently sized units may be problematic

25% Uprate Conclusion

A 25% uprate reduces the inside containment work in that the reactor coolant pumps do not have to be replaced. However, the head, core and support structure and pressurizer still have to be replaced and will still control critical path. It is unlikely that the outage length will be significantly shorter.

The uprate of the existing turbine/generator is likely not to be possible because development of a generator that will fit within the length constraints of the existing generator that is still transportable is unlikely. If it is possible, the generator is likely to be exotic, which may lead to unforeseen operating problems or failure mechanisms. The cost of uprating the existing turbine/generator approaches the low end cost for installation of a new 25% turbine/generator.

The costs related to outage duration will not be significantly different for a 25% uprate from that for a 50% uprate. The length of the outage may be a few weeks less but this is well within the uncertainty of the outage length.

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[3] Based on scaled cost for construction of a new unit (New Finnish unit and AP-1000 per www.world-nuclear.org)

Essentially, the difference in cost between the 50% and 25% uprates will be the costs of the replacement reactor coolant pumps, cable and penetrations and the difference in the cost of the turbine/generator system. If a 25% uprate is considered, the likely route would be the addition of a 25% turbine/generator rather than the uprate of the existing system.

5 NORMAL ELECTRICAL POWER ISSUES

A new electrical system to support non-safety BOP loads is expected to be installed for the new turbine/generator, no matter which size turbine or style of generator. For the residual plant that is not being replaced, power loads will increase for a number of components. A number of pump loads are increasing, a few new pumps are being added and containment cooling fans loads are increasing. In addition to requiring transformers and switchgear with sufficient capability, power cables will need to be replaced and for in-containment applications electrical penetrations will need to be replaced. Table 7 provides a list of significant pumps, fans and heater requirements.

Pump, Fan or Heater	Comment
Circulating Water Pumps	Uprate or add new pump (New trash racks likely for open loop systems)
Cooling Tower Booster Pump	For plants currently without Tower
Closed Cooling Water	Uprate
Reactor Coolant Pumps	Replace with higher capacity (replace penetration and cable) (18 MWe additional load for 4 pumps)
Containment Cooling Fan	Replacement not needed
Pressurizer Heaters	Larger heaters (replace electrical penetration and cable)
Auxiliary Feedwater	Replace pumps and motors with larger capacity units
Residual Heat Removal	Adequately sized. Replacement not needed
Intermediate Pressure Heat Removal	Replace pumps with motors with larger capacity units (replace cables)

Table 7. Pumps, Fans, and Heaters Being Uprated or Installed

The electrical power penetrations are generally modular in the vintage of plants under consideration and modules can be replaced without requiring structural changes to the penetration openings. The penetrations have to be replaced due to the significant increase in normal current and change in potential fault current. Additional penetrations may be have to be installed in spare openings to accommodate the significantly larger cables for the reactor coolant pumps. Both 480 V and 13 kV power penetrations will be affected. For the reactor coolant pumps, size of the 13 kV cables and penetrations will have to increase to handle the additional current. Power cables will have to be replaced for pressurizer heaters and containment cooling fans. Tray loadings will have to be carefully considered. Cabling that is contained in conduits could be a problem if the conduits size is small with respect to the size of the replacement cable. In such cases, the conduits may have to be replaced or an alternate path for the cable developed.

Normal power supply bus loadings will increase. The significant change in pump load will likely require some circuit breakers to be changed to higher ratings and auxiliary and startup transformers are likely to have to be replaced with transformers with higher ratings along with the transformer to bus cables. For example, for a 50% uprate, the reactor coolant pump motor will increase from 8000 hp to 14,000 hp, a 75% increase. A number of large pumps and motors will run slightly more than 50% greater power to be able to attain flows with existing systems. Accordingly, auxiliary loads will be somewhat higher than 50% greater than pre-uprate loads.

6 SAFETY ELECTRICAL POWER

Additional pumping capability will be needed for auxiliary feedwater and intermediate pressure safety injection. The units being evaluated are all post-TMI unit, which tend to have two large diesel generators of approximately 8 to 9 MWe capacity. The diesel generators have excess capacity for continuous emergency operation and have been sized to start large motors. A plant specific analysis will be required once the new emergency loads are known to determine if the diesel generators have sufficient capacity and startup capability for the new loads. The likelihood exists that an additional diesel will be needed to meet station blackout requirements. If a new diesel is needed, increased diesel fuel storage capacity will also be needed.

Additional decay heat from the new core could result in substantial reduction in the plant capability to meet station blackout considerations. A new coping analysis will be required, which will result in changes to the plant, or in the need for installation of an alternate AC power source.

For plants implementing an uprate, modernization of the electrical switchgear system (5 to 15 kV systems) is highly recommended if it has not already been performed. New, much larger power cables will be needed for intermediate pressure safety pumps.

7 STEAM AND FEEDWATER PIPING AND PENETRATIONS

The steam lines will have to be increased in diameter. While the flow is increasing by 50%, the affects of flow induced corrosion is not expected to be a significant problem. However, pressure drop between the steam generator and turbine inlet is will increase.

$$\Delta P = \frac{3.36E-6 * f * L * W^{2*}\overline{V}}{d^5} \quad \text{Reference [3]}$$

where:

ΔP = pressure drop, psig
f = friction factor
L = length of pipe in feet
W = flow, lbs/hour
$\overline{V}$ = Specific Volume, cubic feet/lb
d = diameter of the pipe in inches.

For a specific system with a known flow and pressure drop, $f*L*\overline{V}$ can be calculated for a given pipe diameter. One of the PWRs has a 42 psi drop between the steam generator and turbine at nominal flow. At 1.5 times the flow and the same line size, the pressure drop increases to 98.6 psig. To maintain the original pressure drop, the steam line has to be increased from 32 inches to 38 inches. A 36 inch diameter pipe will result in a 55 psi pressure drop. A 98.6 psi drop will cause pressures between 690 to 730 psia at the turbine inlet, which is significantly below the current inlet pressures. In this range, it is likely that the throttle valves would be wide open and chocked flow would occur at the first stage blades of the high pressure turbine. The exhaust of the HP turbine would likely be wet and exhaust bowl erosion would be likely. Erosion of the HP turbine exhaust line and all of the components up to and including the moisture removal vanes of the moisture separator would also be likely. Moisture levels in the low pressure turbines would increase the degradation rate of the blades that hard faced. Accordingly, replacement of the steam lines with larger diameter piping is desirable to reduce the pressure drop at the turbine inlet. An alternate would be to modify the high pressure turbine and replace the moisture separators to reduce the effects of lower pressure. With respect to the steam line penetrations, two possibilities exist: Replace the penetration or retain the penetration and add concrete coolers. The first could impact schedule and the second will leave a permanent steam line resistance and require a new system to maintain cooling. The cost of modifying penetrations has been assumed.

8 PREPARATION AND TRANSITION OUTAGE LENGTHS

The uprate will be performed on an existing operating plant. Accordingly, the output from the plant will be lost for the period of the transition. Controlling the length is critical to assuring the economic viability of the ultra uprate. The initial concept is to perform as much construction and startup testing as possible prior to the main transition outage to assure that the transition outage is as short as possible. An optimistic transition outage length is in the vicinity of 12 months for the 50% uprate. It might be possible to complete a 25% uprate in as little as 9 months due to a somewhat shorter testing and startup program.

Even with a 9 month outage, the cost of replacement power is significant. Assuming that the outage is taken from the beginning of the fall through the end of the following spring and that contracts are in place for the replacement power, replacement costs will still be high. The range may be from $500,000 to $1,000,000 per day, which equates to $137 to $273 million for a nine month outage and $183 to $364 million for the 12 month outage.

Performing the transition outage in less than 9 months will be difficult. The core structure, core, reactor head, reactor circulation pumps, pressurizer and steam generators must be replaced and the mainsteam lines and new mainsteam isolation valves must be connected before startup testing of the new turbine is possible. All control room modifications must be completed as well. Experience with steam generator replacement on four loop PWRs in 1988 and 1989 indicate an outage length of five to six months is required for a much less complex evolution.

Performance of some of the work will be necessary during outages that precede the transition outage. Some work will be dictated by conflicts between the location of the new turbine and existing structures and underground components necessary for operation of the original reactor. This could include circulating water pipe, startup transformer power and control cables, fire piping, and various safety related and operationally important water tanks. During a number of outages before the final transition outage, relocation of components and structures affecting safety and operations will have to occur. The uprate efforts during these outages will have to be choreographed to not significantly impact outage length or that the increased outage length is within the overall targeted outage costs. In addition to the pre-transition outage efforts, savings may occur from moving activities from the final transition outage to earlier outages. However, the size and timing of pre-transition outage costs must be considered in that no payback on these expenditures would occur for four or more years.

The length of the transition outage may be approached by considering the types of critical path activities.

Basic assumptions concerning the transition outage are:

- Turbine plant work has progressed to the point of all equipment essentially being available and start-up tested to the point where live steam must be available to test further. All line flushing and tests not requiring steam will have been performed.

- The control system has essentially been linked to a mockup of the control room and verified as being operable to the extent possible. The testing of the controls would be nearly complete; transition to the actual control room would be the next step. After the uprate, the "mock up" control room could be used as a backup control room or be used as an emergency support center.
- All necessary measurements have been made in previous outages for reactor internals fit ups, reactor head, pumps, steam generators, piping and pressurizer and any necessary changes in supports and restraints. The logistics and order of work and alternate paths should problems occur have been developed.
- The simulator has been prepared and operators have been trained on the new system and any interim state procedures that are necessary.

Essentially, all possible preparation work and startup testing have been completed that can be done. The major activities once the shutdown begins are:

Turbine Area

- Connect circulating water lines to the new condenser
- Disconnect old feedwater system and connect new turbines feedwater system
- Disconnect old steam lines, connect new MSIV, new steam lines, rework safety relief valves

Auxiliary Building

- Uprates to long-term emergency cooling
- MSIV removal and replacement
- Disconnect safety relief valves, change orifices, reset, test, reinstall, reconnect to new steam lines
- Feedwater and steam line segment upgrade

Containment

- Head removal (move out of building as soon as possible)
- Fuel Off-load
- For plants not having an equipment hatch, cut an opening in the containment wall
- System flush and system decontamination
- Core barrel and support structure removal
- Core barrel and support structure removal from building (interrupts all containment work due to dose)
- Installation of staging and temporary shielding
- Remove steam generators
- Remove primary piping
- Remove reactor coolant pumps

- Remove pressurizer relief valves (ship off site for resetting)
- Remove pressurizer
- Replace pressurizer
- Replace pressurizer heater cable and penetration
- Reinstall pressurizer relief valves
- Replace reactor pumps
- Reactor Pump 5 kV cable and power penetration replacement
- Upgrade containment coolers and cooling fans
- Containment fan cable penetration replacement
- Install higher capability primary piping supports and modify steam generator and RCP supports
- Install new primary piping
- Install new RCP, including new cables and electrical penetration modules
- Install new steam generators
- Install new core barrel and support structure
- Restore containment and system integrity (See Section 10).

The list of major work items is extensive and many activities will have to be completed under the constraints of radiological controls. Once all of the equipment is installed and system integrity has been demonstrated, startup testing and low power testing must occur.

9 OPERATING SITE SECURITY AND MODIFICATION ISSUES

During the period preceding the main uprate outage, the work will be within and around an operating plant. Plant security must be maintained. Heavy loads must not be dropped near or against the operating plant's buildings. Modification activities that could affect the operating reactor would be under tight control with 10CFR50.59 and plant review board controls are likely to be in effect for any activity close to or connecting with operating equipment and safety systems.

Special security procedures will have to be implemented to allow construction activities to take place near and against the operating plant. The design of these procedures to allow more flexibility for the construction area, while maintaining adequate security for the operating unit will be crucial. All uprate activities within the operating plant will have to be within the normal constraints of plant security, which will require additional time and staff for completion of activities.

Control of heavy loads near the reactor and fuel buildings to prevent damage will be critical and will cause additional expense to preclude crane topple. This concern will continue for the fuel building for the entire period because it will contain used fuel throughout the uprate process. The protection of the reactor building will remain important the outage period because of economic reasons. Damage to the containment during the uprate outage will likely cause severe concern and extension of the outage period.

Once the fuel is offloaded to the fuel pool during the transition outage, it will be desirable to essentially decommission the reactor and auxiliary building and turn them into essentially normal construction sites. At that point, the modification controls for an operating plant would cease and more normal construction practices would begin. Unfortunately, much of the reactor building will remain radioactive. At best, if radioactive contamination remains, the construction activities are likely to proceed at half pace or less due to the radiation work permit process and contamination processes. Control of airborne contamination from the large amount of cutting of radioactive metals will be necessary. Decontamination of the bulk of the reactor and auxiliary buildings will be desirable thereafter. While such activities may take days to complete, the gain in productivity is likely to be high, especially if loose contamination can be limited to small portions of containment and auxiliary buildings.

10 CONTAINMENT ACTIVITIES

The implementation of the uprate causes the magnitude of the in-containment activities to exceed any efforts since the time of construction. In addition, much of the initial work will entail cutting and removing radioactive components. Reactor head, core barrel and support structure, steam generator, pressurizer, reactor pump, and primary steam and feedwater line replacement will each have been performed somewhere in the world prior to the transition outage. However, such efforts will not have all been done during the same outage. Logistics will be critical with many activities demanding the use of the polar crane and access to the equipment hatch or opening. The core barrel and support structures are highly radioactive and cannot be moved to the fuel pool. It is likely that all activities in containment will have to cease while these components are being removed from the building and fitted into shielded cases for removal from site. While steam generators can be replaced in as little as 30 days, it is doubtful that all of these replacements can be crammed into a short period. The operating and outage control staff will be operating in a high level of overload if too short of a period is attempted.

It will probably be necessary to establish the containment as a construction zone, suspending the normal plant procedures for modification to an operating plant. Imposing the rigorous design change control and verification processes normally used to control nuclear grade integrity would result in significant extension of the outage. Accordingly, a post installation walkdown, verification of construction integrity, and verification of no disruption to systems, structures or components that were not part of the modification process will be required. This will need to be a part of the preparation of the containment for fuel load.

Should modifications be required in the containment itself, such as increasing steam line penetration diameter or cutting an access hatch, a containment over pressure test would most likely be required, as well as an integrated leak rate test.

11 SITE SPECIFIC CONSIDERATIONS

Cooling Source

A key concern for all plants with the possible exception of Seabrook will be availability of cooling water from the associated lake or river. Byron, Calloway, and Vogtle have cooling towers, which do not have an additional 50% thermal capability. New licenses for waste heat will be required of the EPA and state authorities if the sink is a river or lake. The plants with cooling towers will have to build additional towers. The plants without cooling towers are likely to have to build cooling towers if the associated estuary has reached it heat carrying limit. Seabrook is the only plant having no significant problem with additional cooling water. The cooling path for a second unit is available even though construction on that unit was not completed.

Calloway is 5 miles from its cooling source. Currently, Calloway uses 20,000 gpm for cooling with 5,000 gpm returned to river 15,000 gpm lost by evaporation. If an additional 10,000 gpm is necessary, increased pumping and new lines are likely.

Wolf Creek is likely to need cooling towers in the summer because under adverse wind and humidity conditions, the man-made lake is unable to provide adequate cooling for the plant. Increasing the plant size by 50% is likely to exacerbate these events or exceed the capacity of the lake on a continuous basis.

Comanche Peak is cooled by a manmade lake, which does not have enough cooling capacity in peak summer temperature conditions to allow full plant output. Accordingly, a cooling tower will be needed. Additional water may have to be pumped to the site to support makeup for the cooling tower(s).

Containment Types and Equipment Hatches

Braidwood 1 & 2, Byron 1 & 2, Callaway, Vogtle 1 & 2 and Wolf Creek have 3-D post-tensioned concrete cylinder containments. Comanche Peak 1 & 2 have reinforced concrete cylinder with steal liner containments. Seabrook 1 has a reinforced concrete cylinder with steel liner containment and a second steel containment. [1]

Not all plants have equipment hatches large enough to allow removal of the steam generators and reactor head. Wolf Creek and Callaway have 20 foot hatches that are large enough. Comanche Peak has no hatch and will require a hole to be cut in containment. Comanche Peak is replacing steam generators prior to 2008. Plants that have replaced steam generators early, like Comanche Peak, will have to consider writing off the remaining value of the existing steam generators if they are going for ultra uprate.

In addition to the size of the equipment hatch, an adequate area around the circumference of the containment must be clear at ground level to allow staging of equipment and cranes. No new plant equipment may be located in that zone. Accordingly, for plants with access hatches, the selection of the location for the new turbine building must consider equipment hatch location.

Plant Layout

While the plants under study are all four loop designs, there are many variations. Figures 2 through 5 give the basic plant layouts for the auxiliary, reactor, fuel, and turbine buildings. The layouts are a mix of older designs started before turbine blade projectile concerns arose and newer designs with the turbine axis in line with the center of the reactor building. While there appears to be four basic layouts, there are considerable differences between even the "like" sites. These include placement of circulating water piping, the use of cooling towers or direct lake, river or sea cooling, the placement of important tanks, the proximity of buildings around the site and the availability of land around the building. No site has a clear space adjacent to the mainsteam leads of the existing plant that is clear of above ground and below ground obstacles.

All plants will have conflicts related to circulating cooling water piping. Figure 6 shows the conflict for Callaway. The location of the circulating water lines is appropriate for the installation of the new turbine. Additional lines can be added to complete the cooling required for the new unit. However, before the new unit can be constructed, the existing lines for the operating unit need to be rearranged to allow construction of the base mat for the new turbine hall. Limited excavation may be possible around the circulating water lines during operation. However, they are critical to operation and a break would be unacceptable and require shutdown and a significant period to repair. Assuming that adequate cooling can be established using the same lines (e.g., increase flow), the new turbine/generator plant must either be built over the existing lines or flow must be diverted in some manner around or through the new plant until final transition to the new plant. It is likely that an additional circulating water line will be needed to supply the additional flow for the 50% uprate. Addition of a parallel path will be difficult for a plant arranged like Comanche Peak where the lines pass under one unit to get to the second unit. Plant specific analysis of the ability of the piping to take additional flow without addition of a line will be necessary.

An alternative to moving the existing circulating water lines out side the boundary of the new turbine building would be to build the turbine hall beyond the existing circulating water lines. This would cause the main steam and feedwater lines to be much longer and probably would require larger diameters to prevent excessive pressure drops. Long-term energy losses would have to be considered to determine the option that made economic sense for the site.

Each plant site has buildings and tanks in the vicinity of where the new turbine could be placed. Some have warehouses, some have security buildings. Each will require these buildings to be relocated prior to the start of construction of the new turbine generator.

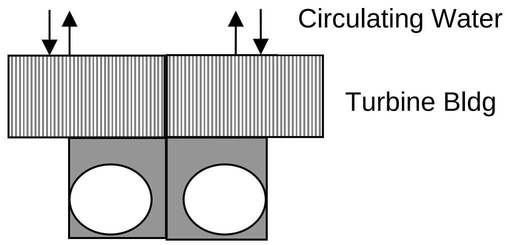

Figure 2. Braidwood, Byron, Vogtle Layout

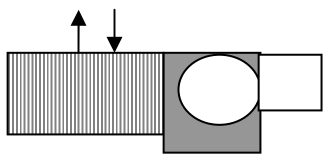

Figure 3. Calloway, Wolf Creek Layout

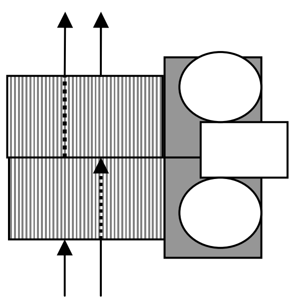

Figure 4. Comanche Peak Layout

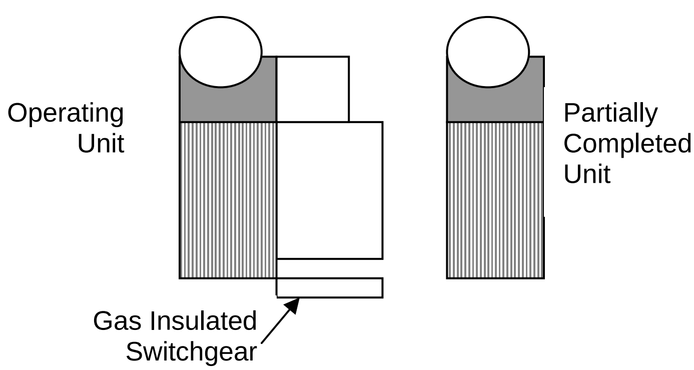

Figure 5. Seabrook Layout

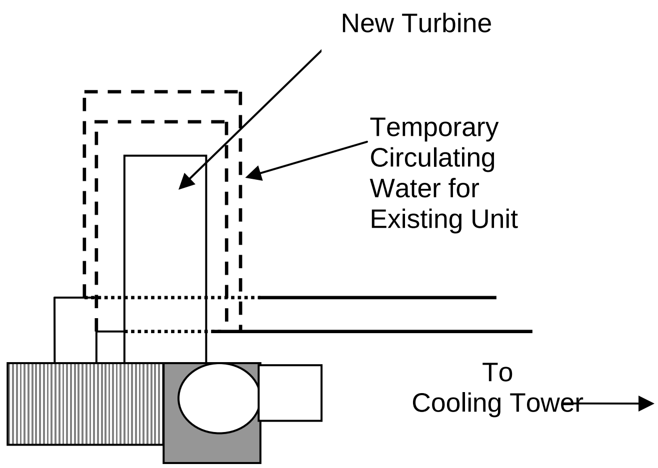

Figure 6. Calloway Circulating Water Reroute (Rerouting will be plant specific)

12 GENERIC CONSIDERATIONS

Auxiliary Feedwater System

The auxiliary feedwater system provides core cooling via the steam generator when the turbine is not in service. There are three 100% pumps: 2 electric driven, 1 steam driven. Because the heat removal requirements are likely to be 50% greater, the flow from each of these pumps will have to be increased by 50% to provide cooling. The pumps, motors and steam turbine will have to be replaced. Cables to the motors will have to be replaced due to higher current requirements.

Fuel Handling and Fuel Pool Concerns

The fuel pool must be partially revised with new racks that will accommodate the new fuel elements. The length and basic configuration will remain the same (Westinghouse must confirm). However, the decay heat and radioactivity levels are likely to be higher. The racks may have to be reconfigured or modified to address these changes. If new racks are necessary, the area with new racks will have to have at least enough spaces for one full core plus enough for 1 refueling or more. A larger capacity than that is desirable to continue to accommodate refuelings after the uprate. There must be at least enough spaces of the original configuration to allow off-load of the old core. An eventual concern will be development of dry storage capability for the new fuel configuration. Fuel must be stored in the fuel pool for a significant period (up to 10 years) before it can be placed in dry storage facilities. Accordingly, the pool must be able to hold the full offload at the time of uprate, have space for a full core offload, and be able to store more frequent offloads because of the shorter refueling cycle, and be able to hold the offloads for up to 10 years.

Given the basic fuel dimensions will remain the same, the up-enders and transfer mechanism will continue to be used.

Subsequent to use, the new fuel is likely to be 50% more radioactive than the old style bundle and is likely to have 50% more decay heat. The dose rate around the fuel transfer tube will have to be reviewed to determine if additional shielding is needed. The fuel pool dose rate calculations will have to be reviewed and the fuel pool heat removal capability will have to be reviewed.

The new fuel will have higher residual heat at offload. The spent fuel cooling system may have to be upgraded to accommodate the additional heat load during and following a refueling, especially in the case where a full core off load is required. In addition, the time to boil calculations will have to be reperformed to determine if adequate time to respond is available should fuel pool cooling be lost. Analyses will also be needed for a dropped fuel accident, an assembly stuck in the transfer tube, and the effects of a design basis missile (or dropped object) striking the fuel pool.

Removal of Reactor Internals

The reactor internals are designed to be removed and temporarily stored under water during an outage. However, the internals must be removed from the reactor building as early in the transition outage as possible. Means of removal must be carefully considered. Surface decontamination is possible, but the materials will be highly radioactive. It is not clear whether a shield can be constructed that can contain the internals and still be lifted using the polar crane. The shine during removal from the reactor building may require shutdown of containment operations during the period.

Supports, Snubbers and Restraints

Changes in equipment and piping dimensions, mass, center of gravity and energy level will require design of new or modified supports. Changes in routing and size of piping, loading of cable trays where higher power components may require cable size increases, and other changes that affect the normal operational stresses or post accident loadings will require design and analysis of new support systems. Experience shows that the installation and inspection of such supports, including the potential for increasing base plate loading and base plate modification is a time consuming activity subject to considerable rework. Time will be required for the inspection and determination of appropriate clearances at cold, intermediate and hot conditions, and for reinspection after transient testing, which loads the support system. This work is generally in series with moving to successive stages of operation. Because of such activities, the use of new construction startup estimates as a model for recovery from this plant upgrade are appropriate.

Control Room and Instrument and Control

For a number of reasons, the control room must be digital before conversion to the uprate. First, integration of a new control system in 2015 with a bench board based control room would be impractical due to space and inordinate human factors problems. Given a digital control room, conversion of the control room for the BOP and reactor systems will be much easier. In addition, the plant simulator can be modified reasonably easily as well.

The use of digital technology for the control room and the overall control and instrumentation system will also ease startup testing, in that smart components and systems will be able to determine the correctness of cable connections and the basic health and setup of many of the control and instrumentation components. Given an existing digital control room, the reuse of the existing base control room equipment and consoles is likely.

Control room habitability will have to be reassessed prior to the uprate outage due to the higher post-accident source term that is likely to be associated with the new core.

Main Circulating Water System

As discuss earlier, for nearly all of the plants under consideration, the optimal location of the new turbine plant will likely be on top of the existing circulating water lines. The construction of the new plant on top of the existing lines would be impractical and likely put the operating plant at risk. Relocation of the lines around the site of the new turbine plant is likely to be required. Section of the relocated lines would also have to be strengthened to accommodate the construction loads from the new plant. The installation of the lines would begin in advance of the third refueling outage prior to the main uprate outage with the connections of the temporary lines to the main circulating water lines during the third refueling outage prior to the main uprate. At the same, time that the circulating water system is being transferred, any safety-related piping and tanks in the area for construction of the new turbine would be replaced/relocated and reconnected.

The main circulating water system pressure can likely be increased to provide adequate flow for the uprate through installation of additional pumps or replacement of the existing pumps. However, additional intake structure equipment (trash racks etc) will be needed to accommodate the additional flow. In addition, if a cooling tower is needed to accommodate the additional rejected heat, which is highly likely, the portion of the flow to the new cooling tower will require a booster pump to move the water to the cooling tower bay. The metal piping interfaces of the concrete piping system with the pump system will have to be upgraded to take into account the higher flow. Depending on the turbine option selected (new 1800 MWe turbine versus old turbine plus a 600 MWe turbine), the use of the existing lines or the addition of parallel lines may be clear. For example, the lines to the old turbine may have to be permanently relocated, and a new set of pumps and new lines run to the new turbine. If the full flow is going to new 1800 MWe turbine generator, the old lines could be used if adequate flow can be established to remove the heat.

At the main uprate outage, the temporary circulating water lines would be transferred permanently to the condenser for the new turbine as appropriate.

Residual Heat Removal and Containment Cooling

The residual heat removal is expected to be adequate to cover the additional heat load for normal and accident conditions. Containment coolers also have adequate capacity. Intermediate pressure safety injection will increase significantly with the flow having to increase from 650 gpm to 1500 gpm. The shutoff head can be lower; however, the power is expected to increase by a factor of 2.5.

Component Cooling

Two horizontal component cooling water heat exchangers are used in each plant. Additional component cooling water is likely to be needed. Plate and frame heat exchangers could be used to replace the component cooling water heat exchanges to provide additional exchange surface. Component cooling pumps and motors are likely to have to be replaced to provide additional capacity.

Ultimate Heat Sink

The ultimate heat sink ponds at the site vary in type and style. Each is a seismically qualified impoundment of water. Some are sections of a man made lake with a seismically qualified dam.

Some are separate ponds with sprays. The heat sink capacity should be sufficient. However, the need for makeup water due to higher levels of evaporation will need to be verified.

13 OUTAGE TASKS

Table 8 lists the basic outage activities that must be performed starting up to three outages before the transition outage. The table assumes that construction of the new turbine and physical plant has proceeded to the point where all activities possible that do not require the plant to be out of service have been completed. The remaining work requires interruption of the steam and feed lines or requires the fuel to be off loaded to allow uprate activities to begin.

Table 8. Basic Order of Activities

Action (Timing and Event)	Main Concern	Comment
Pre-Cursors	• Dry Storage Casks • Digital Control Room • Outbuilding and Tank Relocation • Construction of Construction offices and warehousing facilities	• Assures adequate fuel offload capability • Necessary for transition
Outage -3		
Re-route Circulating Water Pipes	Install rerouting prior to -3 Outage, connect during outage.	
Reconnect relocated or replaced tanks.	Connect any relocation/new operationally/safety important tanks to operating unit.	
Outage -2		
Prep Work as needed		
Core offload, core barrel removal and support structure removal/replacement	Make mounting and fit-up measurements to allow final fit-up machining	Necessary to make final installation quick (Note: Some activities requiring fuel to be off loaded may be implemented if the outage schedule permits.
Upgrade transmission breakers requiring unit outage as applicable. Upgrade buses.	At minimum, inspect substation. Begin upgrade if required	
Outage -1		
Prep Work as needed		
Fit-up measurements of core items if not done in -2 Outage		
Continue upgrade transmission breakers requiring unit outage as applicable. Upgrade buses.		
Prior to Transition Outage	Re-arrange fuel pool, install racks for new fuel, and off-load old fuel as possible to dry storage.	
Transition Outage (In-containment)		
Reactor Cavity and Piping Flush	Reduce radioactivity as much as possible.	

Action (Timing and Event)	Main Concern	Comment
Containment and Auxiliary Building Decontamination	Eliminate radiation protection areas to the extent practical to allow work to proceed as rapidly as possible.	
Head Removal and Cleaning		
Head Removal from Building	Significant event	
Core off-load		
Core Barrel and Support Structure Removal and Cleaning		
Core Barrel and Support Structure Removal from Building	Significant event. Highly radioactive. May shutdown all work in containment for the duration of the transfer to outside of containment.	
Cleanup reactor bottom penetration welds	Not required by uprate, but appears prudent	
Inspect Interior of Reactor Vessel	Not required by uprate, but appears prudent	
Mainsteam Line Replacement and New Bracing		
Pressurizer Replacement	Higher power likely. Cable and penetration likely to need replacement	
Reactor Pump Removal and Replacement	Cable for reactor pump motor and the associated electrical penetration will have to be replaced due to higher normal current and fault current	
Steam Generators	Remove and Replace	
Transition Outage (Outside-containment)		
Remove old steam lines, connect new		
Replace MSIVs		
Remove old feedwater lines, connect new		
Install common condensate surge tank	Allows single inlet to feedwater pumps and eliminates disparate feedwater pump control issue	The condensate pumps from the two turbine systems will feed a common surge tank that is the suction for a single feedwater system.
Uprate feedwater pumps		
Connect Control Room to new instrumentation	Must follow offload of fuel.	Temporary fuel pool monitoring system may be needed with Main Control Room disrupted
Replace outside containment power cables as needed		
Disconnect old main transformer. Connect new main transformer		
Disconnect circulating water from old unit. Connect to new unit.		
Upgrade circulating water pumps or add new circulating water pumps		

Action (Timing and Event)	Main Concern	Comment
Change safety relief valve orifices and test valves		
Upgrade Auxiliary Feedwater electric and steam driven pumps		

14 STARTUP ISSUES

Prior to commencing startup activities, the construction areas must be returned to plant operations control. This will require extensive inspection and walkdown of areas where construction activity occurred to assure that the plant matches the 'as-designed" condition, and confirmation that equipment is operable and instrumentation is functional. Turnover and acceptance by the operators will reinstate the formal change and modification process and end the construction phase of the transition outage.

The magnitude of changes in the primary and secondary systems will make the startup testing process closer to the startup for a new construction plant than for a typical modification outage. A review of the NRC inspection procedure, IP 50001, [5] gives a view of the kinds of checks that are expected for just the steam generators. The following items were taken from IP 50001:

> **"02.04 Post-installation Verification and Testing Inspections**
>
> Conduct steam generator (SG) post-installation verification and testing inspections in accordance with the inspection plan. Perform selective inspections, consistent with the safety significance and inspection resources, of the following areas:
>
> 1 Containment testing, as applicable.
> 2 The licensee's post-installation inspections and verifications program and its implementation.
> 3 The conduct of reactor coolant system leakage testing and review the test results.
> 4 The conduct of the SG secondary side leakage testing and review the test results.
> 5 Calibration and testing of instrumentation affected by SG replacement.
> 6 The procedures for equipment performance testing required to confirm the design and to establish baseline measurements and the conduct of testing.
> 7 Pre-service inspection of new welds.
> 8 The impact of changes in mass and center of gravity of the new steam generator on the seismic analysis for the containment structure, pipe stress analysis, and other safety systems and components
> 9 The effect of the steam generator and related design changes on transient and accident analyses including tube ruptures
> 10 The cumulative and synergistic effects, if any, of the steam generator, related design changes, and other modifications completed during the outage on transient and accident analyses
> 11 Adherence to and reconciliation of code requirements
> 12 Compliance with regulatory requirements including the incorporation of in-service inspection requirements of 10CFR 50.55a (g)

The licensee's post-installation verification and testing program should verify that modifications are completed in accordance with the design; that drawings, procedures, and training have been updated as appropriate; that post-installation walkdowns and inspections are performed to ensure equipment is restored and temporary services are removed; that equipment cleanliness has been verified; that pre-service inspection of welds to establish baseline data are performed; and that deficiencies are properly dispositioned. Verify that changes in performance of the SGs and in its associated parameters, such as flow rates, pressures, and temperatures are appropriately included in design documents and plant procedures."

The most likely criteria to be applied to the overall pre-startup test program from the NRC perspective (in addition to the various Inspection Procedures that would apply to each system or subsystem) are described in Regulatory Guide 1.68 Rev. 2. In brief, the scope of this Regulatory Guide can be summarized in this excerpt:

> "Initial startup testing, as used in this guide, consists of those test activities scheduled to be performed during and following fuel loading. These activities include fuel loading, pre-critical tests, initial criticality, low-power tests, and power-ascension tests that confirm the design bases and demonstrate, to the extent practical, that the plant will operate in accordance with design and is capable of responding as designed to anticipated transients and postulated accidents as specified in the SAR.
>
> The initial test program should be designed to demonstrate the performance of structures, systems, components, and design features that will be used during normal operations of the facility and also demonstrate the performance of standby systems and features that must function to maintain the plant in a safe condition in the event of malfunctions or accidents. It is very important that the sequence of startup tests be ordered so that the safety of the plant is never totally dependent on the performance of untested structures, systems, and components.
>
> Sufficient time should be scheduled to perform orderly and comprehensive testing. The applicant's schedules for conducting the preoperational phase and the initial startup phase would provide for a minimum time of approximately 9 months and 3 months, respectively."

Although this regulatory guide estimates testing from the 5% license to commercial operation to take three months, experience has shown that such testing takes considerably longer. The best six plants in the 1983-1987 period ranged from 124 days to 190 days for 5% license to commercial operation with an average of 160 days. Given the nature of the modifications and first of a kind application of the reactor coolant pump, core, steam generator, turbine and generator designs, using this startup experience is valid for estimating the duration of the power escalation process.

Figure 7 shows the expected startup and power ascension schedule that is likely to apply to an ultra uprate. While the unit would return to operation about seven months after completion of construction, power ascension is likely to take almost 6 months more. During that time, the unit may be operating at partial power or be offline for corrective work. At a point midway into power ascension, the unit will begin generating power exceeding its original rating; however, full 150% power is unlikely to be generated until very near the end of power ascension.

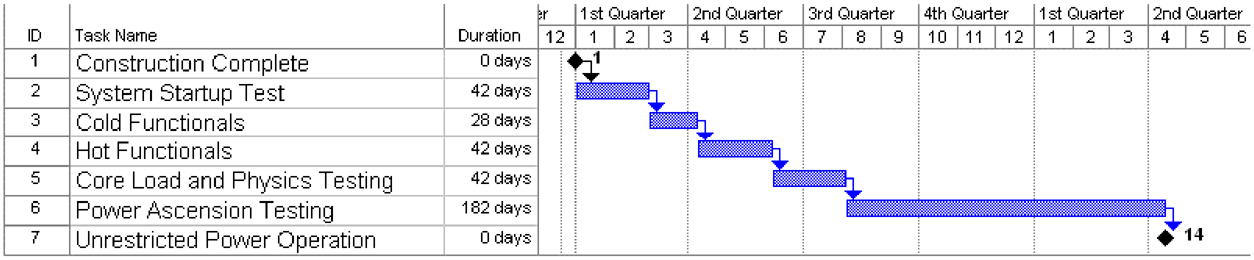

Figure 7. Estimated Startup and Power Ascension Schedule

15 COSTS AND PRIORITY OF ISSUES

Site specific costs will be significantly different for each site. The cost of upgrading the surrounding transmission system will be site dependent as well as option dependent. Each site is likely to require at least one more transmission line between it and an adjacent transmission substation. If an 1800 MWe generator is selected as an option, the local circuit breakers and buses will have to be upgraded to higher ratings and surrounding lines and substations are likely to require uprating to accommodate the higher normal loads and fault currents. If two smaller generators are used instead, the extent of transmission system upgrade will be much smaller. The cost of additional transmission capacity is likely to be unique to the uprate, in that construction of an alternate unit may allow options for placement on the transmission system where less expensive changes are necessary to allow the unit to be connected to the grid. Per Reference 2, the average cost per mile of 500 kV transmission is $600,000/mile (1993$).

Expected Cost for Comparable Generation

The largest nuclear unit in the world (1714 MWe) is currently under construction (Olkiluoto 3) in Finland for 3 billion euros. At the current exchange rate, the cost of construction will be $3.6 billion. Per Reference [4], the expected cost for the construction of an AP-1000, 1000 MWe plant ranges from $1200/kW to $2000/kW, or $1.2 to $2 billion. The economies of scale indicates that the cost of a plant increases at a 0.7 power. Working backwards

$$(600/1000)^{0.7}\ (\mathrm{Cost}_{1000}) = \mathrm{Cost}_{600}$$

and

$$(600/1714)^{0.7}\ (\mathrm{Cost}_{1714}) = \mathrm{Cost}_{600}$$

Accordingly, the range of costs for construction of a 600 MWe plant is as follows:

Olkiluoto 3 based:	$1.7 billion
AP-1000 - low:	$840 million
AP-1000 - high:	$1.4 billion

The range of the percentage of cost associated with the BOP systems is 20 to 40% depending on the nature of the turbine building (e.g., open frame versus closed building). Accordingly, the cost of the BOP for a 600 MWe turbine/generators is in the range of $277 to $561 million.

Uprate Issues, Priority and Costs

To allow an ultra-uprate to proceed, a number of generic and plant specific issues must be considered and resolved. Table 9 lists issues of high importance that must be considered and resolved but that are outside the scope of this report to address in detail.

Issue	Resolution Statement	Comment	Importance (10 high)
Licensing basis must be resolved (what licensing basis applies to old and uprated sections of the plant)	Must be resolved with NRC prior to start of design of changes		10
The safety analysis report for the uprate must be prepared and accepted by the NRC		Safety analysis must be accepted before significant construction activities begin	10
Permits for additional cooling water and need for installation of cooling towers	Must be resolved with state and federal governments	Common to any new plant construction.	10
Additional transmission may be needed to allow power transfer	All plants will need additional transmission lines to cover the contingency of loss of one line. Additional transmission may be necessary to transfer power under local low load conditions	Plant specific issue. Costs will vary significantly by location.	10
Aging of retained structures, systems, and components	Retained SSCs should be reviewed to determine if refurbishment/replacement is prudent	Plant is likely to be 25 or more years old at time of uprate	8
Dry fuel storage is assumed to be licensed for the site	To allow transfer of old core from reactor and have sufficient core space in the fuel pool for the new fuel, old fuel will have to be transferred to dry storage	Most plants are likely to have dry fuel storage plans implemented by time of uprate.	8
The Control Room is assumed to have been converted to digital based	Implementation of uprate requires a digital control room	Plants will have been converted to digital control by time of implementation of uprates	8

Table 9. High Importance Issues to Be Resolved that Are Outside Scope of This Report

A number of assumptions exist that could increase costs if they do not hold. These are:

1. The peak pressure and temperature for design bases accident conditions will not increase beyond containment capability limits. If this assumption does not hold modifications to containment would be necessary that have not been considered here.
2. Fuel length and girth will not increase significantly such that current fuel handling equipment and fuel pool water depth are adequate.
3. While steam lines must be increased in size to reduce pressure drop at turbine inlet, the main steam and feedwater penetration size will remain the same. Concrete coolers may have to be added.

Table 11 provides a listing of issues that have high impact on cost that are unique to the ultra-uprate. These costs would not occur for either a new nuclear plant or a plant with any other fuel.

As can be seen from the table, the costs of the lengths of the transition outage and pre-transition outages are critical. Any reduction in the length of these outages will significantly aid the case for ultra uprates. The reduction of capacity factor from having to implement a 12-month refueling cycle also has a significant effect. The 12-month refuel cycle effect costs shown are the present value costs for a 20 year period. The key factors in these calculations are the cost of money, the inflation rate, and the cost of replacement power.

Issue	Comment	Low Value	High Value
Transition Outage Length	The length of the transition outage must be tightly controlled. An optimistic transition outage is approximately 12 months for a 50% uprate. A 25% uprate may take as little as 9 months due to somewhat more limited testing and startup.	$137[4]	$365[5]
12 Month Refueling Cycle	Because of higher energy density, the refueling cycle after uprate will be 12 months. The present value cost of the more frequent outages is presented	$63[6]	$239
Preparatory Outage 1 Length	30 additional days for underground piping rearrangements	$15	$30
Preparatory Outage 2 Length	20 additional days for prep work	$10	$20
Radioactive work logistics	A large volume of radioactive equipment must be removed and stored.	$10	$20
Construction will be under nuclear plant security controls	Much of the construction will be inside operating plant boundaries and post- 9/11 security requirements will apply	$5	$20
Outage Planning	To assure shortest possible outage additional outage planners will be needed for a period of 3 or more years	$12	$25
Total		$252	$719

Table 10. Costs Unique to an Ultra-Uprate (Millions)

Table 11 provides the costs of the physical implementation of the uprate. These costs are based on installation of a new 600 MWe turbine generator in parallel with the existing generator.

4 Low outage costs are based on $500,000/ day replacement cost
5 High outage costs are based on $1,000,000/day replacement cost
6 Present value high and low costs are explained in Section 3

Issue	Comment	Low Value	High Value
Relocation of Existing Circulating Water Lines and Underground Equipment	Circulating Water Lines must be relocated at least 2 outages before transition to allow new turbine/generator to be built	$10	$20
New Turbine/ Generator	600 MWe Turbine/generator and all auxiliary systems and main transformer	$300	$600
Additional intake structure, circulation water pump, additional circulating water piping to new turbine/generator	Included in above item	-	-
Transmission Substation - Bus extension, additional circuit breakers, additional startup transformer	Included in new Turbine/Generator cost	-	-
Medium Voltage Substation upgrades including MCCs and Load Centers	Upgrade to capacities required due to increased pump loads.	$20	$40
Control Room Integration	Software and interface modification for new turbine/generator and overall modified system (includes cost for updating existing digital simulator)	$7	$14
Total		$337	$674

Table 11. Costs of Physical Implementation of Ultra-Uprate - Secondary Plant

Table 12 presents the costs associated with the replacement of the reactor head, internals, pressurizer, reactor coolant pumps, and steam generators.

Issue	Comment	Low Value	High Value
Replace reactor coolant pumps and motors		$70	$90
Replace RCP Cables and RCP and pressurizer heater electrical penetrations	13 kV cable and penetrations must be replaced for RCP. Increased capacity cabling and penetrations needed for pressurizer heaters.	$6	$12
Replace reactor head, core support, pressurizer, and steam generators,		$450	$600
Replace main steam piping and penetrations, upgrade relief valves		$20	$40
Replace MSIVs		$10	$16
Upgrade pipe supports for steam and feedwater lines		$5	$10
Increase Auxiliary Feedwater Capacity		$5	$10
Add common condensate surge/de-aerator tank for feedwater pump inlet	Eliminates control problem between disparate feedwater pump systems	$8	$12
New Main Steam Isolation Valves		$12	$24
Total		$586	$814

Table 12. Nuclear System and Steam Generation Costs

Table 13 provides the costs for upgrading the nuclear safety systems.

Issue	Comment	Low Value	High Value
Environmental Qualification	Long-term thermal energy will increase. Environmental qualification of components will require upgrade	$0.5	$5
Additional Emergency Diesel and Switchgear		$10	$25
Ultimate heat sink capacity increase		$5	$10
Intermediate pressure injection upgrades		$10	$20
Low pressure injection upgrades		$12	$30
Upgraded containment coolers		$3	$6
Rerack and rearrange fuel pool; upgrade fuel pool cooling		$12	$25
Total		$53	$121

Table 13. Safety System Upgrade Costs

Table 14 provides the summary of costs for the overall ultra-uprate

Cost Area	Low	High
Ultra Uprate Unique	$252	$719
Secondary Plant	$337	$674
Nuclear and Steam System	$586	$814
Safety Systems	$53	$121
Total	$1,228	$2,328

Table 14. Summary of Costs for 50% Ultra-Uprate (Millions)

Per Table 13, the costs could range from $1.2 billion to $2.3 billion for a 50% uprate. As described in the previous section, the cost of a new 600 MWe nuclear plant could range from $840 million to $1.7 billion, which does not agree favorably with the Table 13 results.

The greatest drivers in the cost of the uprate that are beyond the normal costs of construction are:

- Costs unique to Ultra Uprate: $252 to $719 million (Likely $400 to 600 million)
  The two largest drivers in this set are:
    - the preparatory and transition outages and
    - the lost revenue of a 12 month refueling cycle.
- Costs associated with removal of Reactor and Steam System equipment (Head, core support, Reactor coolant pumps, pressurizer, steam piping): $100 to $180 million.
- Costs of rearranging and relocating existing piping and equipment to allow construction: $15 to $30 million.

The summation of the costs equal $367 to $929 million, which put the ultra uprate at a distinct disadvantage with comparison to new construction. Deducting these costs unique to Ultra Uprate from the low and high summary costs yields, a lower estimate bound of $830 million and a high estimate bound of $1.37 billion, which are slightly favorable in comparison to building a new unit.

25% Uprate Cost Considerations

Building a new 25% capacity (300 MWe) turbine generator will cost between $200 and $440 million. There will be a difficult control problem paralleling a 1200 MWe machine with a 300 MWe with respect to feedwater. For a small additional cost the new turbine could be slightly oversized to all operation margins to exist on the original turbine generator, which should increase its longevity. The building of a new separate will require additional high voltage substation breakers to be installed. As shown in Table 15, the cost of a 25% uprate is expected to be between $1.02 billion and $1.97 billion. There is no change in the expected costs unique to uprate. Elimination of the removal and replacement of the reactor coolant pumps will have minimal effect on the length of the transfer outage and may reduce the outage length by two weeks. Startup testing may be shorter tending to shorten the outage. Accordingly, 25% uprate costs may approach lower cost estimates because of the large effect of outage length. The present value of the reduction of capacity factor may also be lower if refueling cycles for 25% uprates are 15 months rather than 12.

Element	Low Estimate	High Estimate
Cost of 50% Uprate	$1,145	$2,230
Less		
600 MWe Turbine/generator and all auxiliary systems and main transformer	$300	$600
Reactor Coolant Pumps and Cabling	$23	$56
Plus		
Cost of 300 MWe Turbine/Generator	$200	$440
Cost for 300 MWe Uprate	$1,022	$1,974

Table 15. Expected costs of 25% Uprate ($ million)

Comparison of Major Options for 50% Uprate

Table 16 provides a comparison of the options for the turbine/generator. These are

- Retain the existing 1200 MWe turbine; add a 600 MWe turbine/generator
- Replace original turbine with an 1800 MWe turbine generator
  Main drawback: Major overhaul of transmission system in and around the plant highly likely because normal breaker, line and bus ratings will need to be increased to 3000 amperes. Generator would be largest built and transported to date.
- Replace original turbine with 1800 MWe system with two 900 MWe generators in series or separate high and low pressure shafts and generators.
  Main drawback: Unusual configurations

The first option is likely to allow full output from the plant and would not require construction of generator, transformer and breaker components of sizes previously not attempted or transported. While the configuration of the equipment would be unusual, the logistics and construction issues should be much less difficult.

The construction of a new 1800 MWe turbine/generator would eliminate any value to the existing 1200 MWe turbine/generator. A totally new turbine/generator would eliminate concerns about any aging sections of the existing turbine/generator, but at a significant cost. Table 16 includes comparison to an alternate unit that is either nuclear or fossil powered.

The primary advantage of a full size 1800 MWe turbine/generator is that one integrated system results. With the add-on of a 600 MWe turbine/generator to the existing turbine/generator, two disparate turbine/generators will be operated in parallel, making control and operations more difficult. The greatest disadvantage to the full size 1800 MWe turbine/generator is the additional cost, which could be $760 million more than a 600 MWe add-on turbine/generator.

Table 16. Comparison of Turbine/Generator Options

Issue	Original Turbine Plus 600 MWe Turbine	Full 1800 MWe Turbine	Alternate 600 MWe Plant	Comment
Cost	Lowest Cost	Highest Cost	Cost of construction low; fuel costs higher	
Control of System	Dissimilar size turbines likely to cause control problems with balancing feedwater flow etc at anything but full output	Integrated system, control should not be a problem; if two generators are used some additional sophistication in startup may be needed.	Integrated system; no issue exists	
Transmission	Additional line or lines will be needed.	Additional line or lines will be needed. Transmission breakers will need to be uprated for 3000 amp capability to allow 1800 MWe output on a 500 kV. Plants on a 345 kV system will not be able to have an 1800 MWe capacity due to current limitations even with a 3000 amp circuit breaker. Resolution: Use two, 900 MWe generators on the same shaft or separate the high pressure turbine from the low pressure turbines and power separate generators to eliminate breaker rating limitation.	Plant could be located elsewhere on the transmission system where additional lines would not be needed. However, a substation would have to be built.	1800 MWe unit would only work at 500 kV sites with local substation and transmission system upgrades. 600 MWe turbine addition would require upgrades but not as extensive. 600 MWe alternate plant likely not require transmission upgrades but would require a substation (subtract substation cost in comparison of cost)
Above and Underground Conflicts	Above ground buildings and tanks will have to be relocated. Piping, especially circulating water piping is likely to have to be rerouted around the new turbine site to allow construction to proceed. Relocation efforts need to be integrated into "-2 refueling outage."	Same as 600 MWe turbine case	Site likely to not have useful facilities underground or above ground. Site preparation costs associated with relocation are not likely.	
Cooling Water	Additional cooling capacity is	Same	Cooling towers are likely for	Similar cost for addition

Issue	Original Turbine Plus 600 MWe Turbine	Full 1800 MWe Turbine	Alternate 600 MWe Plant	Comment
Source	needed and will require cooling towers at all sites except Seabrook.		fossil plant	of cooling tower needed for any source of cooling water
Circulating Water Pumps, intake structure	• 50% more circulating water will be needed. • Larger pumps will be necessary to support additional flow. • The bulk of the piping may be adequate for additional flow, but site specific design calculations will be necessary. • For plants not having cooling towers, booster pumps will be needed to increase pressure for 600 MWe addition to get water to the cooling tower hot basin elevation • Intake structure modification needed to provide trash rack system for new flow (trash rack system needed for flow from cooling tower; this system may not be as extensive as that for raw river or lake water)	Same	Similar issues Total circulating water piping system needed.	Intake structure modification may cost more than adding an intake structure.
Control of Heavy Loads	Heavy loads will have to be carefully controlled over underground facilities. Cranes that will not topple must be used near reactor and fuel buildings	Same	Not a problem	

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A Transmission Analysis for Uprate Plants

The following report, *Nuclear Plant Uprating Screening Study*, evaluates the possible interactions between an uprated 1800 MWe nuclear power plant and the transmission system.

Nuclear Plant Uprating

Screening Study

Final Report, April 16, 2004

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CONTENTS

1 SUMMARY

This report describes a screening study of candidate nuclear plants for a 50% uprate in output power. The analysis was based on several data sources (see Section 3) as well as actual simulation of the total Eastern Interconnection System.

Based on the analyses performed, the following tentative conclusions can be made. Definitive recommendations can only be made after thorough investigations are performed.

- The existing transmission capacities at the generation stations for most of the selected nuclear power plants (except for Byron nuclear power plant) may be sufficient for supporting the 50 % uprating according to the data available for this study <u>if all of the transformers/lines are in service</u>.

- For the Byron nuclear power plant, it is necessary to upgrade the transformers and transmission lines because the N-1[1] operating requirements are not met even if all of the related transformers / lines are in service after the 50 % uprating of the power plant. The transmission enhancements should meet the NERC operating standards while allowing for the maintenance requirements of the transformers and transmission lines directly connecting to the nuclear power plants.

- For Byron (1&2), Wolf Creek, and Comanche Peak (1&2), with 50% uprates, and with one line out of service from the corresponding plant, the adjacent lines would be loaded to levels to above 85% of the static ratings. Given the approximate nature of this study, any loading above 85% warrants further study.

- A potential reactive power supply and voltage regulation problem has been identified at the Callaway plant when the nuclear generator is not in operation. The study did not identify other voltage control issues with the selected plants. Uprating the plants will actually help to negate voltage collapse problems in their immediate areas provided that the uprating includes addition of a second turbine generator. If the uprating includes operating the existing electric generator at higher loading, there may not be sufficient capability to supply the needed reactive power.

[1] In a contingency analysis, engineers present a model of the electrical system with hypothetical demand conditions and a base case of operating generators and lines. Large generators and major lines are then taken off line one at a time to mimic unplanned outages. This is called an N-1 contingency analysis: all but 1 of the n pieces of major equipment in the electrical system is assumed to operate normally.

- In a deregulated environment, transmission networks have loading patterns much different than they were designed to accommodate. This is particularly true of networks in the vicinity of nuclear plants. When the plants are not in operation, the transmission lines may be highly loaded transporting power from other sources. Providing reactive power supply and voltage regulation during these times may become necessary to maintain acceptable system voltage to operate the plant auxiliary equipment. This concern is most applicable to the Callaway, Wolf Creek and Seabrook stations since they are single unit plants. If these plants are selected for uprating, a careful study should be made to quantify the need for reactive power for operating the transmission network when the reactor is not operating.

- A consideration in determining which nuclear plant may be most suitable for a 50% uprate is the percentage of time the transmission network can reliably accept full power from the plant. If this plant is large compared to other plants, it is likely that its output will have to be reduced under light load conditions to have sufficient spinning reserve to protect from the loss of this source. It is more difficult to operate a large nuclear plant in a load following mode than other types of plants. This issue seems to be of more concern if the Wolf Creek, Callaway or Vogtle plants are considered for uprating.

To a lesser extent, this effort looked at the economic merits of uprating these plants based on prevailing power production costs in the areas which the plants reside (see Section 6). It also raised the issue that providing network security may require operating plants at some of the locations at lower power levels during times when system load is low.

It is difficult in an initial screening study to provide precise conclusions. Rather many of the considerations result in a relative figure of merit. This figure of merit would be a ranking from 1 to 5 with the lower number being a higher ranking. Table 1 depicts the result of this ranking exercise and indicates the ranking of these locations from a technical standpoint.

From Table 1, it can be concluded that the most logical uprate potential is at the Seabrook Nuclear Station. This is followed by Braidwood. Of course, much more detailed analysis will be needed for a final selection.

Table 1: Relative Plant Rankings
1= Best; 5=Worst; Lowest Total is "best"

Unit	Transmission System Capacity	Area Production Costs	Value of Voltage Support	Likelihood of Curtailment During Low System Load	Total Ranking
Braidwood 1	2	1	2	1	**6**
Braidwood 2	2	1	2	1	**6**
Byron 1	5	1	1	1	8
Byron 2	5	1	1	1	8
Callaway	2	2	1	2	7
Wolf Creek	3	2	1	2	8
Comanche Peak 1	4	2	2	1	9
Comanche Peak 2	5	2	2	1	10
Seabrook	1	1	1	1	**4**
Vogtle 1	2	2	2	2	8
Vogtle 2	2	2	2	2	8

2 INTRODUCTION

The objective of this project was to produce an initial screening for 11 nuclear plants from seven locations, see Table 2, for their suitability for a 50% uprating based on the limitations of the electrical transmission grid. Figure 1 shows the NERC region that these plants are located in. Note the colors of the cells of Table 2 correspond to the color of the region in Figure 1.

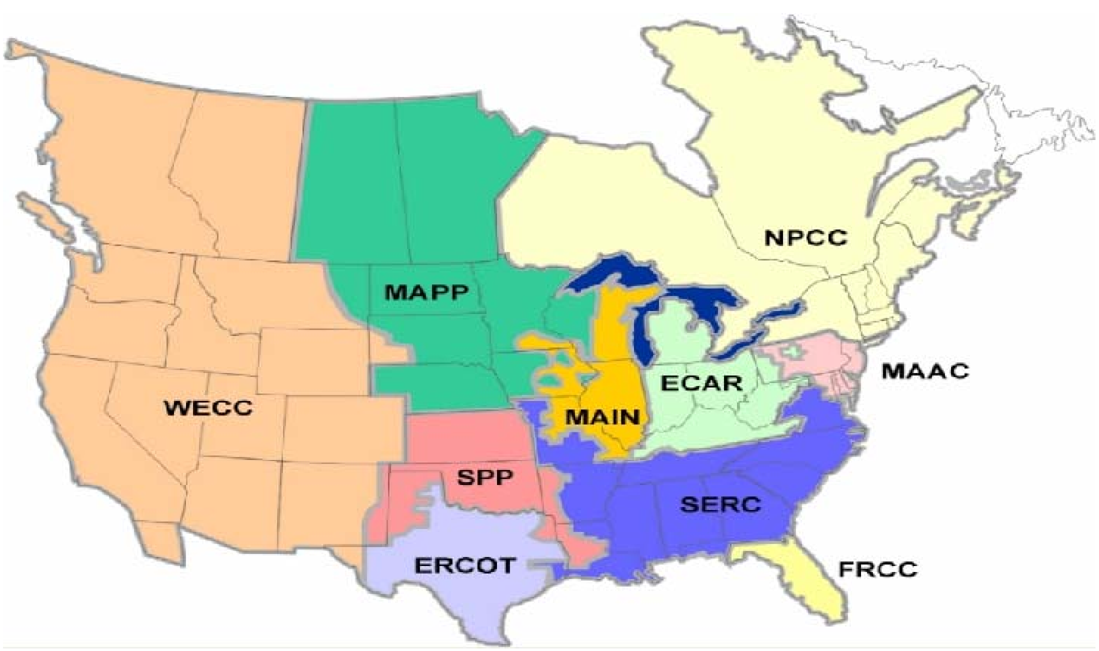
The determination of the upgrade suitability is a very complex task requiring comprehensive assessments of the transmission grid, conditions of existing plant components, various types of protection systems for nuclear power plants, and factoring in different requirements such as regulation, seismic, environmental.

A screening procedure was developed for assessing the suitability for a 50 % uprating based on the transmission limitation. A preliminary screening study was performed using this procedure and the various types of information for the selected nuclear sites units as shown in this report.

Table 2: Candidate Plants and Associated NERC Region
(Acronyms are defined in Appendix E)

Unit	NERC Region	Nameplate Capacity, MW	Summer Capacity, MW	Location
Braidwood 1	MAIN	1125	1185	Braidwood, IL
Braidwood 2	MAIN	1125	1177	Braidwood, IL
Byron 1	MAIN	1225	1194	Byron, IL
Byron 2	MAIN	1225	1162	Byron, IL
Callaway	MAIN	1235	1144	Fulton, MO
Wolf Creek	SPP	1236	1170	Burlington, KS
Comanche Peak 1	ERCOT	1215	1084	Glen Rose, TX
Comanche Peak 2	ERCOT	1215	1124	Glen Rose, TX
Seabrook	NPCC	1242	1161	Seabrook, NH
Vogtle 1	SERC	1160	1148	Waynesboro, GA
Vogtle 2	SERC	1160	1149	Waynesboro, GA

Figure 1: NERC Regions



3 INFORMATION SOURCES

The preliminary screening study is based on the following information from different sources:

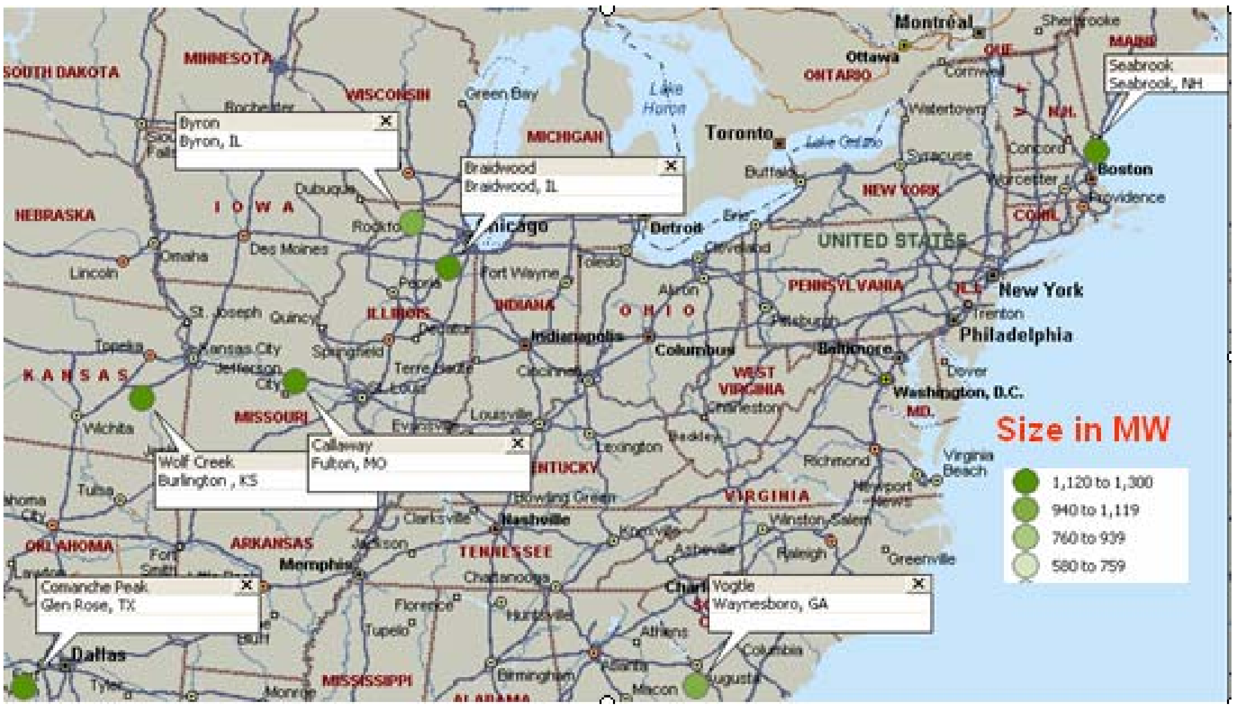
- NERC databases (Electricity& Demand 2003 Database)
- NERC Reliability Assessment Reports
- NERC Regional Study Reports
- NRC reports
- EPRIsolutions databases
- DOE reports and documents from DOE website
- NRC reports and documents from NRC website
- Information from the utilities related to the nuclear power plants
- Study report of the related Regional Transmission Operators (RTS's) or ISO's
- EPRI/EPRIsolutions Probabilistic Reliability Assessment study reports
- DOE 2002 National Transmission Grid Study

With increasing confidentiality in the de-regulated environment, we were unable to obtain detailed information from the utilities. Hence, we had to run full a simulation on the Transfer Capability Evaluation (TRACE) program for summer 2004 for all the Eastern Interconnection to obtain needed transmission loadings around the plants. This was beyond the scope of this study, but was needed to establish line loadings for critical cases.

4 TECHNICAL APPROACH

Decision making for 50 % uprating of the selected PWR plants is a very complex task requiring the assessment of plant interactions with the transmission grid as well as many other factors. Figure 3 shows the location of the candidate plants, as well as their relative size.

Figure 3: Plants under Study



This project deals with the uprating decisions based on the transmission grid only. The study effort focused on the units listed in Table 2 and its results provided general insights regarding these units.

To the following tasks were performed:

1) Identify the number of transmission lines at each voltage level connected to the different plants

2) Identify bottlenecks in the systems around the candidate plants

3) Identify the thermal capacity of the transmission system connected to the different plants, and which ones will be able to “accept” the added capacity, under N-1 conditions.(Static rating of the lines was used to qualify the transmission system).

4) In addition,
    - Identify the transmission lines which are being uprated for different purposes in the vicinity of the plants

5 TRANSMISSION STUDY RESULTS

The study results are described in this section.

5.1.1 Existing and planned transmission enhancements

Many transmission enhancement projects have been reported in the NERC reliability assessment report, NERC regional study reports and utility study reports. None of the reported transmission enhancements are related to the 50% uprating of the nuclear power plants. However, the implementation of these transmission enhancements will significantly benefit the uprating of the selected nuclear power plants. With the exception of one case, the documents reviewed did not show any of the lines emanating from the subject generation stations are subject to any upgrades in the near future, or within the time horizons of the corresponding studies which were reviewed.

The existing and planned enhancements which are directly related to the selected nuclear power plants are described as follow:

- In the ERCOT region, the Morgan Creek-Red Creek-Comanche 345 KV line in west Texas was completed. A total of 1000 miles of new 345 kV line constructions will be completed between 2003 and 2008.

See appendix B for more details on this section.

5.1.2 Existing and Potential Voltage or Stability Problems

Based on our initial survey, only one potential voltage or stability problem directly related to the selected nuclear power plant has been reported or identified in the different reports and data which were reviewed. A more conclusive position on this issue can only be obtained with comprehensive simulation studies and reliability assessments according to the NERC operating standards.

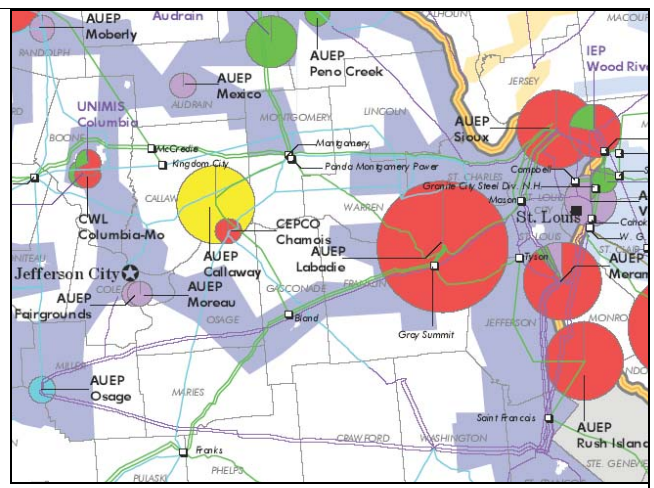
Issues of providing reactive power and regulating transmission voltage under all system conditions are becoming increasingly important. These issues were instrumental in the initiation and spread of the system collapse during the blackout in the Northeastern U. S. and Canada in August 2003. With increasing use of the transmission network by independent generation plants for contract sales, the electric power flow patterns are changing. Although the new flow patterns are not easily predicted, there may be characteristics of the candidate nuclear plants where uprating would either improve or detract from the ability of the transmission network to accommodate the changes stemming from deregulation.

An example of the potential effects of these changes on the operation of nuclear plants is contained in the report of the incident at the Callaway nuclear plant on August 11, 1999. The plant was manually tripped due a rupture of a reheater drain tank line and offsite power was required to supply the plant equipment loads. The Nuclear Regulatory Commission (NRC) report on the incident stated: "During this period, the grid conditions were such that a substantial power flow was occurring from north to south through the local Callaway grid. The licensee stated that the deregulated wholesale market contributed to conditions in which higher grid power flows are likely to occur. The licensee stated that these large flows were observed at this time. This power flow, coupled with a high local demand and the loss of the Callaway generator, resulted in switchyard voltage at the site dropping below the minimum requirements for 12 hours. Although offsite power remained available during the reactor trip transient, the post-trip analysis indicated that in the event that additional onsite loads would have been in operation at the time of the event, 4-16 kV distribution voltage may have decreased below the setpoint of the second-level undervoltage relays separating the loads from offsite power".[2]

An examination of the transmission network in the vicinity of the Callaway plant helps understand characteristics of the network that make the plant more influential in voltage regulation and reactive power supply. This network is shown in Figure 4.

Figure 4: Transmission Network in the Vicinity of the Callaway Nuclear Plant

Transmission System Around Callaway



Other Power Plants Close to Callaway
(and their relative sizes)

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[2] The NRC conducted a special inspection at Callaway from November 29 to December 3, 1999, on the circumstances surrounding the event. The inspectors found that similar conditions existed in 1995 that were undetected by the licensee (Licensee Event Report (LER) 50-483/99-005 (Accession No. 9909200074); NRC Inspection Report 50-483/99-15 (Accession No. ML003684343), dated February 15, 2000).

The figure on the previous pages shows that the plant is approximately half way between the major load centers of Kansas City and St. Louis. It is also near the center of a major North – South transmission path from Iowa into Arkansas. It is probable that this location could greatly influence the ability of the transmission system to transfer power. For an AC transmission system to operate, there must be sufficient reactive power to magnetize the transmission lines, transformers, motors and other elements. The energy represented by this power is exchanged each cycle as the magnetic field alternates and the voltage polarity shifts between positive and negative at each location. This exchange takes place with capacitive elements of the network, shunt capacitors added in strategic locations and generating plants operating in either overexcited or underexcited conditions as needed.

[A general formula that expresses the amount of reactive power needed from a power plant to regulate voltage on a single lossless transmission line is:

$$Q = [\,|V_1|^2 - |V_1|\,|V_r|\cos(\delta)] / X - |V_1|^2 / X_c$$

Where

- Q is the reactive power required from the power plant into the transmission system.
- $|V_1|$ is magnitude of power plant voltage at the connection to the transmission line
- $|V_r|$ is magnitude of receiving end voltage
- X is the reactance between the power plant and receiving end
- δ is the phase angle between power plant and receiving end voltages
- X_c is the capacitive reactance for half of the transmission circuit between the power plant and receiving end.

Careful study of this formula shows a number of attributes of a transmission system. Since the real power transfer on the line and the line reactance establishes the phase angle, it can be seen that for low values of real power flow (small phase angle), the net reactive power is negative and the generator at the power plant will run underexcited to maintain the sending end voltage.] This seems to be more information than necessary. Should it be in an Appendix?

There is a generally accepted principle that reactive power cannot be transmitted for long distances. From this formula, the variable other than phase angle that will determine a direction for reactive power flow is the difference between the magnitudes of power plant and receiving end voltage. If the phase angle responds to real power flow and the power plant voltage is regulated, the receiving end voltage would have to be lower than desired for reactive power to be supplied beyond the end of the line.

When the Callaway plant is not in service, the situation changes. Rather than being a regulated voltage point in the network, the Callaway bus is just a location in the longer transmission paths. Its voltage will be determined by the regulated voltages at the ends of the paths and the power flow through the network. Its auxiliary load may have some effect on this voltage, but it is small enough compared to the rating of 345 kV transmission lines that it is not significant. If the power flow through the network is very low, the Callaway bus voltage will be higher than the regulated voltage at the ends of the network. If network flow is high the Callaway bus voltage will be lower than the regulated voltages.

Perhaps the most important variable in the equation is the system reactance. Reactance is proportional to the distance between the plant and load center and is a key determinant of the relative phase angle. [This relationship is more fully understood by examining the equation for real power transfer through a lossless transmission line. This equation is:

$$P = \frac{|V_1|\,|V_r|\sin(\delta)}{X}$$

] more than necessary? Appendix?

When the Callaway plant is in operation, the distance between regulated voltage points is much less than it is with the plant out of service. This greater distance when the plant is not in service coupled with high power transfer on the lines results relatively high phase angle across the transmission system. At points between the regulated ends of the system, the voltage is lower than at the ends with the minimum voltage at the center of the reactance. For regulated voltage of 1.0 pu at each end and a maximum phase angle of 90 degrees, the minimum voltage is 0.707 pu. In practical systems phase angle differences are much less that 90 degrees, but the mechanism for having lower than acceptable voltage is as illustrated.

These characteristics make the plant very valuable to the transmission system when it is in service. They could also help determine the configuration and size of additional turbine generating and voltage control equipment that might be installed to support the uprate of the reactor. Adding a second turbine generator with the generator rated to supply additional reactive power would provide real power and voltage control at all times that the reactor is in operation. For times when the reactor cannot operate, there may be sufficient value to the system in providing voltage regulation and reactive power that additional equipment could be installed for this purpose.

A significant amount of additional study would be required to precisely quantify the value to the transmission system of reactive power supply and voltage regulation at each of the candidate sites. However, a cursory examination of the transmission network in the vicinity of each plant suggests that the reactive power from Callaway plant would have the highest value followed by Wolf Creek, Seabrook, Byron, Comanche Peak, Vogtle, and Braidwood. This ranking is biased by the thought that multiple unit plants are more likely to have at least one unit in service at all times. In other words, the loss of the reactive power from even larger single units would have the greatest affect on surrounding transmission and may require compensation to prevent transmission problems. [??? correct interpretation?]

6 SCREENING STUDY RESULTS

The following types of data and information were collected and analyzed for the screening study:

- The selected nuclear power generator units (plant, location, owner, region, rating)
- The voltage levels and MVA ratings of transmission lines directly connected to the nuclear power plants
- The loading levels of transmission lines connected to the nuclear power plants in the 2004 Summer power flow case
- Operation problems related to the selected nuclear power plants (from NRC reports)
- Existing and planned transmission enhancement projects
- Existing and planned enhancements or modification of the selected nuclear power plants
- Transmission reliability issues or concerns related to the selected nuclear power plants

The study results, which are shown in the attached spreadsheet file, include the following:

- Basic nuclear power plant information
  - Unit name
  - MW Capacity
  - Total transmission capacity (MVA)
  - Number of transformers / lines and their voltage levels.
  - Branch ratings (MVA)
  - NERC region
  - Location
  - Owner
  - RTO/ISO
  - Control areas
  - Bus numbers and voltage levels in the 2004 Summer power flow case
  - Branch loading in percentage (%) in the 2004 Summer peak loading conditions

- Percentage loading before and after the proposed 50 % uprating
  - Unit name
  - MW Capacity
  - Unit MVA rating (approximate)
  - Total transmission capacity (MVA)
  - Number of transformers / lines and their voltage levels.
  - Transmission loading in the base case before uprating

- Transmission loading in the base case after 50% uprating
- Transmission loading in the single outage case after 50% uprating

The studies were performed with all lines from the corresponding generation station are in service (N-0); one line out (N-1), and two lines out (N-2); where N is the number of lines originating from the corresponding power plant.

The study results are summarized as follow:

In the calculations which follow, the 2004 summer base case for the Eastern Interconnect has been used.

- The existing transmission capacities at the generation stations for most of the selected nuclear power plants (except for Byron nuclear power plant) may be sufficient for supporting the 50 % uprating according to the data available for this study if all of the transformers/lines are in service.

- For the Byron nuclear power plant, it is necessary to upgrade the transformers and transmission lines because the N-1 operating requirements are not met even if all of the related transformers / lines are in service after the 50 % uprating of the power plant. The transmission enhancements should meet the NERC operating standards meet the maintenance requirements of the transformers and transmission lines directly connecting to the nuclear power plants.

- For Byron (1&2), Wolf Creek, and Comanche Peak (1&2), with 50% uprates, and with one line out of service from the corresponding plant, the adjacent lines would be loaded to levels to above 85% of the static ratings. Given the approximate nature of this study, any loading above 85% warrants further study.

- It is necessary to perform comprehensive simulation study and reliability assessment to determine the detailed requirements of the transmission enhancements for the 50 % power plant uprating. More simulation study need to be conducted to identify the limiting contingencies and limiting transmission facilities which may occur after the 50 % uprating of the nuclear power plants.

Table 2: Basic Data for the Nuclear Plants under Consideration

Transmission System Information Around the Nuclear Plants

		Connected Lines Voltage levels, kV									
Unit	**MW NP**	**500**	**345**	**230**	**NERC Region**	**Location**	**Owner**	**ISO/RTO**	**Control Area**	**Bus No.**	**Nominal Voltage (kV)**
Braidwood 1	1125		3		MAIN	Braidwood, IL	Exelon Corp.	Midwest ISO	363 NI	37522	25
Braidwood 2	1125		3		MAIN	Braidwood, IL	Exelon Corp.	Midwest ISO	363 NI	37523	25
Byron 1	1225		2		MAIN	Byron, IL	Exelon Corp.	Midwest ISO	363 NI	37524	25
Byron 2	1225		2		MAIN	Byron, IL	Exelon Corp.	Midwest ISO	363 NI	37525	25
Callaway	1235		3		MAIN	Fulton, MO	Ameren Corp. – Union Electric Co.	Midwest ISO	356 AMRN	30225	25
Wolf Creek	1236		3		SPP	Burlington, KS	Westar Energy, Great Plains Energy, Kansas Electric Power Cooperative	Midwest ISO	541 KACP	56751	
Seabrook	1242		3		NPCC	Seabrook, NH	TFPL Energy Seabrook LLC	ISO New England	28 JCP&L	72869	25
Vogtle 1	1215		5		SERC	Waynesboro, GA	Georgia Power, Oglethorpe Power Corp., Municipal Electric Authority of Georgia, City of Dalton	Southern Company	146	15250	25

Table 2: Basic Data for the Nuclear Plants under Consideration

Transmission System Information Around the Nuclear Plants

		Connected Lines Voltage levels, kV									
Unit	**MW NP**	**500**	**345**	**230**	**NERC Region**	**Location**	**Owner**	**ISO/RTO**	**Control Area**	**Bus No.**	**Nominal Voltage (kV)**
Vogtle 2	1215	2			SERC	Waynesboro, GA	Georgia Power, Oglethorpe Power Corp., Municipal Electric Authority of Georgia, City of Dalton	Southern Company	146	15251	25
Comanche Peak 1	1160		3		ECORT	Glen Rose, TX	TXU Energy	ERCOT			
Comanche Peak 2	1160		2		ECORT	Glen Rose, TX	TXU Energy	ERCOT			

Table 3: Line Flows for Baseline Plant Capacity (All Line in Service, N-0)

Baseline Plant Capacity																
			Connected Lines Voltage levels, kV			Branch Flows, MVA						% of Static Rating			
Unit	MW	Total Trans Capacity (MVA)	500	345	230	Branch1 Flow Rating (MVA)	Branch2 Flow Rating (MVA)	Branch3 Flow Rating (MVA)	Branch4 Flow Rating (MVA)	Branch5 Flow Rating (MVA)	Voltage (pu)	Branch1 Actual Flow % of Rating	Branch2 Actual Flow % of Rating	Branch3 Actual Flow % of Rating	Branch4 Actual Flow % of Rating
Braidwood 1	1201	4385		3		1355	1355	1675			1.0184	57	59	18	
Braidwood 2	1179	4385		3		1355	1355	1675			1.0267	52	58	17	
Byron 1	1195	2590		2		1234	1356				0.9868	60	6?????		
Byron 2	1175	2590		2		1234	1356				0.9865	66	57		
Callaway	1194	4220		3		1420	1400	1400				20	31	31	
Wolf Creek	1185	3211		3		960	1156	1095				51	41	23	
Seabrook	1161	5305		3		1795	1795	1715			1.0073	49	19	4	
Vogtle 1	1148	4033		5		1095	565	830	830	713	0.9898	37	48	47	47
Vogtle 2	1149	5372	2			2672	2700				1.0209	35	12		
Comanche Pk 1	1150	3659		3		1631	1072	956			1.002	40	23	42	
Comanche Pk 2	1150	3065		2		1631	1434				1.0021	34	46		

*Note MW shown is the MW loading of the power flow cases run.

Table 4: Line Flows for Baseline Plant Capacity (N-0, and N-1)

Unit	MW	MVA	Transmission Capacity (MVA)	Transmission Capacity (MVA) Worst N-1	500 kV	345 kV	230 kV	N-0	N-1
Braidwood 1	1201	1273	4385	2710		3		29%	47%
Braidwood 2	1179	1308	4385	2710		3		30%	48%
Byron 1	1195	1219	2590	1234		2		47%	99%
Byron 2	1175	1200	2590	1234		2		46%	97%
Callaway	1194	1196	4220	2800		3		28%	43%
Wolf Creek	1185	1226	3211	2055		3		38%	60%
Seabrook	1161	1192	5305	3510		3		22%	34%
Vogtle 1	1148	1149	4033	2938		5		28%	39%
Vogtle 2	1149	1169	5372	2672	2			22%	44%
Comanche Peak 1	1150	1173	3659	2028		3		32%	58%
Comanche Peak 2	1150	1173	3065	1434		2		38%	82%

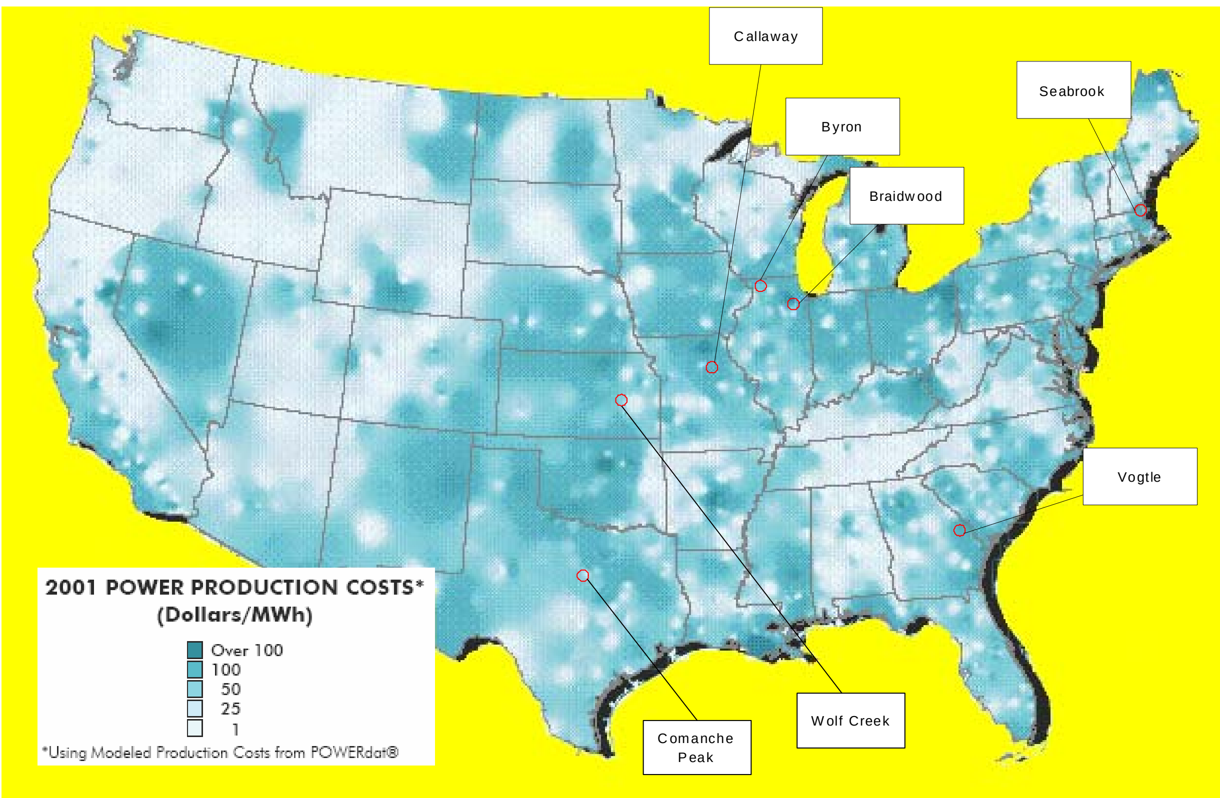
Table 5: Line Flows for With 50% Plant Uprate (N-0, and N-1)

Plant			Transmission Lines						
Unit	MW	MVA	Transmission Capacity (MVA)	Transmission Capacity (MVA) Worst N-1	500 kV	345 kV	230 kV	N-0	N-1
Braidwood 1	1802	1910	4385	2710		3		44%	70%
Braidwood 2	1769	1962	4385	2710		3		45%	72%
Byron 1	1793	1829	2590	1234		2		71%	148%
Byron 2	1763	1799	2590	1234		2		69%	146%
Callaway	1791	1794	4220	2800		3		43%	64%
Wolf Creek	1778	1838	3211	2055		3		57%	89%
Seabrook	1742	1788	5305	3510		3		34%	51%
Vogtle 1	1722	1723	4033	2938		5		43%	59%
Vogtle 2	1724	1753	5372	2672	2			33%	66%
Comanche Peak 1	1725	1760	3659	2028		3		48%	87%
Comanche Peak 2	1725	1760	3065	1434		2		57%	123%

7 PRODUCTION COSTS IN THE REGION

One factor that may influence the uprating of the plants may be attributed to the power production costs in the region where the plants are operating, since power for these plants would be competing in such areas. Data on production costs is not constant, and accurate data is very difficult to obtain, given the competitive nature of the utility business today. Yet, for comparison purposes, Figure 5 is based on 2001 production as was reported by POWERdat. Examining this figure, and assuming all technical constraints being equal (i.e., reliability, thermal constraints, voltage constraints, etc.) it can be deduced that uprating of plants in the areas of the highest production costs can be supported easier than those in less costly areas. Based on this logic, Table 6 is constructed using the approximate production costs as a basis. In this figure an “economic merit index” of uprating of the 11 plants is presented. Since the data is limited, the this index is assumed to be either 1 or 2, with 1 being the most favorable, i.e., the plant is located in higher production cost area. Had there been more plants to contrast, or more granular production cost data, the scale would have been expanded to 5. Plants in Tennessee would probably score closer to 5, using the above logic.

Figure 5: Approximate Area Production Costs ($/MWh)



Uprating based on economic factors may well dictate the process; hence, it is recommended that this area be further investigated.

Table 6: Uprating Advantage Based on Approximate Area Production Costs
1= Favorable Cost Differential; 2 = Less Favorable

Unit	Location	Economic Merit Index Based on Approximate Area Production Costs ($/MWh)
Braidwood	Braidwood, IL	1
Byron	Byron, IL	1
Callaway	Fulton, MO	2
Wolf Creek	Burlington, KS	2
Comanche Peak	Glen Rose, TX	2
Seabrook	Seabrook, NH	1
Vogtle	Waynesboro, GA	2 (should this row be shaded?)

8 OPERATION UNDER MINIMUM LOAD CONDITIONS

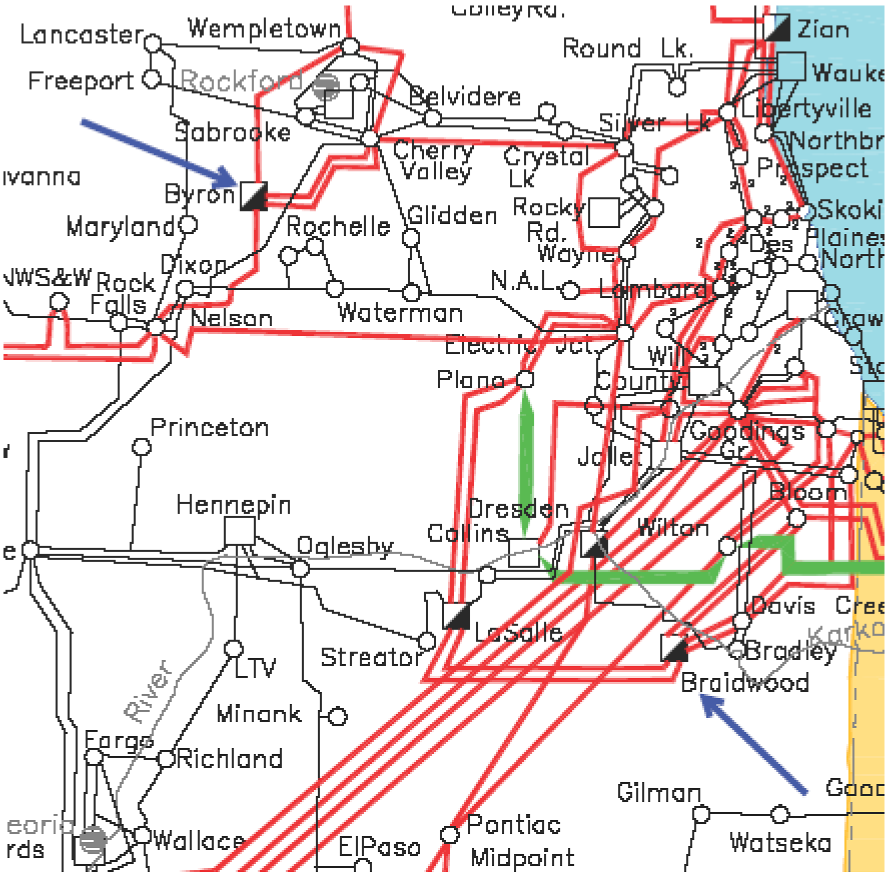
A consideration in determining which nuclear plant may be most suitable for a 50% uprate is the percentage of time the transmission network can reliably accept full power from the plant. In systems where the load profile has extreme peaks and valleys, the more difficult times to maintain acceptable voltage profiles and spinning reserve margins are often the low load periods. At these times, operation of a few plants with the lowest fuel costs may be most efficient, but the location of these plants may not provide the needed voltage regulation. If one of these plants were to trip off line or a critical transmission line were to trip, there may not be sufficient reserve capacity in the remaining operating plants to prevent a cascading blackout of the system. These were the events that led to the blackout in Italy on September 28, 2003. To assure reliable system operation, the system operators must limit the generation from some plants and keep less efficient plants in critical locations running to regulate system voltage.

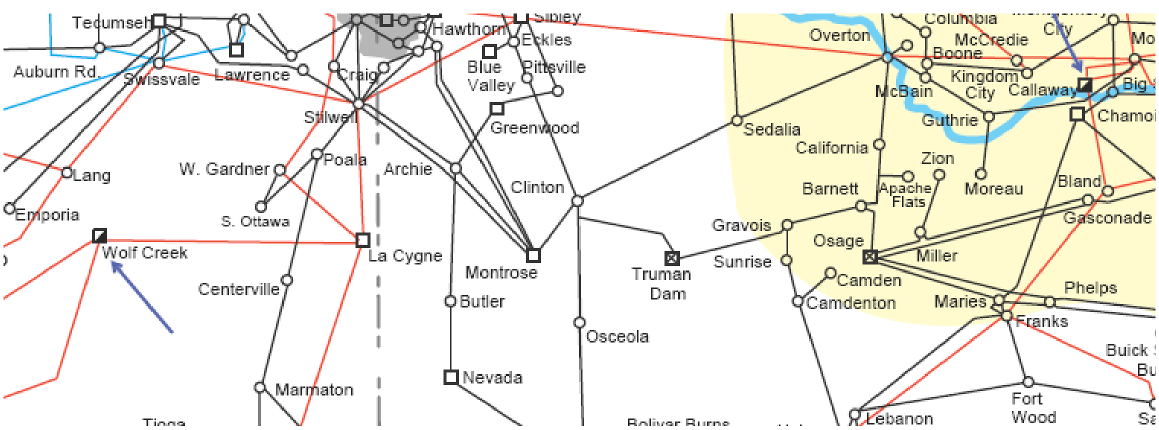
The scope and information available for this study did not include detailed analysis of system voltages and power flows at minimum load. Rather, a more heuristic assessment based on location of the candidate nuclear plants indicates which would be most impacted by low system load conditions. This assessment considered the relative size of the uprated plant compared to other generation sources in the area. If a plant is large compared to other plants, it is likely that its output will have to be reduced under light load conditions to have sufficient spinning reserve to protect from the loss of this source.

The assessment also considered the distance from the nuclear plant to major load centers and the number of transmission circuits from the plant. These factors influence the ability of the nuclear plant to help regulate the system voltage and the likelihood that transmission line outages would isolate the plant from the load center. The transmission system operator should consider all of these factors in scheduling power from the nuclear plant and in deciding which other generation plants must be kept in operation for system security. A ranking of the candidate plants based on the likelihood that the transmission network in the vicinity of the plant could accept all the power available from the plant at any time it could be generated would likely provide the highest value for the Seabrook plant followed by Braidwood, Comanche Peak, Byron Vogtle, Callaway and Wolf Creek. In other words, Seabrook is less likely to have to run at reduced power during light load periods and Vogtle, Callaway and Wolf Creek are more likely to have to reduce power during light load periods.

A more difficult assessment is the question is whether the nuclear plant would be the lowest cost power source during low system load conditions. The characteristics of nuclear generation do not allow the plants to change output on an hourly basis as may be required under a fully competitive bidding process. Therefore, there are other arrangements to determine how much the plant is to be paid for its production. It is outside the scope of this study to define these arrangements for each plant and consider their impact during low system load conditions.

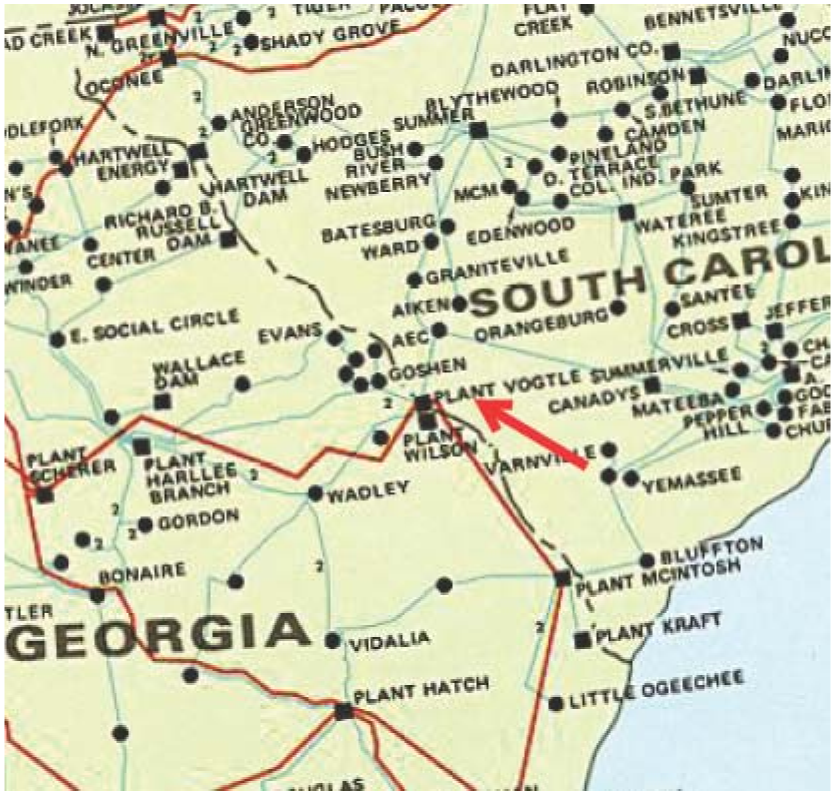
APPENDIX A: SYSTEM MAPS





AC–DC–AC Link
OKLAUNION
SUNNYSIDE
BOWMAN
PARIS
VALLEY
GRAHAM
W. DENTON
NW. CARROLLTOWN
SULPHUR SPGS
EAGLE MTN
NORTH LAKE
ROYSE
PARKER
EVERMAN
BENBROOK
FORNEY
CEDAR HILL
TRICORNER
DECORDOVA
MULBERRY CREEK
COMANCHE PEAK
VENUS
TRINIDAD
WHITNEY
BIG BROWN
COMANCHE
ELM MOTT
TRADINGHOUSE CREEK
TEXAS
LAKE CREEK
LIMESTONE
JEWETT
TWIN OAK
NUCOR
TEMPLE
TNP ONE
KILEEN
GIBBONS CREEK

WYMAN
N. H.
VT.
S. GORHAM
BUXTON
COOLIDGE
± 450 kv
DEERFIELD
NEWINGTON
TIMBERSWAMP
DUNBARTON
MERRIMACK
SEABROOK
SCOBIE
TEWKSBURY
GOLDEN HILLS
VERMONT YANKEE
NORTHFIELD MTN
WOBURN
N. CAMBRIDGE
SANDY POND
MYSTIC
WALTHAM
KINGSTON
WALPOLE
PRATTS JCT.
HOLBROOK
AUBURN ST.
BERKSHIRE
CARVER
PILGRIM
MASS.
MILLBURY
MEDWAY
CANAL
STONY BROOK
BRIDGEWATER
LUDLOW
CARPENTER HILL
OCEAN S.P.
BRAYTON POINT
BLOOMFIELD
MANCHESTER
KENT
CONN
CARD
MIDDLETOWN
R.I.
LONG MTN.
COKYAK
MONTVILLE
MILLSTONE
SCOVILL ROCK
SOUTHINGTON
EAST SHORE
SEE NEW YORK


N. GREENVILLE
SHADY GROVE
OCONEE
ANDERSON
GREENWOOD CO.
HODGES
BUSH RIVER
SUMMER
BLYTHEWOOD
DARLINGTON CO.
ROBINSON
BENNETSVILLE
S. BETHUNE
CAMDEN
PINELAND
O. TERRACE
COL. IND. PARK
SUMTER
WATEREE
KINGSTREE
HARTWELL ENERGY
HARTWELL DAM
NEWBERRY
MCM
RICHARD B. RUSSELL DAM
CENTER
BATESBURG
WARD
EDENWOOD
GRANITEVILLE
AIKEN
SOUTH CAROL
ORANGEBURG
SANTEE
CROSS
E. SOCIAL CIRCLE
EVANS
AEC
WALLACE DAM
GOSHEN
PLANT VOGTLE
SUMMERVILLE
CANADYS
MATEEBA
PEPPER HILL
PLANT WILSON
VARNVILLE
YEMASSEE
PLANT SCHERER
PLANT HARLLEE BRANCH
WADLEY
GORDON
BONAIRE
BLUFFTON
PLANT MCINTOSH
GEORGIA
VIDALIA
PLANT KRAFT
PLANT HATCH
LITTLE OGEECHEE

APPENDIX B: PLANNED TRANSMISSION ENHANCEMENTS IN EASTERN INTERCONNECTION

Many transmission enhancement projects have been reported in the NERC reliability assessment report, NERC regional study reports and utility study reports. Although most of the reported transmission enhancements may not directly consider the 50% uprating of the nuclear power plants, the implementation of these transmission enhancements will significantly benefit the uprating of the selected nuclear power plants. With the exception of one case, the documents reviewed so far show that none of the lines directly connecting to the subject ten generation stations are subject to any upgrades in the near future, or within the time horizons of the corresponding studies which were reviewed.

The existing and planned transmission enhancements for each region are described as follow:

- ERCOT
  The major transmission constraints in ERCOT continue to be the transfer of energy into the areas of Dallas-Fort Worth and Houston load centers. The solutions to the transmission constraints include new construction of transmission facilities, special protection systems, if necessary, that activated when the specified contingencies occur until new facilities can be constructed. In operation, the congestion management through RMR (reliability must run) services and market protocols (including demand participation) may prove cost effective.

  A number of 345 kV and 138 kV transmission lines have been completed or under construction in west and south Texas that will relieve the existing constraints. A total of 1000 miles of new 345 kV line constructions will be completed between 2003 and 2008.

- ECAR
  Current plans call for the addition of about 123 miles extra high voltage (EHV) transmission lines (> 230 kV) that are expected to enhance and strengthen the bulk transmission network. A new AEP's 765 kV line is expected to be in service by June 2006. Significant amount of new generation have been proposed in ECAR over the next ten years. The full output of the generation will not be attainable without exceeding transmission limit depending on specific output patterns of the existing and new generation.

- MAIN
  For the ten-year planning horizon (2003-2012), MAIN expects its transmission system to perform adequately if planned reinforcements or some equivalent of these plans are completed on schedule.

- NPCC
  The existing interconnected bulk electric transmission systems in NPCC region will meet the NPCC planning criteria. From 2003 to 2010, the transmission enhancements include 25 circuit-miles at the 230 kV voltage level, 60 circuit-miles at 345 kV voltage level, and 362 circuit-miles HVDC link.
- SERC
  The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demands and energy requirements and firm transmission reservations under normal and contingency conditions. The planned transmission additions include 1766 miles of 230 kV, and 526 miles of 500 kV transmission lines

The planned transmission enhancements in the next 10 years are shown in the following table.

Table B.1 : Planned Transmission Circuit Miles (230 kV and above)

Region	2002 Existing	2003 – 2007 Additions	2008 – 2012 Additions	2012 Total Installed
ECAR	16422	122		16544
FRCC	6769	293	108	7270
MAAC	7031	70		7101
MAIN	6178	438	75	6691
MAPP-U.S.	14356	114		144470
MAPP-Canada	6656	57	242	6955
NPCC-U.S.	6351	589	37	6977
NPCC-Canada	28780	235	87	29102
SERC	28880	1326	966	31179
SPP	7639	637	245	8521
Eastern Interconnection	**129062**	**3981**		**1760**
ERCOT	**7301**	**1049**		**8350**
WECC-U.S.	57678	7089	3258	61856
WECC-Canada	10751	316	422	10868
WECC-Mexico	563	24		587
Western Interconnection	**68992**	**7429**	**3680**	**73311**
NERC	**205355**	**7429**	**3680**	**216464**

The existing and planned transmission enhancements which are directly related to the selected nuclear power plants are described as follow:

- In the ERCOT region, the Morgan Creek-Red Creek-Comanche 345 KV line in west Texas was completed.

Click here to view the planned transmission lines in the regions where the plants under consideration are located. The data shown is extracted from the latest data available from NERC ES&D 2003 Data base.

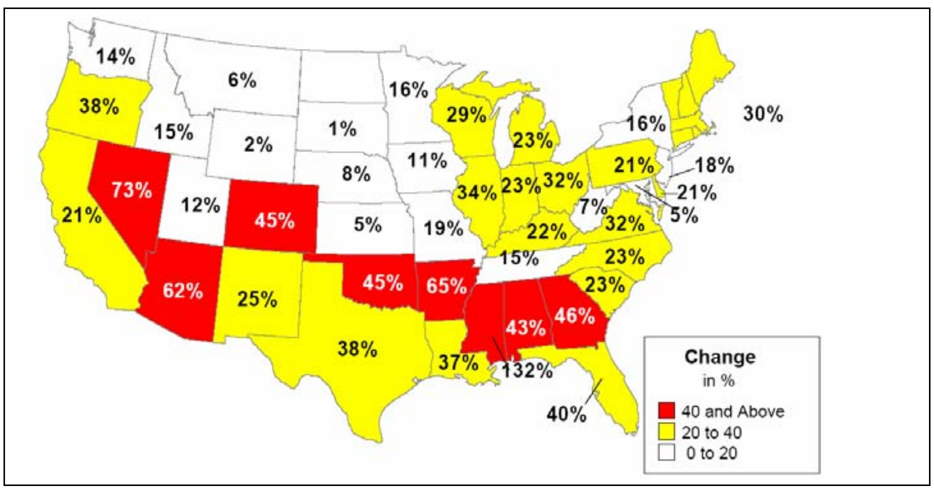
APPENDIX C: RESOURCE ADEQUACY ASSESSMENT

Based on the 2003 NERC long-term reliability assessment report, "resource adequacy will be satisfied in the near term (2003-2007) throughout North America, provided new generating facilities are constructed as anticipated." Electricity demand is expected to grow by about 67000 MW in the near term. The total of the projected generation resource additions over this same period will be about 89,000 MW depending upon the number of merchant power plants assumed to be in service. Although the total generation resources appear adequate, the generation additions and the resulting capacity margins are not evenly distributed across North America.

Projected new generation additions

The new generation additions are shown in the following figure.

Figure C.1: Percentage of projected new generation additions 1998-2007 as a percentage of 1998 total installed generation



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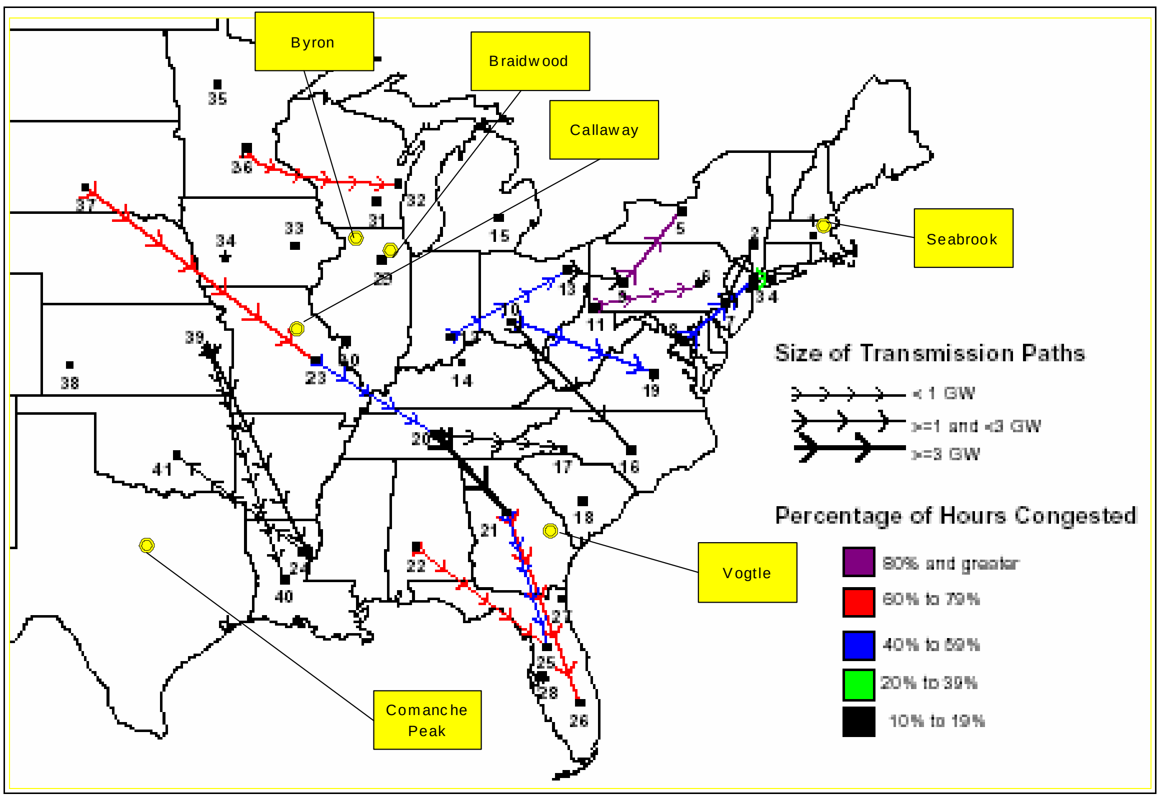
APPENDIX D: CONGESTION IN THE EASTERN INTERCONNECT

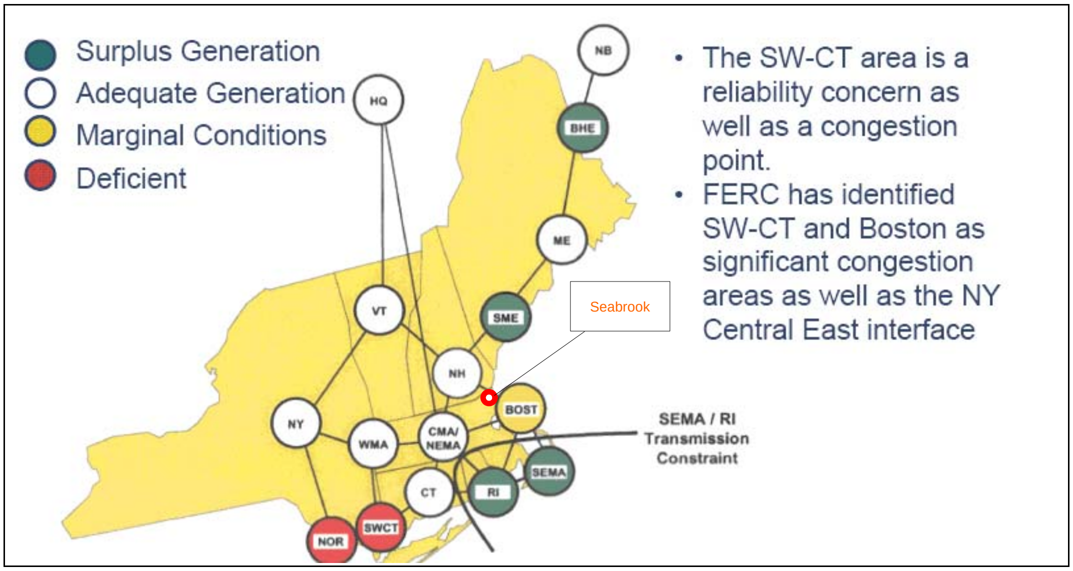
The following figures represent known congestion areas in the Eastern Interconnection with respect to the subject plants as was identified by DOE in the 2002 National Transmission Grid Study. Although these figures show the subject plants to be outside the major congestion paths identified by DOE, it can not be determined, without more detailed studies, what the effect of the uprating can have on these congestions paths.

Figure D.1: Congestion in the Eastern Interconnect



Source: 2002 **the National Transmission Grid Study**

Figure D.2: Congestion areas in the North East



APPENDIX E: ACRONYMS

ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
IE	Eastern Interconnection
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
N-1	In a contingency analysis, engineers present a model of the electrical system with hypothetical demand conditions and a base case of operating generators and lines. Large generators and major lines are then taken off line one at a time to mimic unplanned outages. This is called an N-1 contingency analysis: all but 1 of the n pieces of major equipment in the electrical system is assumed to operate normally.
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
TRACE	Transfer Capability Evaluation Program
WECC	Western Electricity Coordinating Council

Add NERC
DOE
EPRIsolutions
NRC
RTO
ISO

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