Achieving Higher Capacity Factors in Nuclear Power Plants Through Longer Operating Cycles

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Abstract

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Research into designing nuclear power plants for higher capacity factors through longer operating cycles was initiated. Over 40 representatives from industry were interviewed to solicit their insights into the capabilities and limitations of current nuclear power plant designs. The results of these interviews serve as a basis from which to proceed in a formal effort to redesign power plants for longer operating cycles and higher capacity factors.

Strategies for redesigning power plant systems were developed. These included designing plants to allow monitoring, inspection, calibration, maintenance and repair (MICMR) closer to full power than previously possible (at higher modes of operation); decreasing the time required to perform MICMR, and increasing the times between required MICMR. The results of the interviews regarding the steam generators were then used in conjunction with the strategies to illustrate how innovative design solutions can be synthesized from the strategies.

Probabilistic methods for predicting performance of complex systems were reviewed. Monte carlo simulation was chosen as the prefered tool for future research because of its flexibilities in handling complex, time dependent problems with interdependencies, and external perturbations. The basis of any redesign of power plant systems should be economics. Therefore, deterministic and statistical cost benefit analysis methods were reviewed.

A simplified simulation model of a pressurized water reactor was constructed, with the feedwater system modelled in greater detail. The model's logic was simplified slightly to facilitate comparison with an analytical solution to validate the model's structure. Perturbation calculations were performed on the original model to determine the value of adding redundancy, increasing reliability, and decreasing repair time. It was concluded that adding redundancy in the feedwater heat exchangers, increased mean time to failure of feedwater components, and decreased mean time to repair of feedwater components improved capacity factor significantly. This analysis was intended to show how simulation techniques can be used to evaluate modifications before costly implementation.

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Chapter 1 - Background, motivation and problem statement

Utilities have long recognized that enhanced economic performance through achievement of improved capacity factor provides an incentive to minimize the duration of refueling outages. However, because perceived needs for plant shutdown to perform maintenance and repairs dovetailed with economic optimums for core cycle life, little incentive has existed to run LWRs to cycle lengths longer than 12 to 18 months. Recently however, some US utilities have extended their operating cycles to 24 months. Nevertheless, this is not a widely accepted strategy nor is it obvious that this length is ambitious enough.

The goal of this project is to examine the strategy of improving capacity factor by increasing cycle length beyond 24 months. Such an examination entails two facets. First, the identification of engineering activities necessary to insure reliable operation throughout the duration of the extended operating cycle. Second, the design and economic assessment of cores which can achieve lifetimes consistent with extended cycle length. This project addresses only the first facet. A parallel activity is underway to address the second facet.

This project is applicable to both operating and advanced reactor designs. In light of the large amount of activity already expended on core and safety system design of advanced systems, it is likely that the next round of advances in reactor safety and economic performance will be achieved by engineering focus on achieving improved operational reliability. In this regard, examination of gains to be achieved through enhanced monitoring, inspection, calibration, maintenance and repair (MICMR) activities is strongly warranted. This project is focused on the development of strategies to improve capacity factor by achieving reliable, longer operating cycles by enhanced MICMR activities.

This project is also intended to support the work of Hejzlar, Tang, and Mattingly. [Refs. 1, 2 and 3]

The rest of this chapter is intended to provide a background of the current economic environment in the electric utility industry, and the economic driving factors for nuclear power in particular.

1.1 Competition

1.1.1 Domestic environment

Historically, US utilities operated as a cost-plus industry. A cost plus environment meant that the investors were assured of a "fair rate of return." All costs incurred by the utility in operations were covered in the rate base. The investors , however, received an additional return on their capital investments, which was also covered in the rate base. If electrical production costs increased, the utilities appealed to the Public Utility Commission (PUC) for a rate increase. Under this system, there was little incentive for producing power cheaply, as long as utilities could justify costs to the PUC. [Ref. 4]

With the passage of the 1992 Energy Policy Act, the United Sates electric utility industry started down the road to competition. Thus, only recently has widespread competition emerged. Under the new system, utilities are beginning to be required to purchase independent power producers' (IPPs) electricity if it is cheaper than can be produced through the utility. This allows small, non-utility producers to construct cheap, natural gas combined cycle power plants, and undercut the utilities. Fortunately for the utilities, the capacity of the IPPs is still relatively small. Unfortunately, it is growing. Therefore, there is now significant impetus in the United States to make utility produced power cost competitive.

This is especially true for nuclear power plants. Many of these plants have enormous capital debt, which increases the overall costs associated with nuclear generation. Compounding that is the historically poor operating performance achieved by these plants and the high operating and maintenance costs. These components of cost will be discussed later, but nuclear generating costs are, in general, slightly higher than coal and significantly higher than natural gas powered electrical generation. The advantage of nuclear power is its relatively cheap fuel.

1.1.2 International environment

Internationally, nuclear utilities are facing the same pressures. Where available, natural gas fired power plants can produce electricity cheaply and efficiently. Where natural gas is not plentiful, coal, oil and hydro powered generators are becoming more competitive with nuclear generation. Compounding the economics is the issue of waste disposal. The United Kingdom has deregulated its utility industry and Japan is proceeding towards deregulation. Although regulatory structures differ from country to country, in the long run, cheaper, simpler electric production sources have the potential to overtake the market. Therefore, the problem of nuclear power economics is a global issue, not just a localized political issue.

1.1.3 Summary

Electric power production is becoming a competitive industry. Worldwide, nuclear utilities will soon face pressures to become cost competitive. There are several ways to reduce production costs - each of which will be discussed subsequently. However, if large generating stations fail to become competitive, they may eventually be forced out of business.

1.2 The economics of nuclear electricity generation [Ref. 5]

This section is intended to provide an overview of the elements of cost associated with nuclear power electricity generation. This section will make explicit in a somewhat simplified fashion the factors that affect nuclear power costs, and will suggest strategies for improving nuclear power economics.

For any business, net profits are related to revenues and expenses by the following equation:

$$NP\,[\$] = R - E \tag{1.1}$$

Where NP [$] = Net Profits
R [$] = Revenues
E [$] = Expenses

To understand the importance of this simple equation, consider how it affects the overall costs to consumers. In a competitive industry, the maximum price that utility generated electricity can be sold at is set by the price (P) of competitor's power expressed in [$/MWh-e]. If the plant cannot sell power at least as cheaply as its competitor, it cannot sell power. The revenues generated over a given time period are:

$$R\,[\$] = P * C * T_{gen} \tag{1.2}$$

Where P [$/MWe-h] = Price
C [MWe] = Nominal electric generating capacity
T_{gen}[h] = Generating Time

For a given amount of power produced over a given production time, revenues are fixed. If expenses are greater than revenues, then the plant loses money. This does not mean that it should be shut down, but it certainly means that the expected return to investors is insufficient. Let us look more deeply into the components of revenues and costs.

1.2.1 Revenues

As mentioned before, revenues are a function of the rate of power production multiplied by the time this rate of production is maintained multiplied by the mean price received for the power sold. To further decompose it:

$$R = P * C * (\eta / \eta_o) * CF * T \tag{1.3}$$

where CF = Mean capacity factor
(η/η_o) = Thermal efficiency / nominal thermal efficiency
T [h] = Total period of time under consideration

What is seen is that there are a number of ways to increase revenues. The first is to increase the electric power capacity rating of the plant, C. This usually requires modifications such as revisiting technical specifications, re-doing safety calculations with better analysis tools, and when necessary, modifying plant safety systems to accommodate the power uprating. Therefore, the first assumption made is that this option has been fully exploited.

The second way to increase revenues is to increase the ratio of the average plant thermal efficiency over the period in question to the nominal thermal efficiency over all time (η/η_o). The reason it fluctuates is that the temperature of the ultimate heat sink varies from day to day and from season to season. So $\eta = \eta(t)$, and is out of control of the operator. It is further assumed that the nominal thermal efficiency has been fully maximized.

The third way to increase revenues is to increase average capacity factor. The capacity factor is defined as:

$$CF = \frac{\text{Actual energy produced over a period of time}}{\text{Maximum energy that could be produced over that period.}} \qquad (1.4)$$

So if a plant ran for 200 effective full power days in the period of 1 year, CF = 200 / 365 = 0.55, or 55%. If the plant were available for 300 EFPDs, the capacity factor would be 82%, and revenues would increase by 50%. Increasing capacity factor will be one of the main focuses of this thesis.

Finally, for practical purposes, T is merely an accounting tool that sets the period of time over which revenues are to be computed. However, in the long run, T can be used to represent the design life of the plant. As such, life extension will affect T_{max} - the maximum operating life of the plant. However, that is beyond the scope of this project.

1.2.2 Expenses

Like revenues, expenses can be further decomposed. Let us look at the various cost components associated with nuclear power, which for present purposes may be disaggregated as follows:

$$E\,[\$] = (O\&M) + S + F + CP + RC + FF + SR \qquad (1.5)$$

Where O&M [$] = Operations and maintenance costs
S [$] = Salaries
F [$] = Fuel costs
CP [$] = Capital costs
RC [$] = Electrical replacement energy costs
FF [$] = Future expense funds
SR [$] = Safety regulation costs

Now, let's look at each component individually.

1.2.2.1 Operations and maintenance costs

Operations and maintenance costs (O&M) are those costs associated with maintaining the plant material condition and providing operations services.

$$\text{O\&M costs} = (M + O) \tag{1.6}$$

Where M [$] = material condition costs
O [$] = operations services costs

1.2.2.2 Salaries

Salaries (S) are associated with the payment of the workforce necessary to produce and distribute power to the consumer. They are not explicitly included in O&M costs here, because they are such a dominant cost that they deserve to be considered separately. (In general, however, discussions of operations and maintenance costs typically include personnel expenses.) The total salary paid is the product of the mean workforce size (which can vary in time due to significant augmentation during refueling outages), the average wage (including overhead and benefits), and the time period in consideration.

$$S = (\underline{WF}) * H * T \tag{1.7}$$

Where $(\underline{WF})$ [person] = Mean workforce
H [$/person-h] = Hourly wage

1.2.2.3 Fuel costs

Fuel costs (F) are those costs associated with maintaining the heat source to produce electricity. In standard light water reactors, the fuel costs are a function of unit energy costs (F_c), electrical power capacity (C), thermal efficiency (E), capacity factor (CF) and cycle time (T). In an online refueling scheme, the unit energy costs are constant because enrichment does not need to increase for longer cycles. This is a significant advantage over batch refueling schemes, because in going to longer operating periods in batch schemes, the enrichment and reactivity control costs can increase significantly.

$$F = F_c * (C/E) * CF * T \tag{1.8}$$

Where F_c [$/MWth h] = unit energy costs

1.2.2.4 Capital costs

Capital costs (CP) are associated with paying back the investors for their initial capital outlay with a fair rate of return included. It is a function of the plant value (V) and the fraction of the power plant value which is charged as an expense (L) during the time interval, (T). Here we assume all such costs are levelized over the life of the plant (i.e. charged at an equivalent constant rate).

$$CP = (V) * L * T \tag{1.9}$$

Where V [$] = Plant value
L [$/$h] = Rate of capitalization

1.2.2.5 Replacement power costs

Replacement electrical energy is the cost (RC) of buying more expensive electricity from external sources to replace the power deficit experienced when one of the utility's operating plants is off-line or at reduced power. It is a function of the average power deficit, the unit replacement power cost, and the time.

$$RC = (\underline{DP}) * C_r * T \tag{1.10}$$

Where $\underline{DP}$ [MWe] = average power deficit
= power rating * capacity loss
C_r [$/MWe] = unit replacement power cost

1.2.2.6 Future expense funds

Future expenses funds (FF) are associated with the costs of plant decommissioning and spent fuel and waste disposal, and time.

$$FF = (D + W) * T \tag{1.11}$$

Where D [$/h] = rate of savings for decommissioning
W [$/h] = rate of savings for waste disposal

1.2.2.7 Safety regulation costs

Safety regulation is the cost (SR) associated with normal licensing fees and with punitive actions by the safety regulatory authority. This is a difficult quantity to define or quantify. Nevertheless, it is real and should be included in any discussion of nuclear related costs. It is a function of fines and backfit hardware.

$$SR = [P_r + B] * T \tag{1.12}$$

Where P_r [$/h] = Average cost of regulatory fees and fines per unit time
B [$/h] = Cost of backfit hardware per unit time

This concludes the summary of the factors associated with plant expenditures:

$$\text{Expenses [\$]} = \{ (M+S) + C^*F_c(\underline{CF/\eta}) + \underline{WF}^*H + V^*L + \underline{DP}^*C_r + (D+W) + [P_r + B]\} * T \tag{1.13}$$

1.2.3 Net profits, revisited

Combining the results of the previous discussions yields a formula that summarizes the factors comprising nuclear power economics.

$$\text{Net Profits [\$]} = [\{C * CF * (\eta/\eta_o) * P\} - \{ (M+S) + C^*F_c(\underline{CF/\eta}) + \underline{WF}^*H + V^*L + \underline{DP}^*C_r + (D+W) + [P_r + B]\}] * T \tag{1.14}$$

This research is intended to increase net profits by improving capacity factor. Clearly, capacity factor affects many aspects in the above equation, the most important of which is revenues. The more subtle effects on net profits are increased fuel costs, decreased replacement power costs, and decreased regulatory costs.

For a continuous refueling scheme, the fuel costs are only a linear function of capacity factor (Revenues ÷ Fuel Costs = Constant). In this scheme, going to a longer cycle or a higher capacity factor does not increase the ratio of revenues to fuel costs. Therefore, the factors that we will consider in this thesis are (1) increased revenues, (2) decreased replacement power costs, and to a lesser extent (3) decreased regulatory-associated availability losses.

For a batch refueling cycle, capacity factor does not greatly affect fuel cycle costs. In reality, current US LWR owners typically plan to run at a high capacity factor between refuelings. If they run very well, they use up all the excess reactivity in the core. If they do not run well, then they may be forced to "throw out" part of the excess reactivity (i.e. off-load a batch fraction of the core that is not fully utilized). So for a batch cycle, the fuel costs for *a given cycle length* are not dramatically affected by an improved capacity factor. However, increasing the cycle length can significantly increase the unit fuel costs, by increasing uranium ore and enrichment requirements.

1.3 The state of current plants

US PWRs and BWRs had a three year median capacity factor of about 72% for the 1991-1993 period. [Ref.6] In Canada - where refueling outages are not a limitation because of the online refueling capabilities of the CANDU reactors - the three year average capacity factor is around 69%.[Ref. 7] These levels of performance are typical for most operating reactors around the world - with a few notable exceptions that are discussed later. There are two reasons for this mediocre record. First, when these plants run, they often run poorly. Maintenance or safety problems force plants to reduce power or shut down frequently. Second, LWRs have to shut down periodically for refueling or major surveillances, calibrations, maintenance, and repairs. The duration of these outages vary significantly betwen BWRs and PWRs of various standard designs and between plants of the same standard design operated by different utilities. In the US, they are on the order of 65 days every 18 to 24 months, but range from about 30 days to over 100 days depending on the specific plant.

The two areas of capacity loss suggest three ways to increase capacity. First, decrease major outage durations. Second, increase the period between major outages. Third, improve operational period availability (i.e. reduce forced outages). Figure 1.1 illustrates how shorter outages and less frequent outages affect capacity factors, given perfect reliability during normal operations (i.e. no forced outages).

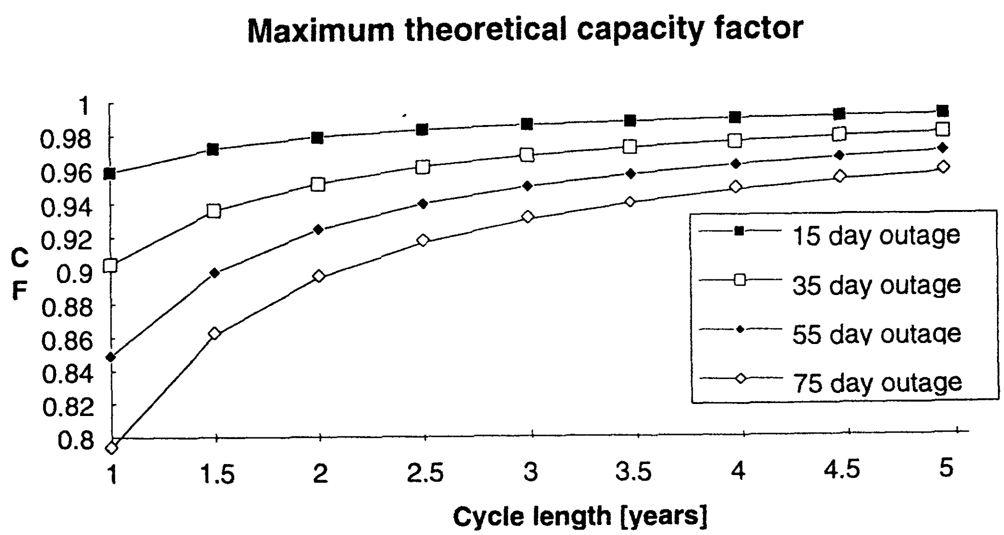

Figure 1.1

Two facts emerge from Figure 1.1. First, if outages can be completed very quickly (say 15 days), there is very little gain from increasing cycle length beyond 12 to 18 months. Second, if outages cannot be performed very quickly, then significant improvement in capacity factor can be achieved by extending the cycle length.

1.3.1 Short outage / short cycle strategy

The short outage / short cycle strategy is an approach that Finland has perfected. Finnish outages average 15 days (they actually have alternating 10 and 20 day outages), and they operate very reliably during the cycle. From the Figure 1.1 we predict that their capacity factor should approach 96%. In fact, it is around 93%, which is outstanding compared to world performance. [Ref. 8] There are underlying conditions allowing the Finns to achieve such short outages. First, they have a highly skilled labor force which returns around 90% of its outage force annually. This assures that outage personnel are familiar with the plant and require minimal or no training annually. Second, their plants were designed for ease of maintenance. For example, they have extra laydown space, which is at a premium in US plants. Third, they fully utilize specialized tools to speed up the outages. Finally, they have outstanding planning. All of these factors allow them to achieve very short, but highly effective outages. [From interview with Finnish utility representative, coded U27.]

As a counter example to the effectiveness of the short outage, short cycle approach, consider Japanese outages. Like the Finns, the Japanese are on an annual cycle and run extremely reliably between planned outages. However, the Japanese have very long outages relative to the Finns - around 80 days. This is partially due to regulatory requirements that force them to do more maintenance than may be necessary on an annual basis. But clearly significant gains in capacity factor could be realized in Japan by extending cycle length, and keeping the outage duration at 80 days.

1.3.2 Long cycle strategy

For typical major outage times on the order of 55 days or longer, it makes very much sense to increase the period between major outages to greater than one year, and possibly up to five years. Note, however, that there is a saturation effect. The gain is very flat past about three year outage periods. A note of caution about this figure. It is drawn to illustrate how capacity factor changes vs. cycle length for a GIVEN outage duration. In reality, the outage duration may increase (or decrease) as cycle length increases.

Consider the example of Pickering 7 - a CANDU plant owned by Ontario Hydro. Pickering 7 recently ran for 894 days straight - a new world record.[Ref. 9] This is nearly two and a half years, and is in line with the cycle lengths that should be considered in future designs. The ultimate goal of this line of research is to design a plant capable of doubling Pickering 7's performance.

1.3.3 Effects of running better during the cycle

Up to this point, the maximum hypothetical capacity factor (MHCF) was considered. MHCF is the capacity factor the plant would achieve if it ran perfectly during the cycle, and the only down time was due to the planned outage. Let us look at the effect of improving operating capacity factor (OCF). The operating capacity factor is the capacity factor achieved by the plant during the cycle. It is defined as the electricity produced during the operating cycle divided by the electricity that could have been produced if the plant ran at rated capacity 100% of the time during the operating cycle. Figure 2 plots the affect of OCF on overall capacity factor for a 55 day outage, as a function of different cycle lengths.

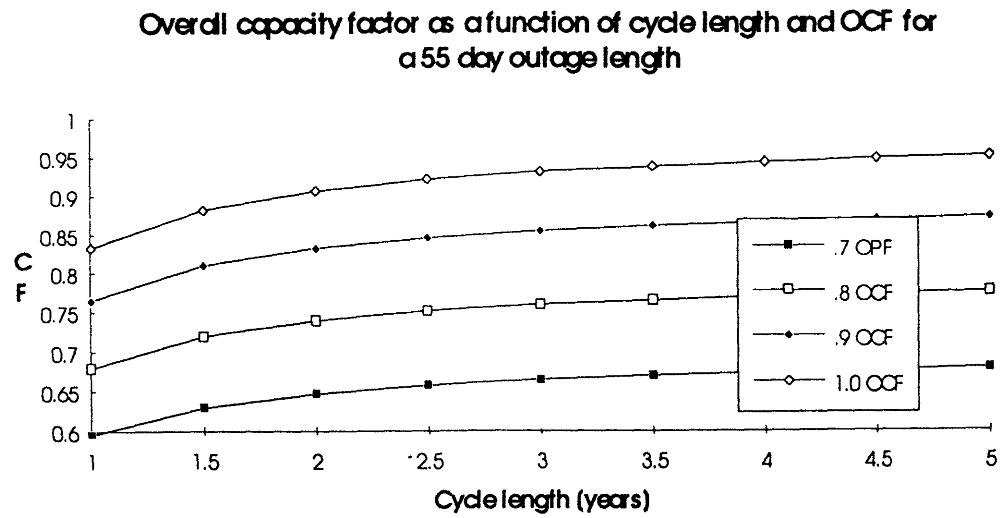

Figure 1.2

What Figure 1.2 shows is that it does not matter how long the cycle length is if the plant does not run well during the operational period. A 55 day outage is certainly achievable, even for 2 year cycles. But what is seen in Figure 1.2 is that when the operational availability hovers around 80%, the capacity factor is constrained to 70-75% even for increasing cycle lengths. This confirms the previous hypothesis that improving operational availability can significantly improve capacity factor and nuclear power economics.

As previously mentioned, reducing outage duration is beyond the scope of this research. Outage management is already being addressed by many experts. However, it is worth noting that the methods utilized for improving operational availability and increased cycle length may decrease outage duration. Take the specific example of the Pilgrim nuclear power plant. Pilgrim's critical path item is their ECCS. [Utility representative, coded U19]. Pilgrim has only 2 independent trains, both of which must be maintained during the refueling outage. The ECCS maintenance requirements dictate the length of the outage and the cycle length. By designing for extended cycle length, the capability to surveil, test, and maintain this system online would have to be addressed. As such, this critical path item will be removed from the outage scope, and the outage is free to decrease to the next most limiting challenge. In essence, two difficulties, extended cycle lengths and a critical path outage item, are dealt with by one strategy – online surveillance, testing, and maintenance.

1.4 Research directions

The problems limiting capacity factors have been delineated. The next task is to identify the areas where research needs to be performed to achieve a higher capacity factor through an extended operating cycle. As shown in Figure 3, the natural division is between fuel cycle physics and plant engineering:

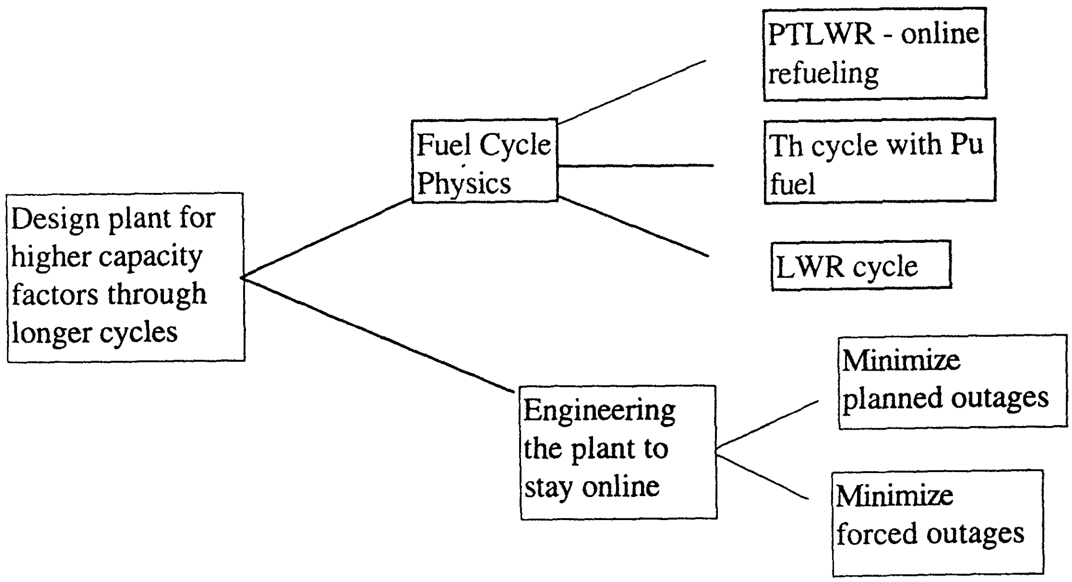

Figure 1.3 - Research directions

This report is concerned with designing the plant to accommodate whichever fuel cycle / reactor combination is chosen. In the subsequent chapters, a strategy is developed to suggest advantageous system alignments and modifications, and analysis techniques will be identified and utilized to predict the effects of modifications on plant performance. For now, focus is in the plant engineering direction. It is desired to design power and support systems capable of operating reliably for extended periods of time. Although the specifics of the fuel cycle and reactor type will affect the design and requirements of certain of plant systems, initial focus will be on those systems common to the different reactor types; specifically, the power production systems such as feedwater, steam supply, condenser, turbine, reactor coolant pumps, service water, and other continuously operating systems.

Chapter 2 - Strategy for improving capacity factor

Several areas were identified in Chapter 1 of having potential to increase capacity factor. Those areas were shorter outage duration, longer cycle length, and improved operating cycle performance. From these broad areas for improvement, several potential strategies emerge which will be discussed in this section.

One of the goals of the plant operator and plant designer is to find ways to minimize unavailability. A general approach to accomplishing this goal is to be able to perform required critical activities (monitoring, inspection, calibration, maintenance, and repair)

- at higher modes of operation (closer to full power)
- quicker
- less frequently.

Modes of operation are generally defined as follows. Mode 1 is defined as power operation. The plant is typically producing greater than 15% power. Mode 2 is defined as startup/low power operation. The plant is operating at less than 15% power. Mode 3 is defined as hot standby. The plant is at less than 3% power, but is close to critical. Mode 4 is defined as hot shutdown. The plant is still in hot conditions (between approximately 260 °C and 290 °C for a PWR), but all rods are inserted into the core, and the reactor is subcritical. Mode 5 is defined as cold shutdown. The plant primary temperature is below approximately 93 °C. Mode 6 is defined as refueling shutdown. The plant primary temperature is below approximately 65 °C, and the primary system is open.

2.1 Moving monitoring, inspection, calibration, maintenance, and repair to higher modes of operation

The first strategy for improving capacity factor is shortening the amount of time spent out of power production modes. While in lower modes of operation, less or no electrical energy is produced. This reduces revenues and profits, as discussed in Section 1.2. It takes increasing amounts of time to go to and return from progressively lower modes of operation, resulting in additional profit losses.

2.1.1 Power maneuvering

Nuclear power plants can typically change power at a rate of 5% per minute without exceeding technical specification limits. Therefore, the time loss associated with maneuvering between power states is small compared to the time required to maintain the lower power level for monitoring, inspection, calibration, maintenance and/or repair.

2.1.2 Maneuvering between full power and hot shutdown

Although a nuclear power plant can go from full power to hot shutdown in a matter of seconds as a result of a reactor trip, the subsequent transient may cause safety setpoints to be exceeded, resulting in a safety system actuation. Therefore, it is desirable to approach shutdown in a controlled manner. As stated, power can be increased or decreased at a rate of 5% per minute - the plant can go from hot standby to full power in a matter of minutes. In practice, maneuvering plant power is rarely this simple, but as a first approximation, assume that the time required to get between full power and hot shutdown is short. Therefore, most of the lost electrical generation comes from the time to restore (repair) the plant to its functional state.

2.1.3 Moving from hot shutdown to cold shutdown

The time required to bring the plant from hot shutdown to cold shutdown is not negligible. The maximum primary system heatup and cooldown rates are 100 degrees Fahrenheit per hour. This is set by the thermal stresses put on the reactor vessel. Therefore, it takes a combined minimum of a half a day to cooldown and heat up, ignoring time spent in cold shutdown. In actuality, heatup and cooldown are performed slower than this. Intermediate states and steps slow the rate at which the reactor approaches power operation. Therefore, it is assumed that a combined period of at least two days is required to cool the plant down from power to cold shutdown conditions and then to heat the plant up to return to power operation.

2.1.4 Moving between cold shutdown and refueling shutdown

In the refueling shutdown condition, the primary system has to be opened. The reactor must be cooled further (typically under 150 °F) and the plant must be put in the refueling shutdown condition. Opening the primary system requires breaking the pressure boundary and requires laborious effort to insure proper controls are observed from a safety and radiological perspective. It is assumed that the additional controls contribute to add a combined week in going into and out of refueling shutdown conditions, starting from cold shutdown.

2.1.5 At power monitoring, inspection, calibration, maintenance, and/or repair

It should be obvious that the value of avoiding lower modes of operation is real and significant. It was indicated in the industry interviews that if all critical activities could be performed at power without degrading safety, then capacity factor would be increased substantially. Major outages would be reduced to refueling outages only - a maximum of about 20 days. This may be unrealistic, but the value of online maintenance becomes apparent.

However, industry interviews also expressed some reservations about performing all or most critical activities at power. Representatives from all backgrounds expressed reservations over the impacts on safety of performing more activities at full power. For example, when a system is taken out of service for repair, it is unavailable for safety applications until it is returned to service. If careful consideration is not given, this can increase the overall risk associated with the operation of the plant.

2.1.6 Strategy matrix for monitoring, inspection, calibration, maintenance, and repair at higher modes of operation.

Thus, Figure 2.1 suggests strategies for approaching standby safety system maintenance. The location of the item in the grid shows the typical conditions under which the given operations are currently performed. The arrows signify where it is desirable to perform the given operations. For the specific example of the standby safety system that is inspected at cold shutdown conditions to verify its operability, two strategies are suggested. First, it is desirable to perform the inspections closer to full power. Second, it would also be advantageous if monitoring could be used to verify the operability in place of inspection, and at higher modes of operation. The matrix also suggests performing maintenance and repair for these systems at higher modes of operation.

Performance of these activities at full power could result in savings in two areas. First, if safety system inspection, maintenance and repair are critical path outage items, then performing these activities at power could decrease outage duration. Second, if the standby safety system limits cycle length, performing these functions at power allow extended operating cycles without requiring additional costly outages.

	Monitor	Inspect	Calibrate	Maintain	Repair
Full Power	Desired	Desired		Desired	Desired
Reduced Power					
Hot Standby					
Hot Shutdown					
Cold Shutdown		Present		Present	Present
Primary System Opened					

Figure 2.1 - Monitor, inspect, calibrate, maintain and repair in higher modes of operation - standby safety system as an example

2.2 Shortening repair time (MTTR)

The second strategy involves decreasing the mean time to repair. This applies to operations, unplanned outages, and major planned outages. The mean time to repair can also be thought of as the mean time to perform required monitoring, inspections, calibration, maintenance, and repairs. In short, it is the average amount of time required to return the entity to the desired state or to verify that the entity is already in the desired state. The time required to repair a component or system directly affects capacity factor. When a component important to safety fails, the plant is put in a limiting condition for operation. If that component is not repaired within a specified period of time, the plant will be required to go to a lower power or a lower mode of operation, resulting in economic losses for the utility. In other cases, a failure may result in an immediate loss of power. In both cases, it is economically advantageous to repair the component or system as fast as possible.

Figure 2.2 illustrates the value of performing required activities quicker. The location of the item on the grid indicates the approximate duration of time required to return the item to its functional state. The arrows indicate the direction for improvement.

The example given illustrates that major turbine-generator inspection and repair can take months. Figure 2.2 suggests that online monitoring may take the place of some inspections. It shows that investing in better inspection techniques may provide savings. Figure 2.2 also suggests that measures taken to reduce repair times (such as keeping a spare rotor or spare parts in stock) can be advantageous.

This strategy does not only apply to turbine-generators nor only to monitoring, inspection and repair. Decreasing the time required to calibrate and maintain components can increase availability and/or reduce manpower requirements.

	Monitor	Inspect	Calibrate	Maintain	Repair
Online	Desired				
Hours					
Days		Desired			Desired
Weeks					
Months		Present			Present

Figure 2.2 - Shorten time to return item to functional state - turbine/generator as an example

2.3 Extending the periodicity of activities - increasing the mean time to failure (MTTF)

The final method available to improve plant performance is extending the required periodicities of monitoring, inspection, calibration, maintenance and/or repair. Mean time to failure is a parameter used to capture all of these activities. Perhaps a better word would be mean time to unavailability or mean time until attention is required. Regardless, if entities can go longer periods before they require attention, then the plant capacity factor will be increased, and cycle lengths can be increased. Therefore, increasing the mean time to repair of components within plant systems can affect economics.

Figure 2.3 suggests increasing the mean time to required attention as a strategy to improve overall reliability. The arrows show the current relation between periodicities of required activities of a given item. The arrow suggest increasing the periodicities. In this example, strategies for increasing the mean time to inspection and maintenance of the low pressure turbine is examined. Current low pressure turbines require major inspections and maintenance approximately every five years. The scope of low pressure turbine inspection and maintenance is enormous, and the time required to perform this is large. Many people believe that on a five year major outage cycle, if all three low pressure turbines have to be inspected and maintained, turbine maintenance will dictate the length of the outage.

Therefore, reduction of required low pressure turbine inspections and maintenance is key to longer cycles.

	Monitor	Inspect	Calibrate	Maintain	Repair
Five years		Present ↓		Present ↓	
Ten years		Desired		Desired	

Figure 2.3 - Increase time between shutdowns - turbine/generator as an example

2.4 Example - Implementation of the strategy to steam generators

The purpose of the following section is to demonstrate by example how the strategies implied by the previous section can be used to help synthesize engineering solutions to real problems. As discussed in detail in Chapter 3, interviews were conducted with industry representatives to identify issues regarding achieving higher capacity factors through longer operating cycles. One of the sections describing a problematic component identified during the interviews, which fits equally well in Chapter 3, is presented in this section to illustrate the strategies of Sections 2.1 - 2.3. (A1, A2...; C1, C2...; N1, N2...; P1, P2...; U1, U2...; V1, V2... are codes used to shield the identity of the commentor. Additional codes are used to protect the identity of plants, when disclosure could identify commentor. See Chapter 3 for the key regarding the generic origin of the comment.) Section 2.4 includes the following:

- results of interviews identifying the steam generator as a problem component
- discussion of the strategies to be applied to the steam generator
- matrix of proposed design changes based on the strategies.

2.4.1 Interview results regarding steam generators

When asked about the most limiting factors in going to longer cycles or running more reliably, the most popular response - by far - was the steam generators; therefore, steam generator design is an issue worth examining in detail. The most prevalent steam generator design is the U-tube. For a more detailed description of this device, see [Ref. 10] and [Ref. 11].

The following is a summary of the comments made concerning steam generators during interviews with representatives from the nuclear industry.

2.4.1.1 Issues/new problems concerning steam generators

2.4.1.1.1 <u>Steam generator tube ruptures</u>
The probability of having a steam generator tube rupture in a PWR is about 0.02 / yr. If the tubes are not inspected or repaired periodically, however, the frequency of tube ruptures may increase. Tube ruptures are currently low contributors to the expected core damage frequency because the plant can usually repressurize, isolate, and shut down

safely, following a steam generator tube rupture. Nevertheless, tube ruptures are not insignificant from a safety perspective, and are a serious economic risk. (U20) (U4)

The safety and economic risks from an increased probability of steam generator tube rupture from longer operation and decreased inspections should be analyzed.

2.4.1.1.2 Multiple tube ruptures

There was recently concern that a main steam line break could cause multiple steam generator tube ruptures due to the degraded states of the tubes and the resultant high pressure drop across them. However, NRC has found that in this event, the pressure drop across the tubes is insufficient to cause multiple ruptures of degraded tubes. (N1)

An analysis by Maine Yankee supports the conclusion that a main steamline break would not cause multiple tube ruptures. [Ref. 29]

Consequently, multiple degraded tube ruptures due to a main steam line break are not currently limiting, but should be considered for longer cycles.

2.4.1.1.3 Utility perspective

Tube integrity and support plate problems are key to running longer and improving capacity factor. The advanced reactors have improved materials and chemistry; have reduced hot leg temperature; and have incorporated past experience. The performance of replacement steam generators should give some indication of how redesigned steam generators may perform in the future. (P4)

Steam generator tube leaks are also a big concern to utilities, and may be the limiting factor in going to longer cycles. If tubes are not inspected periodically, there may be a tube rupture, and this can have serious impacts on capacity factor and operations. (C2) (U11) (C4) (U4)

2.4.1.1.4 Regulatory perspective

Steam generator tubes are a limiting problem in extending cycle lengths. NRC would be skeptical of running a plant five years without inspections, even if all of the problems were believed fixed. The NRCs position is that the utilities might as well plan on having problems with the steam generators. (V2) (N2)

If a plant has a problem steam generator or if there are indications of degradation, then there may be a regulatory requirement to inspect and plug or sleeve tubes on a specific schedule that is less than the cycle length. If there is a history of leakage, NRC isn't going to permit longer operating cycles without inspections. (V2)

2.4.1.1.5 New problems

There are new tube degradation mechanisms being discovered all the time (every 5 years or so). PWR_#6 and another plant recently had tube ruptures between the support plate, which is a new problem. (C4) (N2)

2.4.1.1.6 Aging
Steam generator degradation is a function of the age of the generator. There has to be sleeving and plugging done to maintain the primary system's integrity. (U20)

2.4.1.1.7 Planning for problems
Significant savings could be achieved by planning to replace the steam generators in the design phase. Maintenance capabilities should be considered when designing the steam generator. (N1) (V1)

2.4.1.2 Steam generator redundancy and loop isolation valves

2.4.1.2.1 Redundant loops for online work
Redundancy can be designed into the steam generators. Loop stop valves can be used to isolate one loop of the reactor coolant system to allow inspections, maintenance and repairs while the rest of the plant is at power. The design would be for N-1 loop operation - four 33% capacity loops, five 25% capacity loops, etc. This is advantageous because it is not necessary to shut down the plant and open the primary system when a tube leaks or to do required inspections and maintenance. The Russians have 6 loops, and may have done this. It probably wouldn't make sense to have a design where power would have to be reduced to do the inspections and maintenance, because the economic incentive is lost. (U11) (C4) (V2) (C2)

The downside to designing to isolate and drain one loop during operation is that complexity and maintenance burden are increased. There are now more tubes, pumps, and valves to fail and maintain. Further, the additional complexity translates into additional costs. It is expensive to add an extra loop or extra capacity. (P3) (C2) (U11)

2.4.1.2.2 Safety issues associated with online work
The capability to use valves to isolate a reactor coolant system loop is not out of the question. The Navy has loop stop valves, and the NRC staff has accepted them. They can be made reliable enough to prevent an accidental LOCA. (N2)

However, if it is desired to do online loop maintenance, multiple valves become necessary to prevent a large LOCA and for safety of personnel. If there are two valves is series, they can be tested for leakage by measuring the pressure between them.

From a maintenance perspective, personnel are in containment with the potential for an accident, so it may not be safe for the workers, and it also raises containment isolation questions. (U20)

2.4.1.2.3 Shutdown maintenance
Having isolation valves is also a good way to isolate the steam generators after shutdown. Isolation valves eliminate the need to construct nozzle dams to keep water out of the steam generators. Nozzle dams tend to leak and they are not designed to withstand much

pressure. If there is any sort of pressure transient, the dam will leak or fail. With isolation valves the steam generators can be accessed earlier in an outage, with less probability of leakage. (V2) (U13)

Loop stop valves are desirable for steam generator maintenance because the plant does not have to go to mid-loop as often as in other plants. Mid-loop operation is a very risky condition because there is so little water inventory. (U13)

2.4.1.2.4 Stop valves under tube rupture conditions

PWR_#2 has loop stop valves, but in the event of a tube rupture, the plant has to equalize the pressure between the primary and the secondary before it can be ensured that the valves will close. PWR_#2's stop valves do not work well under high differential pressures. The stop valves are not in any of the emergency operating procedures or any accident sequences. (U20)

2.4.1.3 Materials and specifications

2.4.1.3.1 Material selection

Better alloys need to be chosen for the steam generator tubes. The new steam generators use Inconel 690, which has been shown to be a lot better than the old steam generator tubes, but NRC will not allow five years of operation without inspecting the tubes. Surrey and Turkey Point should have good data on Inconel 690 performance. Inconel 690 is probably the best material available, but materials selection is still somewhat of an art-form. It may be advantageous to look at exotic materials for the tubes. Exotic materials may be much more expensive initially, but these materials would pay off in the long run.(U12) (U24) (C4) (V2)

2.4.1.3.2 Materials specifications / fabrication

In addition to material types, the specifications for the tubes are important. Excellent quality control (QC) over the fabrication of materials is absolutely necessary. Good construction techniques are also important. Full length tube expansion and the use of explosive expansion of the tubes in the tubesheet is superior to rolling the tubes and older techniques. The tubes should not be rolled because rolling leaves residual stresses and makes stress corrosion cracking a possibility. An important specification is the acceptable level of residual stresses. (U24) (V1) (U12)

2.4.1.3.3 Secondary side factors

Key elements to steam generator performance include not only good steam generator materials selection, but also secondary materials selection. The secondary system chemistry dictates the performance of the steam generators. A condenser with no in-leakage of brackish water is important so titanium condenser tubes should be used to avoid tube failures. Feedtrain materials selection is important, and copper and catalysts should be avoided. Finally, things like resin beads must be prevented from getting to the condenser. (V1)

2.4.1.4 Chemistry

2.4.1.4.1 Water chemistry

The most important factor in extending steam generator life is water chemistry. Nuclear plants have to gain control over the water chemistry - the industry has to be religious about it. With the new steam generator materials, and excellent chemistry, the steam generators can probably last over 35 years. The problem is very much quality control over the steam generator environment during repair and operation. (U24) (U21) (C2) (U11)

2.4.1.4.2 Sludge and sludge removal

The sludge pile sitting on top of the tube sheet is a disaster for the tubes. The high concentration of chemicals in the sludge eats away at the interface between the tubes and the support plate. The capability to sludge lance is important. The steam generator should have a good blowdown system with a procedure that will regularly get rid of the sludge pile. There should be a continuous online blowdown capability of up to 1% of full rated steam flow, and a high capacity blowdown rate of up to 10% full rated steam flow. (V1) (U21)

PWR_#1 does sludge lancing every outage. If the period between lancings is to be increased, the plant needs better steam generator and secondary side chemistry. (U21)

There needs to be pressure pulse cleaning capabilities. (V2)

2.4.1.5 Leak monitoring

There needs to be a better way to measure leakage to get more tolerance in leakage rate limits. The concern is that a tube will break before the plant can shut down, and that there will be a safety system actuation. If leakage can be monitored better, tube rupture becomes less of a risk. Online tube leak detection via main steamline radiation detectors (N-16) is possible, but it is very difficult to predict the magnitude of the leak. (V2) (C4)

When the plant passes the administrative leakage limit, it has to be shut down, and the tubes have to be inspected and repaired. (V2)

2.4.1.6 Inspections/repairs

2.4.1.6.1 Predicting tube conditions

Steam generator tube condition can be predicted based on prior inspection results. If better predictive capabilities were available, then the potential for extending inspections exists. An understanding of crack growth rates would be useful. (U21)

2.4.1.6.2 Industry experience with inspection

PWR#_3 takes three days just to inspect a steam generator (one steam generator per outage), not including cooldown or startup. A mid-cycle shutdown to inspect steam generators and maintain hard to reach components and satisfy surveillance requirements could be performed in about three weeks for a large plant. The plant could go up to three years between inspections. (U24)

PWR_#2 inspects 100% of all four steam generators' tubes every outage. It takes PWR_#2 30 days to inspect and repair a steam generator. Steam generator inspection is a critical path item for PWR_#2. (U13)

PWR_#1 tries to have refueling be the critical path item, but steam generator work borders the critical path. Technical specifications require 6% tube inspection via eddy current testing. PWR_#1 does 100% inspection of two steam generators every outage because of the plant's own concerns, not NRC's concerns. Some other plants are having mid-cycle inspections. On a 5 year cycle, 100% of the tubes would have to be inspected every outage, which would significantly increase the outage scope and probably its duration. (U21)

2.4.1.6.3 <u>Inspection</u>

There is a need for non-destructive evaluation (NDE) of steam generators to be done periodically to verify the integrity of the tubes. If there is not a refueling outage every two years, the steam generators can not be inspected on a regular basis. Eddy current testing isn't as good as plants would like; there is a need for better methods for tube inspection. There is nothing available yet for on-line testing of tubes. The reactor has to be in cold shutdown for inspection to occur. Ultrasonic techniques may yield better results than eddy current testing, but there may be drawbacks associated with them. (N1) (P3)

2.4.1.6.4 <u>Repair</u>

There are automatic machines that can do the repair, but they are susceptible to human errors also, because there is a human telling it what tube to fix. (U13)

2.4.1.7 Safety

From a risk perspective, a couple steam generators should be available during refueling until the head is removed (at which point natural circulation capabilities are lost). But from a maintenance perspective, this is not possible for PWR_#2 because the steam generators are on the critical path. (U13)

2.4.1.8 Summary

Section 2.4.1 outlines many of the issues associated with operating steam generators under extended operating cycles. Steam generator tube condition is a major economic and significant safety concern. The tubes must be inspected and repaired periodically to minimize the risk of tube rupture. Plant experience with steam generator tubes has been poor, and extending the period between inspections could increase the risk of tube rupture.

2.4.1.8.1 Traditional approach to improved steam generator reliability

Better materials, chemistry and workmanship may be a partial solution to increasing inspection periodicities without significantly increasing the risk of tube rupture. Inconel 690 is superior to current tube materials. Secondary chemistry is extremely important to steam generator condition. Sludge lancing and continuous blowdown can be used to improve steam generator chemistry and tube reliability. Tube expansion techniques and workmanship are important to reduce stress corrosion cracking. However, even with these precautions, the performance will still be unproven, and extended operating cycles may still not be accepted by NRC or the utilities.

2.4.1.8.2 Innovative approaches to improved steam generator reliability

An alternate approach is to design for online monitoring, inspection, maintenance and/or repair. This satisfies the first strategy for improving capacity factor listed in Chapter 2. Online leak monitoring can be used to predict incipient tube failures, which can potentially alleviate tube rupture safety concerns, but will not improve tube reliability. Other online monitoring techniques may be developed to monitor tube condition.

Loop stop valves can be used to isolate a steam generator during operation. With a steam generator isolated and extra capacity in the remaining operational loops, inspection and repair of steam generator tubes could be performed while the plant is at power. This approach will permit longer cycles by reducing tube rupture concerns. Safety issues include containment isolation limitations and isolation valve reliability.

2.4.2 Strategy for redesign of steam generators

2.4.2.1 Current state of steam generators

The current state of steam generators has just been outlined. Steam generators have become high maintenance items, requiring long periods of time in cold shutdown conditions for inspections, maintenance, and repair. The frequency of required inspections, maintenance, and repair depends on the history of the steam generator, but is typically once every 3 or 4 years per generator. Finally, 100% inspection and repair of a single steam generator takes approximately 30 days.

2.4.2.2 Strategies for steam generator activities at higher modes

Figure 2.4 shows the current state of steam generator operation. The figure shows that currently, steam generators are inspected, maintained, and repaired with the primary system cold and open. Also shown is that it would be advantageous to perform inspections, maintenance and repairs at higher modes of operation. Further, it would be advantageous if tube conditions (such as crevice chemistry or leak rates) could be continuously monitored online to predict when more detailed inspections, maintenance or repairs are necessary.

	Monitor	Inspect	Calibrate	Maintain	Repair
Full Power	Desired	Desired		Desired	Desired
Reduced Power					
Hot Standby					
Hot Shutdown					
Cold Shutdown					
Primary System Opened		Present		Present	Present

Figure 2.4 - Steam generator inspection, maintenance and repair at higher modes

Figure 2.5 shows that steam generator tube inspection, maintenance and repair take on the order of months to perform. If inspection, maintenance and repair could be performed quicker, they would no longer be critical path, could be done all in the same outage, and the operating cycle could be extended.

	Monitor	Inspect	Calibrate	Maintain	Repair
Minutes		Desired			Desired
Hours					
Days					
Weeks					
Months		Present			Present

Figure 2.5 - Shortening steam generator tube inspection, maintenance and repair

Figure 2.6 shows that steam generators are inspected every three to four years. If the period between inspection, maintenance and repair could be extended, then for a longer cycle, the steam generator inspections, maintenance and repair could still be staggered. Under a staggered strategy, only half of the steam generators undergo inspection, maintenance and repair every outage.

periodicity	Monitor	Inspect	Calibrate	Maintain	Repair
3 years		Present		Present	Present
4 years					
5 years					
6 Years					
7 years	Desired	Desired		Desired	Desired

Figure 2.6 - Periodicity of steam generator tube inspection, maintenance and repair

2.4.3 Addressing the steam generator problem

The previous strategies were used to synthesize proposed design solutions which could help solve the listed problems to various extents. The hypothesized options for steam generator redesign are included in Table 2.7. The perceived advantages and drawbacks are listed along with each option. An explanation of each option follows.

2.4.3.1 Option 1

Option 1 is the reference design. It can be considered a typical steam generator in and operating plant. It has Alloy 600 tubing, which is particularly susceptible to stress corrosion cracking. Industry experience indicates that long term tube performance is poor, and steam generator replacement is likely.

2.4.3.2 Option 2

Option 2 includes many of the current proposed solutions to the steam generator problem. These steam generators are expected to achieve better performance in terms of reduced corrosion and reduced inspection, maintenance, and repairs. However, there is no guarantee that all contingencies will have been accounted for. As such, there is a chance that the steam generators will not be able to run for extended cycles without inspection, maintenance or repair. Further, without operating experience, NRC will not accept longer periods between inspections. Therefore, the economic risk of designing the rest of the plant for longer cycles with the uncertainty associated with steam generator tube degradation is too great.

2.4.3.3 Option 3

Option 3 uses the same features as option 2, but includes the capability to monitor tubes online. This is a relatively cheap method that could be used to satisfy NRC inspection concerns. If the monitoring system is exceptionally good, then steam generator inspection requirements may be reduced significantly possibly reducing outage durations. However, if NRCs concerns were founded, the steam generator will still require frequent maintenance and repairs.

2.4.3.4 Option 4

Option 4 also incorporates the features of option 2 to improve steam generator performance. In addition, loop isolation valves are incorporated in the design of the reactor coolant system. Each of the loops (typically 4 for a large PWR) is equipped with additional capacity such that if one loop is isolated, the reactor will be able to run at 100%. Further, while the loop is isolated, inspections, maintenance and repairs could be performed on a steam generator. This capability can completely remove steam generator (and reactor coolant pump) maintenance from the outage scope. This has the potential to significantly reduce outage duration and manpower.

Two problems are apparent with this strategy. First, the additional capital cost may be overwhelming. Second, if workers are required to perform inspections, maintenance, and repairs inside containment while the plant is running, their safety and public safety could be jeopardized. If an accident occurred with workers in containment, containment isolation may be jeopardized and workers may be injured.

Two additional strategies can be used to minimize previous risk. First, if the online monitoring system of option 2 is also incorporated into the design, time consuming inspections may be reduced, and the frequency that the steam generators are isolated could be reduced. Second, if a remote robotic system for inspections, maintenance and repairs is incorporated into the design, human time in containment would be reduced.

2.4.3.5 Option 5

Option 5 is similar to option 4, but the reactor coolant pumps and steam generators are located outside containment. There are several benefits to this design. First, the size of the containment could be reduced, with a significant capital savings to the utility. Second, the personnel safety and containment isolation questions are eliminated by design. Third, there is much more room to perform maintenance, and fewer contamination concerns. This can decrease inspection, maintenance and repair times (strategy 2). Fourth, by making the isolations valves very reliable and capable of closing under high differential pressures, pump seal LOCA and multiple steam generator tube break concerns could be eliminated. Finally, the steam generators would be much more accessible for replacement.

Drawbacks include radiological concerns outside of containment, although this is a common concern in BWRs. Also, there may be additional capital expenses associated with housing the steam generators and making isolation capabilities sufficiently reliable.

2.4.4 Summary

Section 2.4.4 is devoted to illustrating how the strategies developed in Sections 2.1 - 2.3 can be used in conjunction with industry experience to generate targets for improvement. Steam generators were used in this example because they represent a chronic component, potentially limiting cycle lengths and capacity factor. Industry experience garnered from interviews is outlined. Strategies for less frequent and online monitoring, inspection, and repaired suggest innovative methods to decreasing the impact of tube degradations. Strategies for reduced steam generator repair and replacement time are also examined. The various methods are analyzed based on their expected benefits and drawbacks.

As a result of this effort, three innovative solutions are developed. The first uses online monitoring to replace inspection requirements. The second includes the capability to isolate a steam generator for online maintenance and repair, but raises safety issues. The third locates steam generators and reactor coolant pumps outside containment for ease of maintenance and replacement.

Strategy	description	benefits	drawbacks
(1) Base design - no modification	standard design		1. Extended outages 2. Possible mid-cycle outage/limit cycle length 3. difficult/expensive to replace steam generators
(2) Standard design solutions [Ref. 12]	1. Alloy 690 tube material 2. modified tube supports to reduce fretting 3. explosive tube expansion 4. periodic chemical cleaning 5. high pH chemistry 6. redesigned support plate 7. design for easier replacement 8. higher blowdown capacity to remove sludge	1. increase in steam generator performance 2. potential increase in time between inspections, maintenance and repairs	1. Would require experience before accepted by NRC for longer cycles. 2. no guarantee of eliminating al problems 3. still may require expensive steam generator replacements
(3) Online monitoring	Same as (2) except online monitoring of tube condition by monitoring tube crevice chemistry and/or crack development	1. moderates or eliminates NRC inspection concerns 2. reduce inspection requirements 3. relatively cheap	1. If concerns were founded, then still have to shut down to repair 2. expensive and difficult to replace steam generators
(4) Online inspection & repair	1. valves to isolate steam generators and pumps 2. n loops, with 1/(n-1)*100% capacity per loop 3. possibly robotic inspection / repair 4. characteristics listed under (2) and possibly (3)	1. online inspection / repair 2. shorter outage times 3. longer operating cycles 4. may eliminate pump seal LOCA considerations	1. expensive to construct 2. expensive and difficult to replace steam generators
(5) Online, easier inspection & repair, easier replacement	Same as (4) except 5. steam generators and pumps outside containment [Ref.13] 6. ability for human inspection / repair	Same as (4) except 6. easier and cheaper steam generator & pump replacement and repair. 7. roomier or smaller containment	1. expensive to construct 2. containment isolation concerns

Figure 2.7 - Alternative steam generator design improvement strategies

2.5 Summary

In this chapter, three strategies were identified to guide in the redesign of problematic systems or components. They were

- design for monitoring, inspection, calibration, maintenance, and repairs at higher modes of operation;
- design for shorter down times associated with monitoring, inspection, calibration, maintenance and repair; and
- design for extending periodicities of required monitoring, inspection, calibration, maintenance, and repair.

Next, the results concerning steam generators from interviews conducted with a range of organizations associated with nuclear power generation were summarized. These results were then used in conjunction with the strategies to synthesize proposed design modifications that would remediate - to different extents - the concerns about steam generators vocalized during the interviews.

Chapter 3 - Interviews with industry representatives

The first step in designing power plant systems is a review of current operating experience to learn of shortcomings and/or strengths of existing designs. This ensures that the pitfalls of past mistakes are avoided while current operational experience is exploited.

With this in mind, a diverse group of knowledgeable individuals were interviewed to identify factors that may inhibit extending the operating cycle to up to five years and/or running more reliably. Interviews were conducted with 55 individuals from utilities - PWR, BWR and CANDU; vendors - General Electric, Westinghouse, and ABB/Combustion Engineering (ABB-CE); consulting firms; academia; the Nuclear Regulatory Commission (NRC); and industry organizations - the Institute of Nuclear Power Operations (INPO), the Electric Power Research Institute (EPRI), and the Nuclear Management Resources Council (NUMARC). Their comments encompassed a myriad of technical, regulatory, institutional and regulatory obstacles. In addition to suggesting areas where difficulties may arise, they also offered many helpful and innovative solutions.

The purpose of this chapter to classify and outline important comments made during the interviews with industry representatives. Important generic issues associated with longer, more reliable plant operation are listed. This chapter delineates several general categories of concerns, and cites important concerns in each category. Information gathered regarding steam generators was transferred to Chapter 2, Section 2.4. Information cited represents only opinions of those individuals interviewed, but provides a valuable knowledge base.

Categories identified were:

1. Technical / Hardware Concerns
2. Regulatory / Institutional Framework
3. PRA in Design
4. Design Principles
5. Economic Pressures
6. Operation and Maintenance Practices
7. Material Condition
8. Cycle Length Pressures
9. Advanced Concepts
10. Safety
11. Plant Size

To maintain anonymity while preserving information about the generic source and perspective of the commentor, each interviewee was given a code. Further, if it was thought that mention of a plant or utility name could be damaging or would jeopardize anonymity of the commentor, a code was assigned to the utility. The following key lists the codes

A_x	-Academia representative
C_x	-Consultant representative
N_x	-Nuclear Regulatory Commission representative
P_x	-Professional industry organization (INPO, EPRI and NUMARC) representative
U_x	-Utility representative
V_x	-Vendor representative
PWR_x	-PWR plant code number x
BWR_x	-BWR plant code number x
Utility_x	-Utility

3.1 Technical / hardware concerns

Virtually everyone interviewed commented on at least one plant system. These comments varied from observations, to complaints, to suggestions for future designs. This category of comments is of immense importance, as it addresses many of the fundamental design issues. Few systems are immune to complaints or suggestions. In the following discussion, important examples will be examined in detail.

3.1.1 Feedwater system

This system was chosen as the example case for analysis in Chapter 5. The suggestions made in this section will be utilized in Chapter 5 in conjunction with the strategies of Chapter 2 to address the redesign of the feedwater system.

According to one reactor designer, "the feedwater system is key to running at high capacity factors." (V3) The feedwater system has historically been a major cause of plant unavailability. It is not a safety grade system. As such, it was not given the detailed design consideration that it deserved. The following is a list of concerns expressed in the interviews regarding the feedwater system.

3.1.1.1 Typical system configurations

Experience with redundancy is mixed. Utility 1's practice is to have three 50% capacity feedwater pumps - 2 turbine and 1 mechanical. They still have had problems. BWR_#3 has three, 50% feedwater trains, and they haven't had many problems with their feedwater system. BWR_#3 has only had one loss of feedwater trip. (U12) (U2)

ABB-CE System 80^{+} was designed with redundant feedwater trains, which was not a significant cost compared to the cost of many of the other components. Current ABB-CE plants have two oversized feedtrains (two 70% capacity feedtrains), with both operating continuously. If one trips, the other goes to full speed and the reactor cutback system reduces power. (V1)

General Electric BWRs usually have three or four condensate pumps that boost the pressure to 150 psi, three to four condensate boost pumps that boost the pressure to 500 - 600 psi, and three to four main feedwater pumps that boost the pressure to reactor pressure (~1000 psi). The feedwater system should be designed so that it can provide 100% of rated flow with one pump out of service. The obvious configurations are three 50% capacity pumps or four 33% capacity pumps. (V3)

The feedwater system should be designed with redundant feedpumps for reliability and safety. (C2) (U11)

3.1.1.2 Feedwater control systems
The feedwater system has feedwater heaters which have their own control systems to control water level. The control systems deserve particular attention. (V3)

Typically, the feedwater pumps are not the weakness, the feedwater control system is the design weakness. (U12)

Feedwater regulation is a problem. If there are valve stem leaks, and regulation problems, the feedwater system requires manual control. Eventually, the reactor trips. Trips due to improper feedwater regulation are fairly frequent. There is a fair amount of work that goes into maintaining those valves. (U20)

Feedwater heating is key to effective steam generator water level control at low power (less than 15%). (A2)

3.1.1.3 Feedwater pumps
(See also Section 3.4.4 on auxiliary feedwater pump diversity)

Turbine driven feedwater pumps and electrical powered auxiliary feedwater pumps should be used. Turbine driven pumps will run reliably for a very long time. The problem comes when they are started fast in an emergency situation. They aren't fast start, quick response machines. The pumps need to be "tweaked" slowly to get them running just right. Therefore, electrical powered auxiliary feedwater pumps for fast start actions are more appropriate for fast start safety applications. (U12)

For BWRs, shielding should be provided so that maintenance can be done on turbine driven feedwater pumps without excessive radiation exposure. (U12)

The feedwater pumps in BWRs should be powered by electrical motors because turbine driven pumps use radioactive steam, and they tend to be located near the main steam lines. This is a tough environment to do maintenance in. Electrically powered motors are less efficient than turbine driven pumps, so a little efficiency is lost to gain maintainability. (V3)
Note the contrast with the first statement made above.

Magnetic bearing feedwater pumps: two magnetic bearing feedwater pumps have two years operating experience. That kind of technological evolvement can be very significant. Magnetic bearings theoretically have no wear. (U14)

Feedwater pumps haven't been a problem for PWR_#10 as far as running them longer is concerned. (U15)

3.1.2 Turbine-generator

3.1.2.1 Maintenance requirements

Typically, the turbine generator consists of one high pressure turbine and two or three low pressure turbines located on a common shaft with the generator. Major inspections and overhauls are currently required approximately every 5 years. Turbine maintenance may be staggered between outages to reduce work scope and time. If all turbine maintenance is performed at the same time, the outage length will probably be dictated by turbine inspection and maintenance (on the order of 100 days). Further, the utilities will have to convince themselves that the turbine and excitor can be run that long continuously without risk. Utilities and vendors are hesitant to extend the periodicity because the consequences of turbine blade failure or generator failure are high (witness Pilgrim, 1994 and Fermi, 1993). Utilities would have to convince insurance companies of the feasibility of running the turbines longer. Therefore, turbine inspection and maintenance requirements are thought to be a major limitation in going to longer cycles, and 5 years is thought to be pushing the limits between turbine inspections and maintenance. (U14) (U15) (V1) (V3) (U16) (U21) (N5) (P3)

However, recent developments have been made in turbine design. BWR_#4 purchased two low pressure turbines that are warranteed for 10 years - meaning they only have to do major inspections and maintenance on a 10 year schedule. The cost to replace the two low pressure turbine was $28M. The high pressure turbines can run for 5 years already, and do not take nearly as much time to inspect as the low pressure turbines, so they should not be limiting. Minor inspections may be able to be performed in hot standby. (U19) (U24)

3.1.2.1.1 <u>Degradation mechanisms</u>

Turbine blade erosion is a concern, especially for low pressure turbine blading. The primary thing to watch for is erosion. (U21) (U20)

3.1.2.2 Diagnostics/non-destructive evaluation (NDE)

There are now offline NDE techniques and online diagnostics that are currently being implemented that generate data and precursor information to mitigate failure consequences and almost predict when it is really necessary to inspect specific components (e.g. a bearing, a rotor, the generator, stator windings, etc.) (U14)

There are usually vibrations prior to failure. Monitoring systems for detecting vibrations are in place. Some units are designed to trip on high vibration of the turbine. But there may be spurious trips based on this alarm. (U21)

NDE techniques can be used to monitor fracture toughness and fatigue. The primary thing to watch for is erosion. Effectively monitoring turbine condition should not be a very difficult task. (U24)

3.1.2.3 Design solutions

3.1.2.3.1 Redundancy
The turbine generator will be a problem. One solution is to use twin turbine generators. They do this in the Swiss plants (Gosgen is the exception). With redundant turbines, the plant may be less susceptible to loss of load conditions. And the plants are much better off from a maintenance perspective. (C2) (U11) (V3)

3.1.2.3.2 Better design
If the utilities made it a requirement that the turbine run for over five years continuously, the design people would put in some extra design margin in the bearings and other components to achieve better durability and higher reliability to allow them to write a warranty for five years. There aren't any technological reasons why a turbine couldn't run for that long. (V3) (C4)

3.1.2.4 Turbine generator auxiliaries

The turbine generator auxiliaries are worth redesigning. There are simple, cheap components in the turbine generator auxiliaries that can cause a large loss of capacity - for example the hydrogen subsystem, the steam seals, stop valves, hydraulic control valves, the lube oil system, moisture separators / reheaters and the electro hydraulic control system. A little money spent on improving these systems can significantly improve availability. (C4) (V3)

3.1.2.4.1 Electro-hydraulic control system
The turbine could in principal have two redundant electro-hydraulic control systems with a bumpless transfer. At BWR_#3, the control system is electrical on startup and hydraulic for steady state operations. Switching from electrical to hydraulic control has caused many trips. If the hydraulic control systems on the turbine generator fails, the turbine generator will trip. So the hydraulic control system and the supporting systems have to be robust. (V3) (C4) (U2)

3.1.3 Condenser

3.1.3.1 Turbine steam bypass capabilities

The turbine steam bypass system re-routes main steamline steam from the turbine inlet to the condenser. This allows a main steam flow- turbine flow mismatch without plant trip. The bypass capability varies between plants. This system is useful in reducing plant trips on loss of load generator. High condenser bypass capabilities reduce the chance of a trip following a complete or partial loss of load on the turbine.

System 80$^+$ has a 50% capacity turbine steam bypass flow capability. With the reactor power cutback system, power can go down to 50% within seconds and not trip in the event of loss of load. (V1)

3.1.3.2 Chemistry

If the condenser leaks seawater, it corrupts the BWR primary (or the PWR secondary) system because of inter-granular stress corrosion cracking (IGSCC), and other problems with stainless steel. (V3)

3.1.3.3 Condenser retubing

Several utilities have had to retube condensers. When the tubes degrade, they start leaking. Sometimes the plant can be down powered to plug the tubes (depending on condenser design), other times the plant has to be shut down. As the tubes degrade the plant begins to experience chemistry problems on the secondary side, especially for a seawater plant. During a refueling outage, plants with degraded condensers do a lot of plugging and retubing. (U20)

BWR_#3 just had its condenser retubed. Until the condenser retubing, there had been a lot of saltwater leaks. The plant would constantly downpower to fix tubes. Sawdust was frequently added into the pump suction of the circulating water pumps every day to plug the holes in the condenser tubes. The new condenser tubes are titanium, which are expected to be much more reliable. (U2)

BWR_#4 has an titanium tube condenser, and has very few problems with saltwater in-leakage. BWR_#4 is one of the few saltwater sites without an intermediate loop to prevent saltwater in-leakage into the primary. The intermediate loop, which other BWRs have, is intended to provide a barrier between the saltwater coolant and the condenser, and, consequently, the primary system. At BWR_#4, one of the water boxes can be taken out of service for online maintenance. It involves de-rating the plant for maintenance. (U19) (V3)

3.1.4 Reactor coolant pumps (RCPs)

Current industry experience with reactor coolant pumps is mixed. PWR_#9 had a major outage recently because of loose reactor coolant pump bolts. Conversely, PWR_#10 has never had any problems with reactor coolant pumps. (U11) (U15)

ABB-CE uses a more forgiving reactor coolant pump design. They have better seals and seal cooling; a flexible coupling between the motor and the pump which eliminates some of the vibration that causes pump wear; and better bearing arrangements. Their pumps are purchased from KSB (German). Byron Jackson pumps are not as reliable. (V1)

3.1.4.1 Pumps seals

3.1.4.1.1 Opinions on the state of seals in the industry
In the early 1980s, plants were losing about 10 days of production capability a year due to poor reactor coolant pump seal performance or poor recirculating pump seal performance. A new set of specifications were put together by several utilities and a consulting company to improve the seal design, but the main improvements were in other areas. There was poor training, inadequate tools, insufficient spare parts, and inadequate procedures at the plants. Now reactor coolant pumps and recirculating pumps are running for five or six years without problems. The average lost time due to these seals is now under two days per year, and is much lower for the plants that do their maintenance correctly. The problem is not as significant. The lessons learned about seals can be applied to other pumps critical to operation. (C3) (U21)

Main coolant pump seals are elaborate multi-stage, controlled leakage devices, and they do wear. The solution is canned rotor pumps, but they cost more and are less efficient. (C4)

The limiting factor with RCPs is the mechanical seals. Depending on size, they run from 2 to 4 years. (V1)

3.1.4.1.2 Monitoring
PWR_#1 is now using trending of the leakage rate, and they typically rebuild or replace one reactor coolant pump seal per cycle based on the trending. (U21)

3.1.4.1.3 Seal cooling
There are two seal cooling systems: component cooling water system, and charging. If service water is lost, both of these systems become inoperable, and there is a risk of a seal LOCA. Therefore, in this design, the probability of a seal LOCA is the probability of losing service water. (U13)

3.1.4.1.4 Pump seal LOCA following loss of seal cooling and initiating event
One vendor analysis showed that their reactor coolant pump seals can operate post initiating event (transient) without seal cooling for the duration of the event, with a probability of a seal LOCA of 1 in 1000 (0.1%). But different vendor analysis could not support a similar conclusion, and it has to be assumed that the probability of a seal LOCA is unity, if seal cooling is lost during a transient. As a result, a large contributor to the expected core melt frequency in the second vendor's plant is a seal LOCA. Therefore, seal cooling is an issue worth investigating in more detail. (U13)

3.1.4.2 RCP motor maintenance

3.1.4.2.1 RCP motor maintenance frequencies
Typically, motor overhauls are done around every 5 years. Westinghouse RCP motors, called "smart motor," are self monitoring. They monitor vibrations and temperatures for

indications of degradation. The pump is shut down when one of the key parameters is out of tolerance, rather than at fixed intervals. (V2) (U11)

At PWR_#1, there is a preventive maintenance order to change out and rebuild the RCP motors every 10 years. PWR_#1 is questioning whether that is too frequent. They changed out one motor after seven years, and there were no indications of degradation. So the plant is not changing out the second one until 10 years. The last one will wait 14 years at the earliest. (U21)

3.1.4.2.2 Spare motors

Utility 3 is ordering a new RCP motor (at a cost of $2M) which is being built in Switzerland. Utility 3 decided to buy a separate RCP motor because the analysis showed that it's better to have a spare RCP motor than to be forced down without a spare. (C6)

PWR_#9 currently pulls one RCP motor every outage for maintenance and puts in a spare, which saves time. (U11)

3.1.5 Recirculating pumps (BWR)

The ABWR has 10 canned rotor recirculating pumps, but it only needs nine to run. There is significant maintenance required on the pumps every five years. It is possible to do two out of the 10 pumps every year, or four out of 10 every 18 to 24 months. For a 5 year cycle, all of the recirculating pumps would have to undergo maintenance at once, or they would have to be made more robust so that they could run for 10 years. The solution to the recirculating pump problem is to go to a natural recirculation design. (V3)

3.1.6 Safety systems

3.1.6.1 Emergency core cooling system (ECCS)

3.1.6.1.1 Online maintenance

To go to longer cycles, there must be the capability to do maintenance on safety systems online. The plant must be designed for N-2 safety train operation (have two extra redundant trains of ECCS to satisfy the single failure criterion) or the operator must be willing to enter limiting conditions for operation (LCOs) to maintain these systems online. As an example of N-2 redundancy, Gosgen (Sweden) has four trains of ECCS, and they only need two to provide 100% core cooling functions. Therefore, they can do maintenance on one system without significantly degrading safety. For LCO maintenance, the utility itself and then the NRC has to be convinced that LCO maintenance is safe. If a careful review is performed, LCO maintenance of safety systems can be performed safely. (U15) (C2) (U11)

System 80^{+} has 4 trains of ECCS. The fourth train is not an installed spare, but the Technical Specifications may allow online inspections and maintenance. The ABWR has a three division ECCS. The plant can write Technical Specifications that allow it to take one division down for maintenance for a certain period of time. These systems can already be maintained, as designed, so they are not a serious problem in going to longer cycles. (V1) (V3)

3.1.6.1.2 Online testing
System 80$^+$ has online testing of all safeguards pump, which traditionally had to be tested while shut down. ABB-CE has extended testing to full flow testing because previous tests were done at partial flow and then full flow predictions were extrapolated. The error and uncertainty due to extrapolation was sometimes very large. (V1)

3.1.6.1.3 Functional ties
System 80$^+$ has the ability to functionally exchange the shutdown cooling and containment spray pumps. This adds 2 additional pumps to the function of shutdown cooling or containment spray. It can be helpful to have pumps available from other systems as backups. (V1) (C2 / U11)

In past BWR designs, ECCS and RHR (residual heat removal system) have been mixed together. The RHR has a heat removal function and the same pumps are used for the core flooding function. (V3)

3.1.6.1.4 Safety limitations
PWR_#2 is the only PWR in the country that does not have accumulators. This makes it almost impossible to go to 24 month cycles because of peaking factors prior to LOCA.(U13)

3.1.6.1.5 ECCS designs with limited flexibility
BWR_#4 has an ECCS design that is highly inflexible for maintenance. There are two 100% capacity ECCS trains. Maintenance on either train of ECCS cannot be performed until the reactor cavity has been flooded during a refueling outage. To take one train out, non-safety systems have to be aligned to provide some form of redundancy. BWR_#4's ECCS drives their outage lengths. From this experience, it should clear that some form of alternate shutdown cooling capability must be designed into the reactor. The same principle applies to emergency diesel generators. (U19)

(See also Section 3.8.3.2.1)

3.1.6.2 Emergency diesel generators (EDGs)

3.1.6.2.1 Maintenance unavailability
Maintenance unavailability of the emergency diesel generators (EDGs) significantly increases the expected core damage frequency (CDF). An additional gas turbine can be added to supplement the diesels. (N1)

However, some industry representatives think it is sometimes best to fix EDGs online because they may be needed most when the plant is shut down. They argue that the probability that the EDGs will be called upon while being maintained is small enough to justify online maintenance. (U24)

BWR_#4 can currently have one of their diesels out for three days for repairs before they are required to shut down. They don't do major diesel overhauls online. This takes a couple of weeks, which would be too long from a risk perspective. (U9)

3.1.6.2.2 Maintenance strategies

System 80$^+$ has two diesels and one gas turbine, so it can have a diesel out for 2 weeks if necessary (in the Technical Specifications). CE plants used to be limited to 3 days. The PRA justified going to 2 weeks, and voluntary entry of LCOs was accepted by NRC. (V1)

PWR_#9 overhauls one diesel every other outage (every 3 years). It's often the critical path item. There is a requirement to do a 24 hour run after the overhaul. If there is a problem, they have to fix it, and that will push the critical path. Sometimes maintenance causes problems in the diesel generators, so PWR_#9 may be doing maintenance too frequently. (U11)

BWR_#4 has only two EDGs. Work on an EDG cannot begin until the refueling cavity is flooded. An extra EDG could help shorten their outages, and give more flexibility. (U19)

3.1.6.2.3 Fast start requirements

Diesel generators are big machines suitable for continuous operation, that have been required to start in 10 seconds, and be tested that way. Too frequent fast start testing of the generators wears them out. They don't need to start in 10 seconds. Starting a 4.5 MWe diesel in 10 seconds puts enormous stresses on it. If the plants could take a little more time in starting them, they could be made a lot more reliable and longer lasting. (U12) (U9)

3.1.6.3 PWR control rods / control rod drives (CRDs)

PWR_#10 has recently had problems with control rod drop times. Control rod drop time tests are required by NRC, but they could either be done online or at hot shutdown, so that capacity factor would not be significantly affected. The rods don't get exercised enough if the plant does not shut down periodically. Then crud builds up in a couple of orifices that affect the scram time. B&W has changed the design to cure the crud buildup. This is the type of problem that is hard to anticipate when going to long cycles. (U15) (N2)

3.1.6.4 BWR control rod drives

3.1.6.4.1 Maintenance

BWR control rod drives have to be rebuilt and refurbished periodically. A certain fraction are refurbished each year. In a longer cycle, a larger fraction would have to be refurbished each outage.(V3)

BWR_#4's control rod drives are never critical path. The control rod drives can be inspected very quickly. The outage staff tries to pick the worse 10% every outage and fix them, rather than fixing them arbitrarily. They monitor the temperatures and pressures to get an idea of their condition. (U19)

3.1.6.4.2 Control rod drive purge system

The control rod drive purge system keeps CRDs ready for scram. It keeps the accumulators charged, keeps the drives themselves filled with clean water, and keeps recirculating pumps filled with clean water. Its design is already sufficient - two 100% capacity pumps. (V3)

3.1.6.4.3 Control rod drive seals

Control rod drives have seals that require periodic maintenance. But GE is working on an advanced drive that does not have seals, but uses magnetic force across the pressure boundary as a coupling. "The current drive shaft with a seal is split, and a strong permanent magnet is attached to the portion within the pressure boundary. There is a mated permanent magnet coupling outside the pressure boundary but close enough to provide a holding torque higher than the stall torque of the drive motor (which is also located outside the pressure boundary). The design is expected to fit within the current geometric envelope. Commercial availability is a few years away, but feasibility has been proven." (personal correspondence with V3)

3.1.6.4.4 Conclusion

There should not be any trouble with the BWR control rod drives when going to longer cycles. There is a need for maintenance, but the track record is pretty good. (V3)

3.1.6.5 Containment

3.1.6.5.1 Containment leak rate tests

Containment leak rate requirements are 0.1% pressure drop per day, as specified in Appendix J. Utilities are continuously finding that some valve isn't quite as tight as thought, and they spend a great deal of time finding those valves and fixing them, but it's really not necessary. Plus, the mandated time scale for actuation of these valves is unrealistic. They are large, fast acting valves that have to be very reliable. But if the time scale was made more rational, the valves could be made much more reliable. (the time scale is currently under revision). (C8) (U12)

Check 10CFR50 Appendix J for containment leak test requirements. The regulations are being changed to make it a more reasonable test, but the requirement is not being done away with. NRC will begin giving plants relief on testing if they can show a history of successfully satisfying Appendix J requirements. (N2)

The law currently requires physical leak rate checks of the containment isolation valves every two years. At BWR_#4, some of the valves must be tested in shutdown conditions. The whole testing takes about two weeks if all the valves pass. However, if a valve exceeds allowable leakage limits, it has to be repaired. This could result in additional weeks added to the outage for a single valve. Some valves can be tested online, but if they fail, the plant still has to shut down to perform maintenance. Online testing of valves should be addressed in the design phase. (U5)

The utilities would like to see overall containment performance criteria rather than individual valve leak requirements. It's easier to test the whole containment rather than the whole containment AND each valve. This is a performance approach. (U9)

3.1.6.5.2 <u>PWR containment</u>

3.1.6.5.2.1 *Containment environment*
The containment atmosphere during operations is about 120 degrees F. Some of the equipment operates better at this temperature, too. It is very difficult for people to go into containment for extended periods of time. This places limitations on what equipment can be maintained online. (C2) (U11)

It is possible for people to enter containment while the reactor is running, but it is not pleasant. It is a harsh environment. (U20)

3.1.6.5.2.2 *Containment spray systems*
In a PWR, it may be better to make the containment spray systems manual start. If there is a fan cooler (in the heating, ventilation & air conditioning [HVAC] system), there is no reason for the containment spray to be fast start. Fast start of the containment spray uses up the stored water quickly. The containment spray may not need to be actuated in the first two minutes of an accident. It makes a big difference in the maintenance program and the reliability of components. If it is a fast start, automatic system, the equipment is continuously being beaten to death. Plus, there are a lot of things that have to happen coincident: pumps start, valves open, valves close. Therefore, there is a lot of logic circuitry to maintain. (U12).

The comment (U12) made above about using a manual start containment spray seems contrary to what I would think. It seems like manual start lends itself to operator error. A slow, phased, automatic start process may be the compromise.

3.1.6.5.2 <u>BWR containments</u>

3.1.6.5.2.1 *Drywell cooling system*
The drywell cooling system, starting with the ABWR, is designed with nothing in containment except the chiller heat exchangers and fans. The pumps are outside. There is a need to have redundancy for the fans in the containment. (V3)

3.1.6.5.2.2 *Containment atmosphere*
In BWR Mark I & II containments, personnel can not go into containment because it is inerted. The containment can not be de-inerted for safety reasons. To go into

containment, the plant has to be shut down. The Germans designed a BWR for online maintenance of the recirculation pumps, but scrapped it because of the inert requirement. (V3)

3.1.7 Residual heat removal system (RHR) - BWR and PWR

3.1.7.1 Online maintenance

It is important to be able to do maintenance online for the RHR system because it becomes critical during plant shutdown.(U11)

3.1.7.2 Combining safety and non-safety heat removal:

The RHR system is a safety heat removal system, but the plant generates heat in the non-safety portions also. The question is whether to combine the RHR system and the non-safety heat removal systems. Combining the two saves capital expenses, but reduces maintenance flexibility. If they are combined, the sea water system needs to be running all the time - during operation and shutdown - because the containment air conditioning has to be running continuously. That makes it difficult to do maintenance. The alternative is to: (1) have a non-safety grade closed cooling water loop for the non-safety grade heat removal, or (2) provide more redundancy in the safety grade loops. (V3)

The RHR pumps can be doubled up or taken out for maintenance. But the heat exchangers cannot be spared. (V3)

3.1.8 Heating ventilation & air conditioning (HVAC)

3.1.8.1 Inattention

The HVAC system always takes low priority in the design process; however, it is critical to short term reliability. It has an enormous impact on the reliability of solid state electronics and other key equipment. (U12).

3.1.8.2 Heating

For winter climates, if heating water goes out, it can shut the plant down. If the plant has a heating water system, the heating water system will create a significant maintenance program. (U12)

The secondary should be at least moderately protected from the elements and heated. (N6)

3.1.8.3 Fans

Belt-driven fans should not be used in the containment. The belts wear out and they are inaccessible. This can shut the plant down. (U15)

3.1.8.4 Ventilation of safety systems

PWR_#2 has no ventilation problems because all the ECCS safety systems are housed in one very big room. But PWR_#5 had to put everything in different rooms to meet separation, fire and flood requirements. There is not a lot of information on heatup of those rooms during post-initiating events. This is one of the big gray areas. So reliance on external cooling systems should be minimized, but this is very difficult to accomplish. (U13)

There is a plant that has a very risk significant ventilation system because it had a two pump system that supplied ventilation to almost everything in the plant. That came up as the most risk significant system in the plant. PWR_#5 has multiple systems to supply ventilation to the whole plant. (U13)

3.1.9 Instrumentation & control (I&C)

3.1.9.1 Control system capabilities
Plants should have control systems that are much more instrumented and more advanced. They should have at least 50% runback capabilities so that the plant does not have to depend so much on trips. (C2) (U11)

3.1.9.2 Calibration periodicities:
Utility 4 knows that they don't have to calibrate control systems or protective systems every refueling. They have 20 years of data that says to go to 2 year periods on the calibrations. It saves money and potentially reduces the risk of introducing problems. (U14)

If instrument readings don't drift apart, they're probably OK, but we test them anyway. (U4)

3.1.9.3 Online maintenance of control and protective systems
A utility is trying to push as much of the maintenance on control and protective systems online as possible, and is approaching this from a risk based perspective. In many cases, the best and safest time to do maintenance is online.(U14)

From an electronics perspective, online testing and calibration has already been done. Most (if not all) I&C has online testing done automatically in the System 80^+, or has simple, built in testing which does not require opening cabinets and putting jumpers on to test them. So the System 80^+ has eliminated those types of testings that often tripped the plant off-line or required it to be shut down. (V1)

There is a tremendous benefit to doing I&C surveillance online. (C6)

3.1.9.4 New instrumentation and control equipment
New I&C equipment is a lot less sensitive to problems. The digital equipment does not drift, and better monitoring and diagnostic techniques are available for this equipment. Some of the new I&C has not been specified yet in the new reactor designs because it changes so much. (C6)

The control systems are tremendously better and more reliable than they were 10-15 years ago. They are easier to test, have more online test capabilities than older systems. Control systems is the area to be least worried about when designing for longer cycles. (U20)

Controls are constantly getting better. The problems are the mechanical components they regulate. If they fail, the system fails. (U20)

3.1.9.5 Digital control

(See Section 3.9.3)

3.1.9.6 Instrumentation and monitoring

There are not any major problems with running any of the primary monitors longer. This includes thermocouples, differential level, differential pressure cells, pressure transmitters, neutron detectors (which are good for 10 years). The utilities have enough experience to know how to monitor them. (C6)

3.1.9.7 Cables

High voltage cables start to break down after 20 years. Regular surveillance tests do not indicate the overall condition of the cable, only if the cable is functional at that instant in time. The solution is to go to diagnostics that monitor the circuitry's electronic signature. (C6)

3.1.9.8 Designing against operator error

In the design stage, it has to be assumed that the operator will do the wrong thing. Controls should be designed such that the reactor is protected from the operators. (V4)

3.1.10 Valves

3.1.10.1 General concerns

3.1.10.1.1 <u>Valve maintenance and testing</u>

In general, valve maintenance and testing may be a limiting factor in going to longer cycles. Valves that operate frequently require more maintenance than those that operate infrequently. Redesigned valves may alleviate concerns over expanded maintenance. Valves experience hardening of grease which affects the torque that must be applied to the valve to shut it. (V1) (U16) (V2) (U21) (U24)

Motor operated valves are required to undergo force measuring to verify operability. The valves have to be out of service for force measuring. [Ref.30]

When valves remain shut for long periods of time, they can form chemical bonds and seal shut. (U9)

3.1.10.1.2 MOV testing under high flow conditions
A BWR has had problems showing that MOVs will close against high flow. It's hard to test the valves because there more or less needs to be a line break to generate that kind of flow resistance. (U2)

3.1.10.2 Safety valves

3.1.10.2.1 Safety valve testing
After two years safety valve settings drift and they need to be refurbished and reset off-line. (N1)

Safety valves are passive, and there is no particular reason to think that the valves would deteriorate and not tolerate a five year operating period. A safety relief valve manufacturer should be consulted to make sure this is correct. (V3)

Safety valves can not be tested online because that might initiate a LOCA. (V3)

3.1.10.2.2 ASME testing requirements
To meet ASME codes, a certain fraction of the safety valves are taken apart and run through an ASME test periodically. If they pass, there is no problem. If not, more testing has to be done. ASME rules will show whether it is currently acceptable to work on safety relief valves every five years. (V3)

3.1.10.3 Solenoid valves
The rubber / elastomer diaphragms in solenoid valve air and water systems are a problem. (C4)

3.1.10.4 Flow control valves
Flow control valves are a generic class of valves. Flow control valve performance is one of the biggest issues to address. (U12)

3.1.10.5 BWR main steam isolation valves (MSIVs)
BWR main steam isolation valves often don't pass their tests and have to be fixed every refueling outage. MSIVs can be tested online (late at night) by going to lower power and shutting one. But they may only be able to test their ability to close, not how much they leak. (C4) (V3)

BWR_#4's MSIVs can show up on critical path if they fail their leak rate tests. MSIVs are huge, and it costs about $150,000 to fix one of them. All containment isolation valves have to be tested every two years. NRC is about to give some relaxation on that requirement. If a plant has a good history with passing the tests (at least two passes in a row), NRC will start considering letting them go longer between tests. Maybe up to five years or more. (U19)

3.1.11 Circulating water system

The circulating water system removes heat from the Condenser. This system has had tremendous problems in the past. This system can be designed for longer cycles through redundancy. (V3)

Swedish plants have a spare circulating water pump for quick change-outs during outages. BWR_#4 has to rebuild their circulating pumps during the outage, which consumes valuable time and workers. The analogy applies to other pumps and other components. (U19)

BWR_#4 has had plant shutdowns due to rough ocean conditions. Debris accumulates at the intake screens, the circulating water pumps tripped and the plant tripped. (U23)

3.1.11.1 Seawater sites

At seawater sites, the circulating water system is more trouble because it brings algae, muscles, and bacteria into the system, causing additional corrosion and erosion. These problems have to be dealt with using better materials (titanium tubes for the condenser), or by putting in enough parallel piping for online repair i.e. instead of two pipes, use three - one inlet, one outlet, and one redundant for repair. (V3)

BWR_#3 had a problem with seaweed in inlet screens, which caused a loss of circulating water pumps, which caused a trip. (U2)

Circulating water pumps suck in whatever is out in the environment. By going to a cooling tower, chemistry can be controlled better. (C4)

3.1.11.2 Future heat sinks in the US

Rivers and lakes are out as far as heat sinks for future plants because of EPA regulations. In the US, future plants will be limited to cooling towers, with which it is easier to control chemistry; therefore, chemistry and biological factors shouldn't be as much of a problem as for seawater sites. (V3)

3.1.12 Service water system (BWRs only)

The service water system in a BWR provides cooling water from the environment to the closed cooling water system, which in turn provides cooling water to the condenser. The service water system is the interface with ultimate heat sink.

One of the problems, like the circulating water system in PWRs, is that it pumps in whatever is out in the river, ocean, or whatever the ultimate heat sink is. The solution to the chemistry problem is a cooling tower. (C4)

3.1.12.1 Service water system maintenance

In some plants it may be OK to reduce power to 50% to where only one train is needed, and then to do maintenance on the other train. (U8)

A BWR has a lot of systems with less redundancy than modern plants have. The service water system was very poorly designed. The staff can not work on anything in this system at power, and it's extremely difficult to work on it while the plant is offline. (U2)

It is better to maintain the emergency service water system at power, because it is needed when the plant comes down. (U24)

3.1.13 Reactor pressure vessels

3.1.13.1 Reactor vessel fluence

Reactor vessel embrittlement has become an issue for some plants. Embrittlement due to high neutron fluence can be solved for future plants by better materials selection, better quality control, and better vessel shielding. This will not be a limiting factor for future reactors. It has been a problem for current plants. (C4) (U14)

Utility 4 is still on 12 month cycles because of pressure vessel fluence issues. They run a low leakage core to achieve planned plant life. Longer fuel cycles are more difficult to design for low leakage. (U14) (U15)

3.1.13.2 BWR reactor vessel internals

BWR internals may be a problem for future plants. Even if they're built out of new materials, they are still going to be required to be monitored periodically. Internals are required to be tested on a 10 year interval. (C4) (U9)

- Jet beams crack. (C4)
- Core shrouds crack. (C4)
- Use ultrasonic techniques to test the instrumentation tubes. (U13)

According to GE, depending on the scope of failures of the vessel internals, utilities may be faced with up to $600M per unit in repair costs. (U23)

Hydrogen chemistry can be used to keep crack growth rates within acceptable limits. But it costs in exposure to the workers. (U23)

3.1.13.2.1 Thermal gradients

Near the end of the fuel cycle, the core reactivity becomes depleted. In order to continue operating, the power level must be dropped or inlet feedwater temperature must be dropped to add reactivity. Dropping the inlet temperature for the reactor puts thermal stresses on the reactor pressure vessel and the nozzles. (U5)

3.1.13.2.2 Nozzles and vessel penetrations

With aging, nozzles and vessel penetrations may exhibit cracking due to severe thermal stresses or poor water chemistry. As the plant ages, inspections are required to show that these components are still functional. Access to the control rod drive penetrations is very restrictive, and inspections will be difficult. (U5)

3.1.13.2.3 <u>Core shroud</u>
The core shroud is essentially a steel cylinder. It is susceptible to intergrannular stress corrosion cracking (IGSCC). BWRs are beginning to show signs of cracking in the core shroud. This is a significant safety issue. The concern is that in an accident, if the shroud was cracked and there was an upsurge of pressure, the shroud would lift up, move a little sideways, and prevent the control rods from being inserted. (U5) (U9)

BWR_#4 is going to be required to inspect their shroud for cracks in the next outage. They have assumed that they will have cracking, and are planning to implement a fix. Inspecting the shroud involves exotic inspection tools and significant time. BWR_#4 decided to just implement the fix, and assume that the cracking is there. (U5) (U9)

The fix that BWR_#4 is using is essentially a clamp between the upper shroud and the lower shroud. There are rods connecting the upper and lower shroud, and they are put in tension. This will hold the shroud together and eliminate concerns of a circumferential failure. (U9)

3.1.13.2.4 <u>Vessel welds</u>
BWRs are required to perform a full inspection of all the reactor vessel welds every 10 years. The law was changed from partial to full inspections. When BWR_#4's vessel was built, the welds were X-rayed. There were signs of flaws, which was normal. But they couldn't measure the size. There are now methods of determining the size of weld flaws, and plants are required to measure them, and will probably be required to measure them again in two years to see if the cracks have grown. This is a critical path item, because the reactor has to be empty of fuel for 10 days to inspect the penetrations. It adds 10 days to the outage. (U5)

3.1.14 Electrical system

3.1.14.1 DC breakers
BWR_#4 has two trains of DC power, and both are required for operation. It's very difficult to take any of the DC breakers offline. When a DC breaker is taken out, a whole distribution panel is taken out with it, because the testing can not be done live. So BWR_#4 has to use temporary modifications to provide DC power to critical equipment just to be able to take the breakers out for testing. During the next outage, these breakers will be tested for the first time since the plant was built (20 years). If they are in good condition, this may be evidence that the DC breakers don't need to be tested frequently. (U3)

3.2. Regulatory / institutional framework

The institutional environment is a generic class of concerns encompassing interactions with such bodies as the Nuclear Regulatory Commission (NRC), the American Society of Mechanical Engineers (ASME), the Vendors, EPRI, and INPO. However, the main constituent of this category is the NRC. The following is an outline listing observations and opinions regarding the interactions of the various institutional organizations with plant design and operations.

3.2.1 The Nuclear Regulatory Commission

3.2.1.1 Regulatory requirements

3.2.1.1.1 Over regulation
The staff of a PWR has become too concerned about regulatory requirements. The staff does not think in terms of reliability, it only thinks in terms of satisfying regulations. The industry has been driven rather than led by regulatory requirements. (U11)

About 50% of the regulatory requirements don't produce any value in safety or economics. After a certain point, additional regulations begin to adversely affect safety. Initially, adding good regulations increases safety, but after a point, adding additional regulations begin to overwhelm the utility, and safety begins to be compromised. Thus, there is a hump shape to the safety vs. regulatory curve. NRC has gone over the hump (too much regulation) on Appendix K requirements. They have made equipment inaccessible to the point where safety and economics are lost. (U14)

PWR_#5 was forced by NRC to spend a couple million dollars last year on a leak detection system that the PRA found insignificant. Hopefully, the maintenance rule will limit inappropriate items like this. (U13)

All BWRs with Mark I and II containments had to install a hardened wetwell vent for a specific severe accident. The cost was several million dollars, and it was just to satisfy a certain Generic Letter. The probability of that accident was about 10^{-8} per reactor year. Hopefully, in the future, things like the maintenance rule will alleviate these problems. (U10)

NRC became too prescriptive in the post TMI era. Within the past three years, NRC has been turning that around. It is difficult for NRC inspectors and people at the plants to look past the old prescriptive environment into one in which they have to begin thinking for themselves again. NRC is becoming more helpful and less paternal.(U9)

3.2.1.1.2 Rationalizing design requirements
The first and most important step to designing better plants is to rationalize the design requirements. The industry needs to go back to fundamentals, and question all of the requirements. Then the plants will have more time for response during accidents, and they

can design more rational and reliable systems. For example, the requirement on fast acting containment isolation valves and fast start diesel generators are too restrictive and may actually be contrary to safety because fast acting machines tend to be less reliable. The reason behind the fast start requirements on diesel generators is the Appendix K assumptions of a large break LOCA coincident with a loss of offsite power (LOOP), and the conservative assumption that all of the equipment needs to be online instantly. But designing for this short of a time scale puts enormous stresses on machinery, can reduce reliability and safety, and may have no physical justification. (U12)

3.2.1.1.3 <u>Surveillance requirements</u>

BWR_#4 spends an inordinate amount of time on load shedding tests. In the event of a coincident LOCA and LOOP, the plant has to shed a lot of its electrical loads, and then sequence certain ones back on after the EDGs start up. It is required to test that the load shedding works properly every outage. Its interpretation of "works properly" has been almost a full logic system functional test for every circuit in that load shedding. It takes 36 hours, and it is one critical path. For this case, the staff at BWR_#4 knows that they were doing more than was required, and they are going back and rewriting the procedure. (U23)

At BWR_#4, there is a class of tests that overlap. The logic system functional tests and the simulated automatic actuation tests both test much of the same logic circuitry. They were doing most of the testing twice. They are going back and revising these requirements. (U23)

3.2.1.1.3.1 *Self imposed surveillance requirements*

Plants have not sufficiently evaluated the effects of generic policy changes based on LOCA failures. When a particular relay fails, and is tested on a five year basis, the corrective action might be to test it on a two year basis. However, it might be decided to test *all* relays of that type on a two year basis. The impact of this is usually not appreciated. Now, all relays of that type are tested on a two year basis. But if none of them fail the test on a two year basis, the basis stays at two years, instead of being extended back to five years. This is very common in the industry. After sufficient time, these requirements build up and become overwhelming. (U23)

3.2.1.1.3.2 *Surveillance and maintenance extensions*

(See Section 3.6.1)

3.2.1.1.4 <u>Online maintenance</u>

If the utilities get into arguments with NRC over whether it is safe to do maintenance online, the public will never trust them. NRC is concerned about how plants can optimize their refueling outage durations, and at the same time not raise concerns over working on standby safety systems at power. Many stations are adopting an online maintenance strategy - they are taking safety systems out to do maintenance - but the position at NRC is that they do not want the utilities to be doing online maintenance of safety systems solely to reduce refueling outage duration. This can be overcome in a couple of ways. (1) ALWR approach - eliminate active systems, and (2) European approach - have many redundant systems. (P3) (N2)

NRC's view on operational maintenance is changing. It was previously very negative, but NRC is beginning to ask "when do plants really need this component to work?" If the answer is at shutdown, then plants should do the maintenance online. (P2)

3.2.1.1.5 Innovative techniques

NRC's attitude will evolve into letting plants use innovative techniques. The industry is at the stage where it can learn how to use advanced technologies by risking relay, circuit, or valve failures without jeopardizing public safety. The incentive is reliable operation of the plant. However, plants have to differentiate between failure modes in which there is and is not a significant safety risk. Plants can not afford a pump seal LOCA, or a problem with the primary pressure boundary, the containment, or the fuel.(P2)

The regulatory climate is good for new technology. There is a new receptiveness to looking at things from a risk perspective (in the last 2 years). NRC is beginning to use risk concepts to make rational decisions, but not as the sole basis for decisions. (N5) (V1)

3.2.1.1.6 Containment leak rate tests

There are containment leak rate tests (Appendix J) that need to be done every 24 months. Regulations are much more difficult to change than Technical Specifications. (U20)

3.2.1.1.7 Regulatory emphasis

In the design stages, NRC should be consulted to see what their explicit concerns are (i.e. LCO maintenance) and then designers can understand and address these concerns. (U8)

From a regulatory point of view, it is clearly the surveillance of safety systems, steam generator tube inspections, and containment leak rate tests that are important. NRC is going to be very restrictive with respect to running steam generators for longer cycles without inspections, even with new tube materials. (N2) (C4)

Generic Issue 23: NRC is trying to make the plants have an independent method of seal cooling that can be lined up within 10 minutes following loss of seal cooling. (U13)

3.2.1.1.8 Diversity requirements

There has been regulatory insistence on diverse equipment drivers (i.e. electrical powered motors, steam driven turbine motors, diesel powered motors) in key systems such as auxiliary feedwater. But experience shows that this has not improved safety. (U12)

3.2.1.1.9 Separation requirements

Equipment separation requirements are an enormous contributor to down time. It makes sense electrically because of the effects of fires or floods. But a fire or flood won't affect a pipe. Reduction of the separation requirements will make maintenance significantly easier.(U12)

Plants barricade equipment to meet the requirements for flood, fire, and separation, but this increases the reliance on external cooling and support systems. (U13)

3.2.1.2 NRC assistance

3.2.1.2.1 Surveillance extensions
See Section 3.6.1.1

3.2.1.2.2 Inspection and surveillance criteria
A review of current inspection and surveillance criteria would supplement the information and insights that would be gained by a focused examination of equipment failure data. (N1)

3.2.1.2.3 Modular I&C specifications
Design assistance criteria are used in the instrumentation and control (I&C) area. Basically, the plant is designed for certification without the detailed I&C design. This allows customers to specify the design with state of the art I&C so that it does not become obsolete. (N3)

3.2.1.2.4 Cost beneficial licensing actions (CBLAs)
The Cost Beneficial Licensing Action program is new at NRC. Historically, if plants had a cost saving proposal, NRC was reluctant to provide the resources to evaluate the proposal. But now NRC will let operators fill out a form, and the NRC gives it to a special reviewer who comes back in a prioritized fashion. If the plant satisfies the safety concerns, NRC gives the plant a fast track to approval. (C6)

3.2.1.2.5 Analysis of operating data
AEOD deals with trends and patterns. The trending guys spend 6 to 12 months on a particular system. They are looking at systems microscopically. There are procedures to get access to this data. (N6)

3.2.1.3 Quality assurance (QA)

3.2.1.3.1 Historical quality assurance programs
One of the biggest wastes of money is maintaining the level of QA on systems that are not risk significant. Spare parts for insignificant systems have to be QA approved, and that's expensive and difficult. Quality Assurance does little for reliability, but it has to be there to satisfy regulations. (C2) (U11) (U13)

3.2.1.3.2 Graded quality assurance
BWR_#2 expects to save millions by buying less safety related equipment under the graded QA program. Graded QA gives the utilities a less prescriptive approach to QA. It

allows them to focus more on the important equipment and less on unimportant equipment. (U10) (N6)

3.2.1.3.3 Making equipment QA

There is a big problem finding "Q" equipment. NRC has forced some of the vendors out of the market because they were being held liable for shoddy equipment. NRC is now trying to establish how utilities can take non-safety grade equipment, and put it through its own tests and standards, and then put it in a safety related system. The ability to take a low cost component, test it, and then be able to use it in a safety system will save the industry a lot of money. (U9)

3.2.1.4 Maintenance rule

3.2.1.4.1 Rationalizing maintenance

The maintenance rule is designed to focus maintenance resources in the most risk significant areas. If it is successful, plants can eliminate all the prescriptive regulations that have wasted time and resources. The maintenance rule is performance based regulation. It has changed the philosophical outlook of the industry, because it focuses attention on what is important. (U14) (U13) (U9)

The maintenance rule is mostly based on trending. If a component is safety related, then performance goals are set for it. If the plant meets the performance goals, they can start doing less maintenance, and they get more freedom. If the plant isn't meeting the performance goals, it has to re-evaluate its program.

3.2.1.4.2 Capacity factor through the maintenance rule

Plants have not started looking at PRA for plant capacity yet because the PRA program was started based on safety. But the philosophy is changing because of the maintenance rule. The maintenance rule addresses non-safety related system reliability by considering unplanned trips as safety threats. Consequently, it looks at the secondary system and what is causing these trips. (U20)

3.2.1.4.3 Defining safety significance

Without drawing a line (say 10^{-6} core melts per year), everything is needed. But once the level of safety significance is defined, plants can decide whether something is really "needed" on a rational basis. (U10)

3.2.1.4.4 Reliability centered maintenance

Reliability Centered Maintenance (RCM) does an analysis to develop cut-sets for critical equipment. Any new plant should adopt this method. It identifies design weaknesses, and concentrates maintenance where it is needed. It is closely related to the maintenance rule. (U24)

3.2.1.5 Technical Specifications

Technical Specifications specify the allowable plant configurations and states. They specify what components and systems are allowed to be inoperable as a function of time and configuration. (C4)

It may be advantageous to examine the Technical Specifications of a newer plant to find out what surveillance tests have to be done, and how to get rid of them. To go to longer cycles, plants have to do a lot of online testing. (N2)

3.2.1.5.1 NUREG 1377

NUREG 1377 was an effort by NRC to solicit industry comments and to rationalize Technical Specifications. For the first time, NRC decided what should and should not be in the Technical Specifications. NUREG 1377 addressed reduced testing, aging, degradation mechanisms and techniques for monitoring, inspection, testing, and surveillance. (N4) (N1) (N6) (U9)

3.2.1.5.2 Standard Technical Specifications

Standard Technical Specifications (STS) were developed by NRC with assistance from the vendors to eliminate many outdated requirements. Crystal River adopted STS and made back the investment in their first outage. There is also a line item improvements program. But neither are being utilized yet by industry. About 40% of LCOs and surveillance requirements can be eliminated by revisiting Technical Specifications and revisiting licensing bases. (N6)

The BWR owners group worked together with NRC to develop their own standard technical specifications. They did a very good job. There are now a new set of standards. NRC will allow utilities to compare their technical specifications to the STS and adopt the sections they like, as long as the utility can show that its equipment can support it. They can not pick out very specific pieces, but they can adopt sections. It gives the utilities the chance to revisit their technical specifications and remove the unnecessary, over burdensome requirements. BWR_#4 divided the STS into two sections: operations maneuverability and outage enhancement. (U9)

3.2.1.5.2.1 *Operations maneuverability*
This includes technical specification revisions that will translate into fewer plant perturbations. BWR_#4 has eliminated many reactor trip setpoints as a result of changes in the technical specifications. (U9)

3.2.1.5.2.2 *Outage enhancement*
BWR_#4 is about to revise their technical specifications to improve their outage flexibility. It is tough to analyze outage technical specification changes because it is not clear what

the benefit will be. Regardless, BWR_#4 is trying to identify those things that can reduce outage scope. (U9)

3.2.1.5.3 Limiting conditions for operation (LCO) maintenance

The Technical Specifications dictate the allowed configurations for plant operation. When a component or system becomes inoperable, the plant typically has to shut down immediately (if the threat is serious), or the Technical Specifications give an allowed time to make the component or system operable before the plant has to go to lower modes of operation. A plant in this state is said to be in a "limiting condition for operation."

3.2.1.5.3.1 *LCO extensions*

Utilities can ask NRC for relief for one time extensions if they have or anticipate having an allowed outage time violation (see next section). The plants can make risk arguments on the time window and averaging the risk over the 40 year life of a plant. But arguments like these—if made too frequently—begin to degrade safety past what was intended by technical specifications. (U9)

3.2.1.5.3.2 *Allowed outage time violations*

Occasionally, plants run into a Technical Specification allowed outage time violation. For example, if the operators test a safety system online, and it does not work, then the plant has a specified time interval to get it running. Otherwise the plant has to go to progressively lower modes of operation. One resolution to allowed outage time violations is extending the allowed outage time using PRA. (V2)

3.2.1.5.3.3 *Voluntary LCO maintenance*

If plants need to be able to take a system out of service for a finite period of time for inspection, calibration, maintenance and/or repair, they may have to enter an LCO to do this. Deliberate entrance into LCO is a current practice, but NRC does not like voluntary LCO entrance because it degrades the overall safety over that time period. (U8)

In five years, voluntary LCO entrance will probably not be a big issue. NRC will become more receptive. (U12)

If the technical specification allowed outage times can be extended long enough, maintenance can be done online without added redundancy. (V2)

NRC did not make evolutionary designers go to installed spare designs for safety systems. If plants do the economic calculations, and amortize that cost over 30-50 years, redundancy will probably pay for itself because of increased capacity factor. The staff would prefer that option. The staff probably will not like the idea of LCO maintenance. (N2)

BWR_#4 approaches voluntary LCO conservatively. The requirements are that the maintenance can be completed in less than half of the allowed outage time. The procedure must be reversible so that if it becomes apparent that the repair or maintenance cannot be completed, they can back out of the maintenance. Extensive planning is required. (U23)

3.2.1.5.3.4 *Risk basis for LCO maintenance*

Voluntary entrance of LCOs should be approached on an instantaneous risk basis. There are tools that will allow operators to input the specific plant state, and that will give them the instantaneous risk level of the plant. This tells them if it is acceptable to take certain equipment combinations out of service for a given period of time. Utility 1 uses this technique. (U12)

INPO has some concerns about voluntary LCO maintenance in addition to NRCs concerns. A few years ago, INPO was advocating doing more maintenance online, but found that in some instances, the risk increase was unacceptable. An online PRA allows plants to do more LCO analysis. It gives plants a full understanding of what risk status the plant is entering by taking things out of service. PWR_#8 is using an online PRA for real-time decisions. (N5)

BWR_#4 used their PRA to justify some of its LCO time limits. They also used their PRA to set up system and component level outage time goals. They also have an overall plant level risk increase goal so that doing a lot of minor LCO maintenance does not exceed the total plant risk level goal. However, BWR_#4 does not yet use an online PRA for day to day operations. (U23)

3.2.1.5.3.5 *LCO maintenance and safety*

The claim that "it's safer to do some maintenance at power" is just a rationalization to be able to do maintenance at power. Future designs should be configured so that it is safe to do maintenance while shutdown. That way, plants can not use this as an excuse to do maintenance at power. At power, there is less time to react. In shutdown, there may not be as many safety systems available, but there is a lot more time to respond to accident conditions. (N2)

LCO maintenance is valuable and safe if all the factors are truly taken into account. But operating experience says that plants really have to be careful, because that's when bad things happen. A technician lifting the wrong lead or pushing the wrong button can initiate a transient that shuts the plant down and/or challenges the safety systems. (P2)

3.2.1.5.3.6 *Voluntary vs. unanticipated LCO maintenance*

The difference between voluntary entrance into LCOs and forced entrance into LCOs is that forced entrance is less frequent and is the basis for the PRA. When plants start entering LCOs voluntarily, they destroy the statistics that were used to justify LCO maintenance. Therefore, plants have to be able to show that the overall risks are not increased significantly or are decreased by going to LCOs for maintenance.(U8)

The concept of LCO maintenance was never intended to be used frequently, because this involves deliberately cutting into redundancy that people assumed was there when making safety judgments and in their PRA analyses. Therefore, there will be resistance to incorporating this option into the design and technical specifications. (N2)

3.2.1.5.3.7 *Operating risks*

Whether LCO maintenance is a safety concern or not, it is an economic concern. The problem with LCO maintenance is that the biggest source of unanticipated scrams is technician error. Systems have to be designed so that technician error is unlikely to cause problems in other systems. Plants have to be able to show that online maintenance will not affect plant operation. (P2)(V4)

3.2.2 ASME equipment testing codes

To go to longer maintenance and testing intervals, the ASME codes must be consulted. ASME is currently revising the maintenance and inspection codes. (N1)

3.2.3 Vendor recommendations

There has been a mind-set in the nuclear industry to follow vendor recommendations without a questioning attitude. The question is what the risks are of extending the periodicities of inspections and maintenance. In a lot of cases, the equipment is already designed for 2 years, and at least longer than the vendor recommendations. What is uncertain is by how far. (U21)

3.2.3 Utility Requirements Document

The Utility Requirements Document is a document that was put together by the utilities outlining what they thought were the requirements for ordering new nuclear power plants. (V1) (P4) (N5) (P2)

The following is a list of the Utility Requirements Document points that were considered significant by the interviewees:

1. Focus on a safer plant that has learned the lessons of previous plants. (V1, P4)
2. Better containment (P4)
3. Lower overall costs. (V1) (P2)
4. Lower O&M costs from less maintenance and higher capacity factor. (V1)
5. Shorter constructions times due to better construction techniques. (V1)
6. More maintainable. (V1)
7. Improved online maintenance and testing. (P2)
8. Higher capacity factor (87%). (V1) (P2)
9. Lower forced outage rate (P2)
10. Lower planned outage times. (P2)
11. Capable of a two year cycle. (V1)
12. More thermal margins in systems. It's OK to lose a little thermal performance to make the systems more reliable, and to give operators more room to stay within Technical Specifications. (P4)
14. Simplification of the plant and safety systems. (P4)
15. Incorporate digital technology. (P4)

3.3 Probabilistic techniques

Probabilistic risk analysis (PRA) and spin-offs such as availability analyses became popular only after the current generation of power plants were completed or under construction. PRA has generated many insights into reactor design that were not available to the first generation designers. Therefore, it is not surprising that there are many who think that PRA should be used as a design tool. The following is an outline of the comments made in this regard.

3.3.1 Computer-based PRAs

There are computer codes that allow the plant PSA to be loaded into them to examine the affect of system degradation on risk, but there are not any comparable codes for analyzing availability and capacity factor. (C2)

Computer-based PRAs can be offered as an operational tool to the shift engineer's office, the maintenance planner's office, or the operating engineer's office. (Probably not the control room because they are already overburdened.) It can be made available to the people making decisions on when, how and whether to enter an LCO. (U12)

Utility 2 has their PRAs on computer. They are going to an automated system where the outage schedule will be linked to the PRA to determine the risks as a function of time. (U13)

A code developed by NRC exists that is part of the RCM program for predicting reliability. (C6)

3.3.2 PRA in design

3.3.2.1 Importance measures

Designers should distribute the importance more evenly among all components. That way no single component can greatly affect reliability or safety. One goal should be the optimization of the maintenance burden with respect to availability. For example, if there are two components, one very important to system availability and one not very important at all, more time should be spent maintaining the important component and less on the unimportant one. (C7)

One major problem with current designs is that the front-line systems are typically very reliable, but the support systems have little redundancy and are very important. This is where adding small, cheap redundant components can buy a lot in terms of availability. (C7)

One way to make components less significant to plant safety, operability and reliability is through redundancy and diversity. Another way to make active components less risk significant is to use passive and semi-passive systems for safety functions (e.g. the AP600). (C7) (N1)

3.3.2.2 PRA early in design phase for decision making

Incorporating PRA into the design phase will allow for more rational design of systems. It can be used to make design decisions. The effects of system modifications can be immediately explored at low costs using PRA.(C2) (U11) (N5)

Using PRA, Utility 1 has found that subtle differences can drive CDFs a factor of ten higher. For example, a small difference in the arrangement of the electrical power buses made BWR_#6 CDF a factor of ten better than BWR_#1's. Incorporating PRA into the design phase would prevent poor design decisions such as this from affecting safety. (U12)

PRA can be used to make choices in equipment purchases. PRA can be used to determine the likelihood of a component lasting for 3,4,5 years. (C2)

3.3.2.3 Inspection intervals

There is an availability code called SOCRATES that is used to do plant reliability and availability analyses. It determines the effects of extending the surveillance interval on reliability by using fault tree analysis and reliability predictions based on past equipment history. It will show on a graph if going from 30 to 120 days between tests actually improves reliability. (C6)

PRA is also very useful for the determination of the optimal inspection intervals as a function of plant and component age. (A3) has done work on aging and its affects on PRA. (N1)

3.3.2.4 Licensing

Any new plant will have to have a PRA to be licensed. A PRA (even top level) should be performed on an extended cycle design if it is to hold credibility in the industry today. It provides clues and answers that might not otherwise be thought of. If a PRA is beyond the scope of this research, it should be mentioned in the write-up that one should be performed as part of any formal effort to build a plant like this. (U12)

3.3.3 Availability analysis

(U13) used to be involved in an engineering group that came up with suggestions for improvements in availability. The group looked at all the lost generating events, and tried to trend some of the causes. There didn't seem to be much commonality for a lot of the things the group trended. The group found many problems, but less solutions: turbine blading, steam generator chemistry, valves, etc. The group didn't come up with many things that the engineers didn't know, so the group was defunct in 1988. There needs to be strong management who will push the ideas for a group of this type to be effective. (U13)

A traditional probabilistic risk analysis has typical end states such as minor core melt, major core melt, major offsite release of radiation. The end states (i.e. the plant condition after a state transition) of a plant power availability analysis, however, become percent plant power after a failure or modes of operation at different plant configurations. (C2) (U11)

3.3.4 Common mode failures

The common mode failure fears have been turned in the wrong direction. It's an academic exercise with a couple real world examples. The fact is, to prevent plants from doing things that they know are safer because of concerns, which may or may be not be out there, is wrong. The industry is trading real world problems for fear of a common mode failure. The industry needs to become more mature on this issue. The common mode may be out there, but the fact that it would manifest itself at the exact same time adds a whole other element that usually is not taken into account. For example, the ATWS situation requires two different shutdown mechanism from two different manufacturers. But it is known that most of the problems with reliability are maintenance related. Now technicians have just been exposed to two separate systems from two different manufacturers. This is guaranteed to cause problems. (P2)

3.3.5 PRA for safety maintenance and LCO justification

(See section 3.2.1.5)

3.4 Design principles

The fourth broad category identified was comments concerning general design principles that should be followed. This category includes perceived advantages and disadvantages of diverse design philosophies. This category delineates underlying principles that should be understood and considered by the designer and operator.

3.4.1 Fundamentals

3.4.1.1 Design margins

The industry let the wrong pressures drive it initially. In the search for better heat rates and efficiency, engineers squeezed the fundamental design margins out of the plant. They made the heat exchanger tubes thinner, the cladding thinner, they made the diameters smaller. In doing so, they made them much more susceptible to failures. It would be beneficial to put some of the design margins back into the steam generators, the condenser, and the fuel. (U12)

3.4.1.2 Complexity

System complexity is a problem. Should reduce the number of active systems. (U16)

3.4.1.3 Advanced technology

In thinking of future plants, don't be caught up in using proven technology. Use advanced technology in the design, because it will be proven by the time this type of reactor is built. There are big paybacks using advanced technology. (P2)

3.4.1.4 Maintainability

It is good to design maintainability into the plant - it's a big problem in US plants today, as opposed to the Swedish and German plants that were well thought out in terms of trains and equipment setup. (P3)

3.4.1.5 Systems to focus on

Focus on (1) the heat removal network for the standby equipment, (2) the feedwater system, (3) the turbine generator, and (4) auxiliary systems. (V3).

3.4.2 Redundancy

3.4.2.1 Online maintenance

Higher redundancy can be used to facilitate online maintenance. Installed spares allow components to be taken out of service for long enough to perform maintenance carefully without jeopardizing safety or availability. (C4) (N1)

ABWR - the ABWR has a 3 division ECCS. It can afford to take a division down and do surveillance and maintenance while at power. The following was the design philosophy:

- N+1 redundancy for ECCS because the extra train can be maintained online under LCOs or in shutdown without affecting safety.
- N+2 redundancy for heat removal function because heat removal is required continuously, and can not be degraded online. (V3)

Swedish plants - some plants in Sweden have installed spare trains. Forsmark has 18 day outages on an annual cycle. They can do this because they are able to do online maintenance and online testing. They have essentially met the objective of performing many critical activities online, but on a shorter cycle length. (U8)

German plants - the German philosophy of 4 trains was not for safety, but for online maintenance. That was felt by the US industry to be too expensive. US plants can not just add extra trains of equipment just to do online maintenance. It may be OK if the plant was completely redesigned, but not with current designs. (P2)

European plants - the European approach to online maintenance is to have many more safety trains available. If there are four 100% capacity safety trains of HPCI available, there are fewer ramifications from taking one out for online service. (P3)

Redundancy provides flexibility to bypass equipment to permit maintenance at power. Using extra trains and/or cross ties can improve availability. Muhleberg, a plant in Switzerland, has two 50% turbines.(C5)

Continuously operating equipment needs to be designed with enough redundancy to be able to take it out of service, inspect it, test it, and put it back in service. (U20)

3.4.2.2 Cost considerations
To justify redundancy, the benefits must exceed the costs incurred by a significant margin. The German philosophy of installed spares was considered by the US industry to be too expensive. All costs of redundancy must be justified from an operational perspective. However, if a plant is completely redesigned with the idea of performing all maintenance online, redundancy may be more cost effective. (V2) (P2) (N5)

3.4.2.3 Where redundancy may not work
With pumps and valves, redundancy is only a question of money. The components that will become problems are the large, expensive components where redundancy is not cost justifiable - steam generators, turbine-generators, main coolant pumps, and those things can not be maintained online. (C2) (U11)(C4)

3.4.2.4 Effects of insufficient redundancy
The problem with existing plants (especially older ones) is they were built with the minimum amount of redundancies required for safety. There wasn't much thought given to adding redundancies to improve operations. Some of the newer plants have incorporated redundancies for some components critical to operation. (U24)

BWR_#4 was designed with the minimum required redundancy. There are two trains of ECCS. In some instances the trains can be traced back to the same sources. As a result of the limited redundancy, outages and maintenance are extremely difficult to configure, and are restricted. (U23)

If BWR_#4 had been designed with three trains of ECCS, it would have paid for itself. BWR_#4 recently had a problem repairing the coolant injection system. They had a 7 day LCO window, but had to get a 7 day extension to complete work. If the plant was designed with three redundant trains, there would have been no rush or safety degradation. All the breaker PMs, the battery testing, the diesel generator overhauls, and the transformer tests could be done online if there was an additional train of ECCS available. (U3)

3.4.2.5 Unnecessary redundancy
There are not that many places where redundancies really need to be added, if the plant starts out with a clean slate and is designed for expeditious service of systems. Things like not having to lift leads to do maintenance should be incorporated into the design. Then safety and risk arguments can be made well without adding redundancies. (P2)

3.4.2.6 Complexity
It is good to have redundancies, but only when they are really necessary. Otherwise, it is just adding to complexity. Not much redundancy is needed for standby systems. It just has to be shown that it's OK to maintain them from a risk perspective. (U20) (U16) (V2)

3.4.2.7 Dependencies

Redundancy can lead to dependencies. Components performing several different tasks (e.g. a pump that acts as both HPI and CVCS) can lead to complexities and dependencies. There are some plants that have RHR systems that are also used for safety injection. There was a Technical Specification that said if there is a problem with the safety injection, the plant has to shut down. But now the plant is shutting down with no way to cool the core. (P2)(N1)

If maintenance is going to be performed online, make sure that the systems are isolated from each other so that maintenance on one system does not affect the operation of another system. (V4)

3.4.3 Accessibility

3.4.3.1 Inspection

Particular design consideration must be given to components inaccessible to normal inspection (i.e. BWR internals). Modern instrumentation with its self checking capability helps. The key is developing non-destructive techniques for monitoring component conditions, but it is difficult to develop such methods to work at operating temperature and pressure. (C5)

Accessibility for inspections should be provided by design. All welds should be inspectable. This will reduce the down time for required inspections. (N5)

3.4.3.2 Maintenance

Plants should be designed with maintenance in mind. Component accessibility is important. Maintenance workers have to be able to get to equipment that needs to be maintained. In some cases this just can not be done. (V2)(U14) (U16) (U24)

3.4.4 Diversity

Diversity has proven to be fallacious on its impacts on safety and an enormous maintenance burden. For example, auxiliary feedwater (see also Section 3.1.1.3). There is a requirement to have a turbine or diesel driven pump in addition to motor driven pumps. That requires an enormous maintenance burden because turbine and diesel drives are far more complicated than a motor drive, and far less reliable overall. Plants are better off with two or three motor driven pumps, than with two motor driven pumps and one diesel or turbine driven pump, in terms of system reliability and safety, and in terms of maintenance load. One of the bases for diversity in auxiliary feedwater was station blackout. But NRC has subsequently said just put in an additional diesel or a gas turbine to cover station blackout. The alternate diesel or gas turbine does not even have to be fast start or safety related; consequently, they will be much more reliable machines. (U12)

Starting with a clean sheet of paper, use diesel systems that are more reliable and that will function better to backup normal AC power, and eliminate unnecessary diverse component drivers (motive force) for safety related components. (U12)

3.4.5 Architecture

Westinghouse, ABB-CE and GE have come up with new reactor designs, but there has been minimal collaboration with architectural engineering companies like Stone and Webster or Bechtel that actually design the layout. The NSSS vendors come up with tremendously reliable systems, but the architectural company will put in systems that are at the discretion of the site. Therefore, there are some risk and operationally significant items - like the HVAC system -that are designed by the architect. Those systems are necessary and very risk significant, but are designed by the architectural engineers. In general, the architectural engineering firm designs the balance of plant. (U13)

3.4.6 Shutdown Safety

Shutdown safety should be considered in the original design of the plant. (N1) (N2)

3.4.7 Vulnerabilities to auxiliaries

Auxiliaries are those systems needed to keep the front-line equipment working. They include electricity, air, cooling water, lube oil, and seals. Auxiliaries are typically less reliable than the front-line systems, and limit those systems' reliability. (C4)

3.5 Economic pressures

The next category is economic pressures. The main motivation for any redesign or modification of current plants is cost competitiveness. Economic pressures are currently driving the industry, and they should not be forgotten in design or operation.

3.5.1 General comments

Keep all non-safety decisions based on economics. If another train is proposed, ask how much it is going to cost, and how much will it save. If it does not save money, don't do it. (U24)

3.5.1.1 Electricity costs

PWR_#7 1 and 2's production rate is $14/MWh-e. Their bus-bar cost is $25-$28/MWh-e. Many plants are 4-5 times this much. Those plants aren't economical. Independent power producers (IPPs) can install a new plant and produce power at about $30-$35/MWh-e total cost. Unless other nuclear plants can beat this, they shouldn't be in business. Targets for new plants have to be under $40/MWh-e. (U14)

PWR_#10 is targeting going from $45/MWh-e to $30/MWh-e. BWR_#5 is targeting going from $75/MWh-e to $45/MWh-e. (U15)

3.5.1.2 Regional effects

The viability of nuclear power and the value of energy varies from region to region. In the midwest, power is cheap. But in the northeast (like New York), power is very expensive, and a lot more can be done to improve the economics. The cost of electricity can vary by a factor of 10 by region. (U14)

3.5.1.3 Breakdown of costs

Capital costs are about 50%, O&M costs are about 25%, and fuel costs are about 25%. So 75% of the busbar costs are inversely proportional to capacity factor. (fuel costs are the same whether you run well or not). (U18)

Cycle costs: normal O&M is ~ \$120M / yr.
outage costs are ~ \$30 M above normal O&M
Fuel reload (18 mo.) ~ \$30-50 M

For an 18 month cycle, it costs roughly \$200 M. (U18)

3.5.1.4 Power pools

Power pools would like longer cycles. They get more flexibility that way. It would be worth it to them to let nuclear plants go offline for a little while for mid-cycle maintenance, as long as there is flexibility and the outage is short. (U18)

3.5.1.5 Longer cycles

Some utilities didn't get savings by going to longer cycles. Utility 4 is achieving ~90% capacity factors on a 1 year cycle. A long cycle plant just can not do much better than that. So maybe a better thing to look at is shorter cycle lengths with very short outages and high operating reliability. (U14) (P2)

3.5.1.6 Plant size

A compact plant with a high power density and forced circulation is always more economically attractive. (V3)

3.5.2 Capital costs

3.5.2.1 Capital requirements

It is very difficult to sell a multi-billion dollar power plant to a board of directors. Current targets are \$2B. That would double most utilities balance sheets. Plus the risk is high. So increased capital requirements are looked upon very negatively. Adding redundancy may look good on paper, but the capital outlay may be too huge. Economics says stay away from capital and labor intensive ventures with high risk. Nuclear power has all three. (U14)

3.5.2.2 Steam generators

The additional capital price for better steam generators will pay for itself. (P4)

3.5.3 Capacity Factor

3.5.3.1 Diminishing returns of longer cycles

There are diminishing returns to capacity factor as a function of fuel cycle length. Under the same assumptions, if you're getting 76.5% capacity at 18 months, you can get 81.7% at 24 months, and 88.5% at 5 years. It does not make sense to go past 5 years, because the return is very small and the difficulties are too great. (U18)

3.5.3.2 Known costs vs. perceived gains

The utilities will not look favorably on trading a known cost for a promise of a gain. Strong evidence of the return on investment is necessary. Typical utilities discount claims of higher capacity factors. One has to win with a 3 to 1 or a 4 to 1 ratio (i.e. it takes 3-4 soft dollars to equal one hard dollar). To justify a modification, the value of a percent increase in capacity factor must be calculated, and only 1/3 or 1/4 of that value should be spent to achieve an expected gain of that percent of capacity factor. (V3) (P2)

BWR_#4 uses a three year payback horizon. If equipment modifications aren't expected to pay for themselves in two cycles, then they can not be justified to the accounting department. (U3)

3.5.4 Labor requirements

Online monitoring, inspection, calibration, maintenance and repair techniques can be used for labor reduction during outages instead of cycle extension. That will pay for itself. The real problem facing the industry today is reducing labor. PWR_#7 used to operate two plants (total 1000 MWe) with 100 people. Now they have 800 people, which is too large of a staff. A lot of this is security and meeting the regulatory QA/QC. Labor requirements have to be decreased with minimum increases in capital costs. (U14)

Reducing labor requirements can be achieved through re-engineering. Re-engineering asks "What are the inputs, what are the outputs, and what is the cheapest, most efficient way of going from inputs to outputs." (U15)

Plants tend to try to over control everything that goes on in operations and outages. These restrictions drive the labor requirements higher. Essentially, the industry, NRC and INPO have created the current over staffing requirements in the industry. Every regulation adds additional workers. Additional workers require additional QA people to check their work, additional security to monitor them, and additional administrative people to keep track of them. The industry has over-reacted to concerns and regulations, and they are paying for it. This is beginning to change. (U23)

3.6 Operations and maintenance practices

This section addresses operations and maintenance considerations for longer operating cycles. Designing to facilitate operations is an important facet that many people think was neglected in original designs.

3.6.1 Surveillance requirements

3.6.1.1 Surveillance interval extensions

NRC is concerned about nuclear safety unless there is verification of component operability from periodic surveillance tests. To go to longer cycles, plants have to be able to convince NRC that less frequent surveillances and/or overhauls are justifiable. This can be addressed using PRA analysis, or otherwise the plants have to convince the NRC that the online diagnostics are acceptable as proof that there are no system degradations. If plants can not do this, all incentives to going to longer cycles are lost. (U14) (U21) (U15)

There are a lot of inspection requirements that currently require plants to come down every 18 or 24 months. Some of those requirements have been extended, but others have not. Some of the inspections can be done at power. It may be beneficial to look at a newer plant and do the analysis. Maybe the plant could come down after 2 years to do some of the minimum surveillances, which may not significantly affect capacity factor. (V1)

Surveillance requirements are currently prescriptive. Plants can only get a total of 25% surveillance interval extension over 3 refueling cycles. Plants currently have to shut down because of instrumentation drift. But if digital instrumentation is used, plants can eliminate many of these problems. (N3)

Generic Letter 91-04 addresses surveillance requirements. Generic Letter 91-04 is a cookbook that tells each utility how to extend their refueling interval surveillances from 18 months nominal to 24 months nominal. There are four requirements:

a. Comparative review of surveillance testing. Are the tests really effective?
b. Corrective maintenance history. Have they run OK for current intervals?
c. Plant specific drift analysis. Look at the data for individual instruments.
d. If the drift is not bounded, do additional analyses. (C6)

Surveillance intervals are relatively easy to extend as long as there is good performance data to show that there haven't been problems with the equipment in the past. (U15)

The last criterion is that the margin of safety can't be reduced by checking them less frequently. It has to be proved that inspecting instrumentation more frequently than necessary has a more negative impact on safety than letting it sit for longer. Or it has to be proved that when it is tested, the calibrations never change. (C6)

EPRI put together a guideline that specifies how to do the analyses to extend surveillance intervals. EPRI did work on about 10 plants to verify the guidance. (C6)

BWR_#4 just extended their major surveillance intervals to allow a 24 month cycle. BWR_#4 was originally on a 12 month cycle. When they went to 18 months, it was mostly an administrative change. However, it was more difficult to justify going to 24 months. If the existing equipment did not show sufficient reliability, they bought new equipment that did. Going from 18 to 24 months removed some of the margins that previously existed in setpoint levels for water level, high flux, and high pressure scram points. (U9) (U23)

For BWR_#4, extending the surveillance requirements is the single biggest limitation to going to cycles longer than two years. (U1)

3.6.1.2 Decreased reliability due to over surveillance

Plants don't want to do surveillances on a weekly basis if it is going to break equipment, but they are required to anyway. There are many surveillances done that require pulling out drawers and plugging in leads. This is hazardous to the equipment. By doing excessive inspections, plant equipment is being worn out. So it is often better for reliability and durability to extend surveillances. (C6) (U10)

For example, when a drawer is pulled out to perform a surveillance, the coax cable gets extended and pulled back in. Sometimes it gets shut in the door, and then the plant has to buy a $10,000 cable. It happens all the time. So by extending surveillance intervals, a lot of money on wear and tear and on technician time can actually be saved, and it will not affect plant reliability or safety. (C6)

3.6.1.3 Staggered vs. sequential testing

Testing can be done staggered or sequentially. If testing is done sequentially, the equipment must be made error resistant. If the technicians check something and then check the next thing sequentially before making sure the previous one was back in service, a plant transient or trip may result. (C6)

3.6.1.4 Monitoring vs. physical surveillances

One method of surveillance is to go out, hook up a pump to a pressure transmitter, and take a reading. If it's within tolerance leave it alone, otherwise, fix it and then leave it alone. This is a real, physical test. (C6)

Another method of surveillance is to monitor readings online. A computer can be used to monitor the readings, and when one starts drifting from the others, something is wrong. (C6)

Instead of checking all the instrumentation at once during a refueling outage, plants want to be able to only check a half or quarter of the channels. Then at least one channel is known to be operational, and online monitoring can be used to verify the functionality of the rest. Weighted averages are used to determine when something is out of calibration with respect to the others. The computer will automatically alert the operator when there is a problem. (C6)

3.6.2 Preventive maintenance

It is a design problem when doing a routine PM, surveillance or instrument calibration requires energizing switchboards and lifting leads, including using jumpers. That is a situation that is guaranteed to produce problems. If it is the desire to do this at power, it ought to be designed in. A key lock that clearly facilitates surveillance by design is superior. If proper consideration were given to online PMs, surveillances or calibrations, then doing this online could be done with higher comfort. Most errors aren't safety problems, but are operational threats. Plants lose money and credibility if they trip too much. (P2)

BWR_#4 is just learning how to shift from a corrective maintenance strategy to a preventive maintenance strategy. They are moving towards online preventive / corrective maintenance. Operations is resisting. They're trying to reduce outage scope by doing more preventive maintenance online. The risk is that there will be more plant trips due to errors or reduced redundancy. (U9)

3.6.2.1 Extending PM periodicities

The O&M people want to shut down every 100 days to do preventive maintenance. Major preventive maintenance is done on things like MSIVs, feedwater isolation valves, and RCPs. Most of the industry is looking at extending the periodicities of these PMs to much greater than 18 months. Take for example the electrical safety trains. Until recently, PWR_#1 had been doing PMs on electrical safety related buses every 18 months, and thought it was improving reliability. They decided to go to 3 years. PWR_#11 has already done that. (U21)

Have to look at the maintenance history of individual components to justify going to longer operating periods. (U26)

3.6.3 Online testing

3.6.3.1 Effects of online testing on safety

Online testing of components may increase the core damage frequency (CDF) if the test is to be a "full functional test." For example, testing the depressurization system in the AP600 may cause a large break loss of coolant accident (LBLOCA). (N1)

For some systems, it is far safer to do testing at power. For others, it's currently impossible to do testing at power. (P2)

3.6.3.2 Effects of longer testing intervals

Increasing time between tests can lead to an unacceptably high failure rate if the failures are "time in standby" related. To go to longer periods between surveillances, it has to be shown that there is no material degradation in performance given the longer period before surveillances. (U8) (N1)

3.6.3.2.1 Setpoint drift
After a certain time, instrumentation has to be recalibrated, otherwise there is setpoint drift. It is desirable to do that online. But sometimes that can't be done without jeopardizing safety for the period of time the calibration takes, or without causing spurious trips. (U8)

Surveillance can't be done on some systems unless the plant is in an outage. If you wait more than 24 months for a surveillance interval on some instrumentation, the error band has to be assumed larger, and the window of operations begins closing. If you wait too long, the risk increases. Better analysis of equipment and how it changes with time is needed to reduce the assumed uncertainty. (V2)

3.6.3.3 Self testing
The AP600 has built-in, on-line testing. Digital systems should be used in safety systems for self testing rather than external checking. If self testing or diagnostic and monitoring techniques can be used rather than surveilling equipment or tearing equipment down, the problem can be diagnosed online. This allows plants shut down only when there is a problem, not at prescribed intervals. But the risk of a forced outage has to be balanced against the benefits of being able to run longer. (V2)

3.6.3.4 Other concerns
The ability to test online is a real limitation in current designs. Testing has to be an integral part of the design. Even if maintenance can be done at power, the post-maintenance testing probably can't be done to verify operability. Plants probably can't afford (from a safety perspective) to design for full flow testing of the HPSI while at power with the systems isolated. It could be hard to do.(P2)

Finally, there has to be confidence that when maintenance is done online, the probability of a plant trip is not significantly increased. (C4)

3.6.4 Predictive techniques

3.6.4.1 Maintenance based on predictive techniques
The trend in the industry is to do maintenance based on predictive capabilities such as pressure drops across filters, thermography, trends on leak-offs or leak-bys, capabilities of monitoring check valve performance by acoustics. All these are much better tools to determine when there is a tendency to have a degradation of performance in that component and when to go in and do maintenance, instead of performing maintenance on a specified time interval. The industry is being driven to this by economics. Why spend $5000 overhauling a valve when it can run twice or thrice as long. Just fix it when predictive indicators show there is a current or incipient problem rather than maintaining them blindly at fixed intervals. (U21)

If the consequences of failure are nuclear safety related, then the margin of safety can be increased by performing maintenance more frequently or by lowering the threshold level for predictive maintenance program. (U21)

3.6.4.2 Monitoring component life
Online monitoring is needed to verify that the predicted life can be achieved. Things like thermal cycles on nozzles as the plants goes through transients are important for long reactor life. The industry needs to know the number of cycles to failure given a crack exits somewhere. It needs performance indicators to predict when a component will fail. (U21) (V1)

3.6.4.3 Specific predictive techniques

3.6.4.3.1 Vibration monitoring
Vibration analysis can predict bear conditions, if something is rubbing, if something isn't balanced correctly, if a shaft is bent, drive belt degradations, and gear degradation. Vibration and noise monitoring should be used for on-line indication of failures in place of shutdown for inspection.[Ref.30] (U16)

3.6.4.3.2 Thermography
Infra-red thermography involves scanning of temperature profiles of electrical equipment, motors, room cooler heat exchanger tubes, uninsulated tanks, and some valves and bearings. If thermography shows unusual temperature profiles, then this is an indication of a degradation. (C4) [Ref.30] (U3)

3.6.4.3.3 Electrical signatures
When plants do surveillance tests today, they do them pass/fail. If technicians verify that I&C is within tolerances, then the I&C passes the inspection. But this system tells technicians nothing about the condition of the circuit from the transmitter through the penetration out. For life extension (and predictive maintenance) plants want to look at the integrity of the entire circuit. Is the penetration getting water in it? Is the transformer starting to fail? There are studies underway to look at condition monitoring. A computer is used to take an electronic signature of the circuit. When the signature is taken two years later, it is possible to tell what is degrading. Technicians can tell if there is in-leakage in a penetration. They can tell if there is a splice inside containment that has started to fail. This is very valuable because if the plant runs for 40 years, and the utility wants to extend plant life for another 20 years, the utility needs to have a good idea of whether the cables are any good. (C6)

BWR_#4 recently purchased a machine that takes electrical signatures of electronic circuitry, and trends it over time. It can be used to monitor degradation over time. They are going to take signatures of all of the MOVs during the next outage, and then begin trending them to predict when to replace or repair the motors, instead of waiting until the motor fails. (U3)

3.6.4.3.4 Lube oil testing
Lube oil analysis is used to minimize change-outs of systems with large oil reserves. [Ref.30]

3.6.4.3.5 Hydraulic testing
Hydraulic testing measures pump flows and differential pressures to determine equipment performance. [Ref.30]

3.6.4.3.6 Leak monitoring
Leak before break monitoring - plants have the ability to measure leakage from the primary side from an inventory balance. There are limits for unidentified and identified leakage from the primary system. If a crack forms in the primary, operators usually have time to investigate before it ruptures. (U20)

3.6.4.3.7 Batteries
Trending the specific gravity and voltage of battery cells can be used to predict which batteries will need to be replaced during the next outage. (U3)

3.6.4.3.8 Performance monitoring
BWR_#4 trends the start times on the EDGs. BWR_#4's EDGs usually start in 8.5 seconds. Recently, it took the EDG 9 seconds to start, which is still within requirements, but higher than they expected. They investigated and found that solenoids were gumming up due to contamination from a previous modification. This is an example of how performance trending can be used to indicate future degradations. (U3)

3.6.5 Maintenance policy

3.6.5.1 Steaming the plant
Plants can run very reliably for a short period of time (2 to 5 years), but then the neglect catches up with it and the plant is down for up to a year, or it runs poorly for the next couple of cycles. It's better to take a preventive maintenance outage than to run the plant too hard and pay for it later. Think about the oil in a car. A car can run very reliably without preventive maintenance for a short period of time. But if it goes too long without an oil change, it is going to destroy the engine. The same applies to nuclear power plants.(N2)

One PWR went through a period when they "steamed" the plant. It had a great capacity factor through neglect, and it's been hurting the reliability of the plant ever since. (U13)

One BWR started up in '69 and ran very well for about 10 years. But the necessary preventive maintenance was neglected, and the plant paid for this in capacity factor throughout the 1980s. (U15)

3.6.5.2 Maintenance philosophies

BWR_#5 had a very poor operating history in the early to middle 1980s. The philosophy was "what has to be fixed to get online?" That philosophy was changed to "what has to be done to get online and stay there?" The results were dramatic. BWR_#5 runs very well now. (U15)

The service people want to shut down more to keep the plant running and out of forced outages. The fuel people say to run longer to get better economics. (V2)

The industry is finding out that its perception of doing work during outages is not true. The best time to maintain some of the redundant portions of the plant is during operation because it's safer. Plants allow some components to run until failure because they don't cause shutdown, and it's cheaper to let them fail. (U14) (U21)

3.6.5.3 24 hour maintenance

PWR_#10 does 24 hour maintenance because they had to have the staffing present anyway to meet emergency response requirements. In addition, if the plant is running really well, doing online maintenance keeps the control room personnel alert. The result is good economics. (U15)

3.6.5.4 Over maintenance

PWR_#12 started out with a policy of rebuilding one of the RCPs every outage, but then began experiencing problems. They were over maintaining them. They then went 20 years without having a problem with an RCP. (U16)

3.6.6 Equipment performance

Running longer at steady state may in some cases be better for the equipment. When plants come back to power from an outage, they often have failures. This is because some of the cycling and technician-machine interactions have detrimental effects. (P4)

3.6.7 Spare parts

A significant cause of many extended outages is lack of spare parts. This can be corrected. BWR_#4 used to go into the switchgear, take a 4160 breaker out to have it overhauled or inspected, and send it to GE in Philadelphia to have the work done. There would be a weeks turnaround time before it came back. They were overhauling 100 breakers every outage, which was taking out some major electrical distribution components for a long time. Finally it was decided to purchase spares. This is much quicker, much easier, and much safer. This is a very effective example of where a little money in spare parts can improve outage performance. (U23)

Switzerland has a practice of having a spare circulating water pump available for change-out during an outage. This philosophy can be applied to many more plant systems. (U19)

The cost of storing a component amounts to about 25% of the total overall cost of the spare parts. (U3)

3.7 Materials condition

Material degradation is a serious concern for safe and reliable operation of nuclear power plants. It is important to minimize degradation. The following comments were made in this area.

3.7.1 Materials

Materials are going to be a limiting factor. Inconnel 690 for the steam generator tubes is probably the best designers can do with current materials technology. The cost of tube material is not that great when compared to the cost of the steam generator, so they are probably thinking that 690 is the best they can do. The rubber / elastomer diaphragms in valves in air and water systems are also a problem. (C4)

3.7.2 Erosion/corrosion

There are many esoteric issues in material corrosion - from microbiologically induced corrosion (MIC) to zebra muscles. There will always be a new disease for future plants. (C4)

Any new plant should be less susceptible to erosion/corrosion by design. This is accomplished through better material selection and chemistry control. It is also affected by the way the piping is set up. Sharp bends should be minimized in pipes and the transition region from 1 to 2 phase flow should be minimized. (P3)

3.7.3 Chemistry of fluids

The chemistry of primary water, feedwater, steam, closed cooling systems, and open cooling systems should be carefully controlled. Inter granular stress corrosion cracking (IGSCC) can probably be controlled with good chemistry control and materials selection. (C4) (P4)

Chemistry control has progressed significantly from its initial state. This has helped improve the condition of steam generator tubes. Chemistry is very important to continued operation of steam generators, and other plant components and systems. (U13) (C2) (U11)

3.8 Cycle length pressures

This category outlines concerns and experience associated with extended fuel cycles, mid-cycle shutdowns, and refueling outages.

3.8.1 Fuel cycle length

3.8.1.1 Plant experience

Early experience with extended operating times did not show the immediate gains that were expected because the systems were not sufficiently reliable or were not properly maintained. But recently, better preventive maintenance has allowed plants with extended cycles to achieve the reliability and gains that were expected. (P4) (P2)

- PWR_#7 1 & 2 are on 12 month refueling / major maintenance cycles. They have 28 day outages breaker to breaker. They can run at 92% capacity (minus forced outages). If they can achieve 28 day outages consistently and then run very reliably for one year, it will be very difficult to beat that even with longer cycle plants.(U14)

- PWR_#11 runs 18 months and gets very short outage times. If other plants could similar performance, there is little incentive to run longer. (V2)

- PWR_#3 has an average capacity factor of around 85% on a 12 month cycle. They are currently upgrading to an 18 month cycle. (U24)

- Japanese plants have 90 day outages every year. They maintain the entire plant. A longer cycle plant designed for online maintenance could save the Japanese a lot. But going from 5 to 10 years only picks up 2 to 3 points in capacity. It just isn't worth it. (V3)

The System 80^{+} has a two year cycle as a design criteria. (V1)

Utility 3 determined that their optimum fuel cycle length is 24 to 27 months. Going longer cycles begins to cost too much money for fuel. (U4)

3.8.1.2 Capacity factor arguments

For a very reliable plant with short refueling outages, there isn't very much to gain in terms of capacity factor by going to longer cycles. The AP600 is looking at 17 day refueling outages on an 18 month schedule, which is not unrealistic. On this cycle, the AP600 will have a maximum theoretical capacity factor of 96%. Longer cycle plants can't really do better than that. Prairie Island is doing 21 to 23 day outages. CANDUs originally planned to be down 10 days every 2 years. If plants can achieve this level of performance, there is nothing to gain by going to 5 years. (P3)

The track record for US maintenance outages is about 60 days. Initiatives are to go to 40 days, and then to 30 days, which is achievable. For an 18 month cycle with a 30 day outage, the plant's maximum hypothetical capacity factor is 94%. Running longer than five years will not improve capacity factor significantly, but could be very costly. (V3)

The position at GE and probably the rest of the industry is that five years is awfully hard to do and it's not economical. Two year cycles may not be economical. If a plant on a two year cycle is out an additional week during the outage or during the cycle, all of the expected economic gain is lost. A better strategy would be to use online monitoring, inspection, calibration, maintenance, and repairs to shorten outage duration. (V5) (U20)

3.8.2 Mid-cycle shutdowns

During the interviews, two opinions emerged. Both asserted that a mid-cycle surveillance and maintenance shutdown may be necessary. However, one opinion was that a short mid-cycle shutdown could improve reliability and could be economical. The other opinion was that a mid-cycle shutdown would negate the expected economic gains from going to longer cycles.

3.8.2.1 Required mid-cycle shutdowns

A lot of plants that are on two year fuel cycles have decided that it is expedient to shut down mid-cycle for a quick maintenance outage. This is not for Technical Specification requirements, it is just for better performance and less forced outages. This experience suggests that it is not probable that new plants will be able to run for 5 years reliably without shutting down. Examining why plants with two year cycles shut down will give indications of the systems that may need to be redesigned. (C4) (U24)

PWRs will have to inspect the steam generators mid-cycle on a five year operating cycle. (U24)

BWRs have troubles with primary stress corrosion cracking of the internals, and may need to do these critical inspections more frequently than every five years. (U24)

On first consideration, it appears that longer cycles are more economical. But for BWR_#4 to go to a three year cycle, it would have to shut down mid-cycle to do some maintenance and surveillances. If the mid-cycle outage is significant (~3weeks), then the economics of the longer cycle could shift negatively. (U1)

3.8.2.2 Economical mid-cycle outages

A short, economical mid-cycle outage may be possible. If the major outage is kept down to 35 days with a good, quick mid-cycle inspection, the plant could probably run at over 90% capacity.(U24) (C4)

Look at the maximum long term reliability of the plant. If that says it has to shut down every 18 months for 3 days, it may still be OK because the whole system isn't being taken apart. (P2)

Even if the plant has to shut down mid-cycle to do some maintenance, if the reactor head can be left on, that eliminates all of the difficulties and radiological control problems and safety problems associated with removing the head. (P2)

Plants can be run very economically if they can run as planned. It probably is not expensive to shut down for a week every year or two if the plant can shut down when it plans to. But it is important to run reliably in between. (P2)

3.8.2.3 Uneconomical mid-cycle outages

If the plant has to have a mid-cycle outage, and it's long, there is no benefit to going to longer cycles. (U15)

Plants should never go to a 5 year cycle if they will have to do a mid-cycle outage. (U21)

3.8.3 Refueling outages

3.8.3.1 Outage activities

There are about 10,000 items done during an outage, lumped into a few categories: check valve testing, pumps, and I&C calibration. Concentrating on the types of work done in refueling outages will yield valuable insights into how to redesign plants for shorter refueling outages and longer cycle times. (U4) (C4)

3.8.3.2 Reducing outage activities and duration

One benefit of online maintenance and inspections is that if you can do 9,000 of the 10,000 activities online that are normally done during the outage, the outage scope will be greatly reduced. This can reduce outage labor costs, and probably shorten outage time. Doing outage activities online will levelize the work load.(U14) (U15) (U21)

By going to longer cycles, the plant does not have to take off the head, transfer fuel, etc. every 18 months. This is an economic gain. (U21)

3.8.3.2.1 Critical path activities
BWR_#4 is in the process of taking work that can be done online out of their outage. Their critical path item is the ECCS. BWR_#4 has two 100% trains of ECCS. They can not start maintenance on either train until the reactor cavity is flooded (~1 week into the outage). If the plant had been designed with sufficient redundancy in the ECCS, work could have been performed online, year round, or at least significantly earlier in the outage. Currently, it is extremely restrictive because there is a very detailed list of systems necessary to backup the one available train of ECCS during the outage. (U19)

(See also Section 3.1.6.1.5)

3.8.3.2.2 Wet lift system
BWR_#4 just went to a wet lift system. With this new equipment, the cavity can be flooded as soon as the reactor head is removed. Previously, the cavity could not be flooded until after the dryers and separators had been removed. (U19)

3.8.3.2.3 Reactor vessel head detensioner
There are 56 holding bolts on the reactor head. They are currently detensioned in passes. There are machines available that can do this in one pass using four to six detensioners simultaneously. This can save 8 to 12 hours each side of the outage (a total of up to one day). (U19)

3.8.3.2.4 <u>Spares for quicker maintenance</u>
Having spare components, such as a spare reactor coolant pump motor or a spare circulating water pump, can significantly reduce outage times. This is an economic decision. (U19)

3.8.3.3 Longer cycles, longer outages
Refueling and major repairs during an outage usually take about 30 to 35 days for a very good plant. Refueling is almost never critical path. These plants currently stagger replacements and major maintenance between the outages because it is very difficult to fix everything at once. For a five year cycle, there could be an excessive number of required activities. For a five year cycle, the whole plant may have to be maintained during each refueling outage. The scope of maintaining the whole plant in a single outage in huge. (U24) (C4) (U21) (P2)

If all of the steam generator and turbine generator maintenance is done in a single outage instead of over a couple outages, there will not be a significant overall gain in the refueling outage time. The turbine generator will control the duration of the outage. Instead of three 50 day outages, the plant may have one 110 day outage. (U21)

3.8.3.4 Staggered outages
For utilities with two plants, it is better to have the plant outages scheduled out of phase. (V1)

3.8.4 Forced outages
There is concern that without periodic maintenance, there is the potential for increasing the forced outage rate. Examining forced outage causes will yield some data on what needs to be maintained or redesigned. (C4) (U21)

It is very expensive to shut down in mid-summer or in mid-winter. (P2)

3.9 Advanced technologies
The use of advanced technology and concepts that were not available for the first generation of nuclear power plants can significantly increase plant reliability and flexibility.

3.9.1 Advanced reactor concepts

3.9.1.1 Simplification
One of the goals of the Advanced Reactor Corporation (ARC) was to reduce capital investment. ARC has reduced the number of redundant and unnecessary valves, pumps, and piping. They have coupled this with passive concepts to achieve a much simpler and cheaper plant. The ALWRs have reduced valves by 50%. They have fewer automatic devices like MOVs and air operated valves. These goals may be fundamentally incompatible with longer cycles. (U14) (P3)

3.9.1.2 Advanced reactors

The SBWR focused on simplification of maintenance and lower personnel exposure. It was not aimed at a significantly extended fuel cycle. By taking out the recirculation pumps, plants will save a lot of maintenance work and costs. The goal was to make a better plant from an operational standpoint. (V4)

The ABWR was designed to meet all the safety function at minimum cost. Longer cycle designs have a different perspective: meet safety requirements, but also allow online maintenance. (V3)

The System 80^{+} FSAR is now available. It has the detailed design and Technical Specifications. (V1)

3.9.1.3 Innovative safety

Incorporation of a depressurization system solves the small break loss of coolant accident (SBLOCA) problem. But, it may be a source of risk for a LBLOCA. (N1)

3.9.2 Passive systems

3.9.2.1 Safety

Passive systems may not necessarily be superior from a safety perspective. Pumps can push a lot more water through for cooling than gravity and natural circulation can. But the passive plants will probably be safer by their greater simplicity and smaller size. There is also concern about flow instabilities. GE has been hindered by experimental data on flow instabilities in the SBWR. (U14) (N5)

3.9.2.2 Maintenance

ALWR designs have minimal active safety related systems in their designs. They use passive features like gravity driven flow and passive heat sinks to eliminate active components. These systems do not require much preventive maintenance. Fewer active components can reduce the amount of online maintenance that would be required for longer cycles. (P3) (C2) (U11)

The passive plants will presumably be easier to operate and maintain. They used passivity and simplification to eliminate complicated, problem systems. This can reduce maintenance and capital costs. Plants can achieve shorter outages too. (N5) (P4) (U14)

3.9.2.3 Regulatory risk

Passive systems are a greater risk from a regulatory perspective, but less of a risk from a public acceptance perspective. Adding redundancy is counter to the public's acceptance criteria (i.e. the public will trust simple passive safety systems compared to excessively complex systems). (U14)

3.9.3 Digital technology

3.9.3.1 Digital circuitry

3.9.3.1.1 Capability of digital circuitry
Digital circuitry is much more accurate than analogue circuitry. Current instrumentation calibrations drift, so that it is difficult to go up to two years between calibrations. Digital instrumentation is much more accurate, and can go longer between calibrations. A solid state diesel loading sequencer would allow quick, accurate self monitoring. The functional test could then be pushed out to five years. This could take three days off the critical path. (U3) (U23)

3.9.3.1.2 Effects of radiation on digital systems
The major limitation to digital circuitry is radiation hardening. At about 10^3 or 10^4 Rads total integrated dose (TID), the equipment starts failing. This limits where solid state technology can be used. (U3)

3.9.3.1.3 Fiber optic cables
Fiber optic cables could be used to decrease the number of cables in containment. The cable trays at BWR_#4 are filled, so if they want to add another wire, they have to run another conduit and do a safety analysis. (U3)

3.9.3.2 Digital controls

3.9.3.2.1 Performance of digital control systems
A full digital control system is an absolute necessity for any future plant. Digital systems are better than analogue control systems because they are not susceptible to all the noise, interference and oscillations that analogue systems are susceptible to. Many utilities are applying digital controllers in certain systems in their plants. Monticello was one of the first. They applied digital microcomputer technology to feedwater control many years ago. What was shown was that the reliability was tremendous in preventing feedwater transients which is a big cause of reactor trips and transients. (V1) (P2)

3.9.3.2.2 Regulatory position
Digital control systems are inevitable. All of the new reactor designs have digital control systems. It was a learning process for the NRC. But it is now accepted with a little concern until experience is gained, which will come from Sizewell B. There will be some struggles with the first one that goes through and gets licensed, but it's only a matter of time. (N2) (N5)

The only way to deal with the software reliability problem is to build some software and get experience. The writers will do the best they can, but they can never prove that all the bugs have been eliminated. (N2)

There will have to be some key backups in case there is a software failure that wipes the systems out. There will have to be a completely redundant backup system, but it could be a redundant, diverse digital system (like in the CE design). NRC convinced themselves that requiring an analogue backup was like requiring horse and buggy technology.(N2)

3.9.3.2.3 Utility position

One of the concerns with digital is what happened in Britain. The regulators accepted digital systems, as long as there was the old analogue hardware to back it up. This is not economical. It satisfies the regulators, but it is too expensive. (P2)

It is possible to use digital technology in non-safety areas. It is much more difficult in safety related areas. The difficulty is connecting all the systems together and getting NRC approval. The integrated package is not necessary, but is highly desirable. You don't get the full benefit of the technology if you don't integrate it. (P2)

3.9.3.2.4 Experience with digital control systems

Sizewell B is the only fully digital plant in the world. There have been significant problems with startup at Sizewell B because the systems were not available when they were supposed to be, the operators did not have confidence, and there was no backup. (C6)

Governor controls on auxiliary feed pumps were originally mechanical at PWR_#2. PWR_#2 ultimately went to a solid state control system because of the poor performance of the controls. PWR_#2 completely switched their RPS to a solid state system recently because it became uneconomical to run the old one. There were a lot of false signals generated, and parts were difficult to obtain. (U20)

The increased reliance on digital instrumentation and control systems in operating plants is an example of current plants utilizing advanced technology. (N1)

3.10 Safety

The final category is safety. For years, safety was the area of greatest attention and concern. The progress made to date should not be ignored, and there is still significant improvements that can be made in safety and safety analysis.

3.10.1 Loss of load events

Loss of load can last for a few seconds or much longer. But the plant reacts very quickly and trips for even short loss of load events. It trips the generator output breakers and the plant is down for a long time after that. (C2) (U11)

PWR_#9 has installed spare transformers, unit auxiliary transformers and GSU to reduce the chance of loss of offsite power. (C2) (U11)

3.10.2 Reactor scrams

The feedwater system and turbine generator are the major sources of scrams and down time. They are not nuclear safety systems, but they cause challenges to the reactor safety systems. (V3)

From a risk standpoint, the probability of core damage from a single trip is very low, but since the frequency of trips is so high, the overall CDF is significant. So if plant availability is increased, CDF may be decreased. (U20)

3.10.3 Interfacing LOCA

You can use leak monitoring between isolation valves or redundancy to alleviate interfacing LOCA concerns.(C2) (U11)

3.10.4 Accident analysis

3.10.4.1 In favor of using thermal margins

There is a lot of margin that can be obtained just by using better analysis techniques. (V2)

3.10.4.2 Opposed to using thermal margins

Plants are designing too close to plant operating limits. Perhaps they should allow for uncertainties or acts of God. Minor calculational and design mistakes can have great economic impacts. If there is a localized core melt due to improper analysis, a long shutdown and extensive decontamination are required. (U18)

3.10.4.3 Large break LOCA analysis

Best estimate LBLOCA analysis can be used to reduce uncertainties and allow for higher peaking factors and greater operational flexibilities. Better analyses can be performed using a statistical treatment of uncertainties. These analyses can be used to reduce the calculated peak clad temperature during the accident. (V2)

3.10.4.4 Small break LOCA

Once the LBLOCAs have been re-analyzed, the SBLOCA limits start to become more limiting. Going to better SBLOCA analysis techniques can generate additional thermal margins. (V2)

3.10.4.5 Other accidents

After the SBLOCA and LBLOCA limits have been fully utilized, the plant starts running into the deviation from nucleate boiling (DNB) limits on other accidents. Better techniques should be used there too. (V2)

3.11 Plant size

Small two loop plants are easier to maintain. They only have 1/2 of the steam generators to inspect. They require a lot less maintenance. They have better accessibility to the equipment. (U14)

The smaller plants like Ginna, Point Beach, Prairie Island, and Keewanie have had very good performance. Ginna has 30 day outages on a yearly cycle, and they have good capacity factors. Bigger reactors have a lot more equipment that needs to be inspected, and maintained. The larger plants become logistically more difficult to manage. A smaller plant like the AP600 or CANDU may be easier to operate. (N3)

Chapter 4 - Analysis methods

The purpose of this Chapter is to outline the methods that can be used to evaluate proposed design configurations and design modifications. This includes analysis methods for predicting performance and reliability. It also includes cost benefit analysis methods used to compare and evaluate designs based on cost considerations. Utilization of these methods will assure that informed decisions can be made on rational bases.

4.1 System availability analysis techniques

This section is intended to provide an overview of the typical analysis techniques available to the designer. These include basic probabilistic techniques, reliability block diagrams (RBDs). fault tree / event tree methods, Markov models, and simulation models.

4.1.1. Basic PRA

The intention of this section is to give a brief overview of the concepts necessary to perform reliability and availability analysis. For a more thorough treatment, see [Ref. 14], [Ref. 15], and [Ref. 16].

4.1.1.1 The hazard rate (also called the instantaneous failure rate), $\lambda(t)$

The hazard rate is defined such that [$\lambda(t)$ dt] is the probability that a component changes state in the differential time element dt about t, given that it has survived to t.

$$P_{fail}(t + dt) = \lambda(t)\, dt \tag{4.1}$$

Where $P_{fail}(t + dt)$ is the probability of a state change between times (t) and(t+dt). The hazard rate "exhibits the different life cycles of the component clearly and distinctly." [Ref. 14, p55]

4.1.1.2 The failure rate, f(t)

The failure rate is defined such that [f(t) dt] is the probability that a component fails in dt about t. The failure rate differs from the instantaneous hazard rate because the population decreases with time.

4.1.1.3 The reliability, R(t)

The reliability is the probability that a component did not fail prior to time t.

4.1.1.4 The cumulative failure probability, F(t)

F(t) is the probability that a component has failed by time t.

The hazard rate, failure rate, reliability and cumulative failure probability are related as follows [Ref.14, p58]:

$$\lambda(t) = \begin{cases} -\dfrac{d}{dt}[\ln R(t)] \\[2ex] \dfrac{f(t)}{1 - \displaystyle\int_{o}^{\tau} f(t)\, dt} \end{cases} \tag{4.2}$$

$$f(t) = \begin{cases} \lambda(t) \exp\left[- \displaystyle\int_{o}^{\tau} \lambda(t)\, dt' \right] \\[2ex] -\dfrac{d}{dt} R(t) \end{cases} \tag{4.3}$$

$$R(t) = \begin{cases} \exp\left[- \displaystyle\int_{o}^{\tau} \lambda(t)\, dt' \right] \\[2ex] 1 - \displaystyle\int_{o}^{\tau} f(t)\, dt \\[2ex] 1 - F(t) \end{cases} \tag{4.4}$$

$$F(t) = \begin{cases} \displaystyle\int_{o}^{\tau} f(t)\, dt \\[2ex] 1 - R(t) \end{cases} \tag{4.5}$$

4.1.1.5 Availability, A(t)

The instantaneous availability of a system is the probability that the system is operating at 100% capacity at time t. Availability differs from reliability in that it includes the possibility of repair and return to operation at some time after the failure. The "steady state" availability (A) is the value of the instantaneous availability as it approaches it's asymptote:

$$A = \lim_{t \rightarrow \text{plant life}} A(t) \tag{4.6}$$

4.1.1.6 Important failure rate distribution functions

4.1.1.6.1 Exponential distribution

For many components, the hazard rate is nearly constant over their useful life. This implies that failures are purely random, and that no deterioration in component condition exists over its useful life.[Ref. 14, p89] Under this condition, a particularly simple function is obtained for the failure rate distribution and for the reliability. It is convenient because only one parameter need be specified to determine reliability.

$$\lambda(t) = \lambda \tag{4.7}$$

This implies that

$$f(t) = \lambda \exp(-\lambda t) \tag{4.8}$$

and

$$R(t) = \exp(-\lambda t) \tag{4.9}$$

The form of f(t) is called the exponential distribution. We now focus on the mean time to failure and standard deviation of this distribution. The mean time to failure (MTTF) is defined as follows:

$$\begin{aligned} \text{MTTF} &= \int_o^{\infty} t f(t)\, dt \\ &= \int_o^{\infty} t\lambda \exp(-\lambda t)\, dt \\ &= 1/\lambda \end{aligned} \tag{4.10}$$

Similarly, the standard deviation of the failure rate distribution is defined as:

$$\sigma^2 = E[t^2] - (E[t])^2 \tag{4.11}$$

From this relation it is determined that [Ref. 14, p89]

$$\sigma = 1/\lambda \tag{4.12}$$

The exponential distribution will be used to characterize equipment failures in the subsequent models. This is a good first approximation for many components over their useful lives. However, modeling λ into the wear-out region may be a useful extension of the availability model for future analyses, and would involve a hazard rate growing in time.

4.1.1.6.2 The lognormal distribution

The lognormal distribution is discussed here because it will be used to model repair in one of the models in Chapter 5. Repairs are characterized by having diffuse repair times. The wide range of times required to fix a given component may make the exponential distribution unsuitable for modeling repair. Further, repair may not be able to be considered a single "random" process—because a random process may not take into account learning or things such as sequential steps described by exponential distributions. Thus, the lognormal (logarithmic normal) distribution may better model the data.

The theoretical justification for using the lognormal distribution to model repair is as follows. Repairs are considered as being composed of several steps—detection, diagnosis, preparation, execution, and testing—each of which may be described as an exponential transition. The sum of exponential processes is a gamma distribution. The lognormal can then used to approximate the gamma distribution, since it is easier to deal with.

It should be noted that sampling from the lognormal distribution yields the same steady state average availability as the exponential distribution with the same mean time to repair. However, it does affect both the standard deviation of the steady state availability and the instantaneous availability.

See [Refs. 14, 15, 16, 17 and 18] for detailed discussions of the lognormal distribution.

4.1.2 Reliability block diagrams (RBDs)

Reliability block diagrams are a basic, logical method of simplifying block representations of complex systems into equivalent simple systems. Although their names imply that they apply only to reliability, they can be solved for availability also. Some simple RBD logic structures follow.

For components in series [Ref. 15, p92]

$$R_{system}(t) = \prod_{n=1}^{N} R_n(t) = \exp\left\{\int_0^t \sum_{n=1}^{N} \lambda_n(\tau)d\tau\right\} \tag{4.13}$$

For N fully redundant identical components in active parallel (as opposed to standby), the reliability is given by [Ref. 15, p92]

$$1 - R_{system}(t) = \prod_{n=1}^{N}[1 - R_n(t)] \tag{4.14}$$

Although the above equations are solved for reliability, they are equally valid for availability, because the logic used in the derivation is the same.

Further, Equation 4.14 can be extended to r-out-of-n logic, and non-identical components.

4.1.3 Fault tree / event tree analysis

For simple risk based calculations, fault tree / event tree analysis is often sufficient to obtain realistic reliability values. For a complete treatment of fault trees and event trees, see [Ref. 14]. Essentially, fault trees and event trees attempt to accomplish the same objective, but from different approaches.

4.1.3.1 Fault trees

Fault tree analyses start by defining the system boundaries. Next, an undesirable "top event" is identified, and the question, "What can cause this top event to occur?" is asked. In this respect, fault tree analysis works backwards from the outcome to generate the combinations of events that cause it. [Ref. 14, p.173]

4.1.3.2 Event trees

Event tree analyses also begin by defining the system boundaries. Basic event tree analyses then take the opposite approach of fault trees. Event tree analyses identify precursors to undesirable events. An event tree analysis asks "What event could happen that would affect the system adversely?," and then proceeds in a forward manner and identifies all the possible outcomes and the consequences of those outcomes. [Ref. 14, p.168-173]

4.1.3.3 Limitations of fault trees and event trees

Fault tree / event tree analyses are mostly static, in that they give a snapshot of system reliability. Event trees are "semi-dynamic" in that they follow a sequence of events in time, but they will not yield the availability as a function of time or changing variables. The introduction of repairs into fault trees makes them cumbersome at best. The introduction of repairs into event trees may introduce an infinite logic loop, causing the size of the event tree to become infinite. To perform an availability analysis over long periods of time, repairs become an important and even dominant factor. Fault / event tree analysis is generally not flexible enough to perform a time dependent availability analysis on an operating power plant.

4.1.4 Markov models

A Markov process is a stochastic process "whose future probabilistic behavior is uniquely determined by its present state." [Ref. 14, p.222] Markov modeling is used to analyze systems of components which can be described by random failures and random repair times. As such, a Markov process is "memory-less," since "knowledge of the present decouples the past from the future." [Ref. 14, p.222-223] Although random failures and repairs may not be the best way to describe the system, they usually do not greatly affect the unreliability and unavailability calculations. [Ref. 15, p.120]

The first step in a Markovian analysis is the identification of all of the possible system states. For a large system, the number of possible states a system can occupy becomes unmanageably large. For this reason, reduction techniques become necessary to analyze large systems. [Ref. 19, p.38]

From the set of system states, a set of first order differential equations are constructed to describe the rate of transfer in and out of each state. Under the assumptions of constant transition probabilities, this set of linear, first order differential equations can be solved by using Laplace transform, matrix exponentiation, or time integration techniques. [Ref. 19, p38] Note that exact, analytical solutions to Markov models are limited to very simple systems of components.

For a simple overview of Markov processes and current research in this area, see [Ref. 19] For a introductory mathematical treatment of Markov processes, see [Ref. 14] or [Ref. 15].

4.1.4.1 Modeling a simple component

Consider the availability of a simple pump to take water from an input and deliver it to the output. The pump has an exponential failure rate, with instantaneous failure rate, $\lambda = 1 / (MTTF)$. The pump is also described by an exponential repair rate, with instantaneous repair rate, $\mu = 1 / (MTTR)$. The initial state of the system is 100% capacity. Figure 4.1 (a) shows this pump schematically, and Figure 4.1 (b) shows the Markov diagram for the pump. The two possible states are 100% capacity and 0% capacity.

The Markov model for this system can be expressed as a set of coupled, first order differential equations:

$$\begin{aligned} dP_o(t)/dt &= -\lambda P_o(t) + \mu P_1(t) \\ dP_1(t)/dt &= -\mu P_1(t) + \lambda P_o(t) \end{aligned} \tag{4.15}$$

Where $P_o(t)$ is the probability that the pump is in state 0 at time t, and $P_1(t)$ is the probability that the pump is in state 1 at time t.

Noting that the time dependent Availability is just $P_o(t)$, this set of equations can be solved for the time dependent availability, A(t), using Laplace transforms [Ref. 15, p.120-143]

$$A(t) = \frac{\mu}{\mu+\lambda} + \frac{\lambda}{\mu+\lambda} e^{-(\mu+\lambda)t} \tag{4.16}$$

This is the time dependent availability for the hypothetical pump in this example. More importantly, however, Equation 4.16 is the general form of the availability for any component that undergoes exponential failures and repairs between two states.

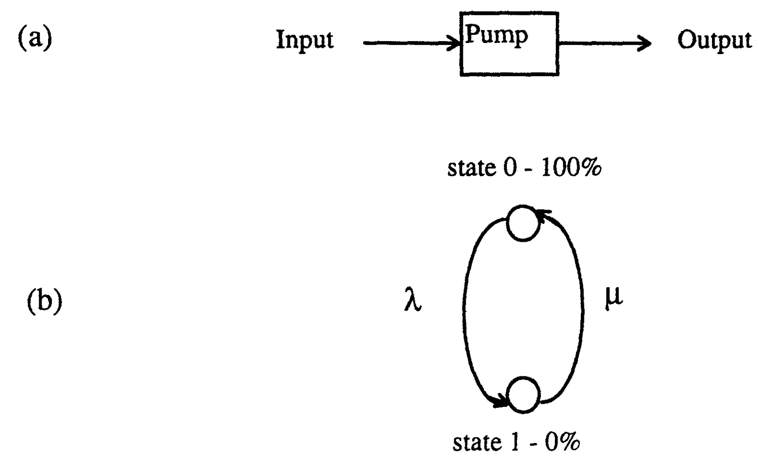

Figure 4.1 - Markov diagram (b) for a single pump (a)

4.1.4.2 Limitations of Markov models

Markov models involve matrices that become extremely large for complex systems. Therefore, simplifications and regroupings must be performed to keep the analysis within computational capabilities. Unfortunately, with these simplifications some of the insights into the system's behavior are lost.

Also, as mentioned, failures and repairs are treated as random processes. Markov models cannot treat non-exponential transitions in a straight forward manner. They cannot model time dependent transition probabilities or dependencies. This is the real limitation for Markov models. Real systems are characterized by complex interactions, and continuous state transitions. To model real systems using Markov models, serious simplifications may be necessary, which can invalidate results.

Further, they cannot easily model phased mission problems. This complication is circumvented by performing separate Markov analyses with the outputs from the $(n-1)^{th}$ mission being used to define the initial state of the $(n)^{th}$. However, this is somewhat cumbersome.

Finally, all of the possible system states must be known beforehand. For these reasons, Markov models are good as a first approximation, but have limited applications for complicated, dynamic modeling.

4.1.5 Direct simulation (monte-carlo based)

Direct monte-carlo simulation is the final and most powerful method discussed. A general definition of a simulation follows:

"A simulation of a system is the operation of a model that is a representation of the system. The model is amenable to manipulation that would be impossible, too expensive, or impractical to perform on the system it portrays. The operation of the model can be studied and from it properties concerning the behavior of the actual system can be inferred." [Ref. 20, p1-1]

Simulation can be used to predict the effects or performance of proposed systems, system modifications, procedural changes, an operational modification, or any physical modification, before actual construction or implementation. This can be a cost effective method for exploring many options before selecting the "best."

Monte-carlo simulation can be used to model systems where operations or transitions are governed probabilistically rather than by predetermined sequences of events, although predetermined interactions can be modeled also. Simulation is completely flexible. It can be used to model time dependent, non-exponential transitions, dependencies, external events, phased missions, repairs, maintenance and testing. It can be used to model almost anything that happens in the real system.

Random number generators are used to model probabilistic transitions. Predefined and user defined probabilistic sampling distributions are used to describe component failure rates, repair rates, testing, or any process that is described by a statistical distribution. For each set of random numbers, the program is run and the results are recorded. This can be thought of as an experiment. After many such "experiments," the results will converge to the mean values, and the availability of the system and it's individual components can be determined.

4.1.5.1 Setting up the model

According to Russell, setting up a simulation model involves 8 steps [Ref. 20, p1-13 to 1-15]:

1. Articulate simulation goals

It is important to have clearly defined goals. This involves specifying the relationships that will be studied and determining the information that needs to be obtained. It is the problem statement.

2. Analyze the system to determine appropriate level of detail for the model.

This step defines the amount of detail to be incorporated into the model. It makes no sense to precisely model electrons flowing through a coil in a pump if what is desired is the overall availability of a power plant. More likely, the pump will be described by a set of failure modes and associated failure probabilities.

"The real art of model building is the ability to capture the essence of a system without building in extraneous information into the model and yet omitting nothing of importance." [Ref. 20, p1-14]

3. Synthesize the system (realize the model).

This is the actual construction of the model. Careful thought should be given to the program structure and flow.

4. Collect and prepare input data

By this step, the model will be ready to run except for input data. During this step, data should be obtained and condensed into a usable format. Representation of data in the simulation program includes [Ref. 20, p1-15 to 1-16]:

- Direct input of observed phenomena
- Reduction of data to an arbitrary distribution function
- Use of built-in random deviate generators to approximate the observed phenomena analytically.

5. Verify model correctness

This is to assure that the code accurately reflects the intended model.

6. Validate model results

This assures that the code accurately reflects the real world system. Proof of the validity of a monte-carlo simulation model is virtually impossible. In the best case, results can be compared to the real world system to enhance our confidence that it will generate valid results, but it can not be proved that the model absolutely represents the real system under all circumstances, configurations and external influences.

7. Prepare for system experiments

This is the real value of simulation. Once we are confident that the model is generating good predictions, we can begin to experiment on the system. This allows low cost analysis of various system configurations

8. Analyze experimental results

4.1.5.2 When does simulation become necessary?

1. When there are dependencies between different elements in the model.
   - repair dependencies: there is typically a certain level of manpower to repair failures. This can be handled by a repair supervisor routine, which simulates realistic repair actions and dependencies.
   - when the state of one component affects the state of other components
   - If you consider performance as a continuous variable, simulation is a natural way to handle this.
   - If performance degradation at one point implies something about the performance at another point.
2. When time dependence must be considered.
   - time dependence of capacity factor
   - aging
   - transient response
   - control system modeling

4.1.5.3 Advantages / disadvantages of simulation

It should be clear that monte-carlo simulation is an extremely powerful modeling technique. However, it is not without its drawbacks. Much of the following list is taken from [Ref. 19].

4.1.5.3.1 <u>Advantages</u>

1. Once constructed, a model can be used to analyze proposed design or policy changes.
2. Simulation models are usually easier to apply than analytic methods.
3. Simulation does not require many of the simplifying assumptions required to make analytical solutions tractable. Thus, modeling is completely flexible.
4. Simulation is sometimes the only method capable of generating a solution.

4.1.5.3.2 <u>Disadvantages</u>

1. Simulation models may become costly in terms of running time and model construction time.
2. Simulation is sometimes used when analytic models will suffice.

4.1.5.3.3 <u>Limitations</u>

There are two major limitations on simulation modeling: statistical uncertainties and input data accuracy.

The uncertainty is equal to $1 / \sqrt{N}$, where N is the number of trials. For large, complex systems, the number of trials required to obtain good statistics may become prohibitively time consuming.

The quality of input data is another major limitation. Theoretically, if the failure distributions are known exactly, then monte-carlo simulation accuracy will be limited only by statistics, which can be improved with progressively larger numbers of trials. However, the exact failure distributions are rarely known.

4.1.6 Comparison between reliability block diagrams, Markov models and simulation for two simple cases

As the first step in validation of the monte-carlo simulation model that will be constructed later, the results of two simplified models with the same basic program structure as the larger model are compared to the analytical solution generated by a Markov analysis and reliability block diagrams.

4.1.6.1 Example 1

Determining the availability of the simple system given in Figure 4.2 (a). The pump undergoes exponential failures and repairs. The pump takes water from reservoir A, and ejects water into reservoir B. The availability of reservoirs A and B are unity.

MTTF = $1/\lambda$ = 200 hours

MTTR = $1/\mu$ = 40 hours

4.1.6.1.1 <u>Reliability block diagram analysis</u>

The answer to the reliability block diagram is trivial—it is just the availability of a single pump that undergoes exponential failures and repairs, and is given in Section 4.1.4.1.

4.1.6.1.2 <u>Markov analysis</u>

As was seen in discussed in Section 4.1.4.1, using Markov modeling an analytic solution can be obtained for this simple system by constructing the set of first order differential equations describing the pump transition probabilities, and then solving using Laplace transforms:

$$A(t) = \frac{\mu}{\mu+\lambda} + \frac{\lambda}{\mu+\lambda} e^{-(\mu+\lambda)t} \qquad (4.17)$$

Substituting in for μ and λ, the availability equation is obtained:

$$A(t) = 0.8333 + 0.1667 \exp[-0.03\ t] \qquad (4.18)$$

4.1.6.1.3 <u>Monte-carlo simulation</u>

This problem was also constructed in the monte-carlo simulation programming language Simscript II.5. [Ref. 21]

4.1.6.1.4 <u>Comparison of RBD, Markov, and simulation results</u>

The results are plotted in Figure 4.3. As seen in the graph and Table 4.1, the results of monte-carlo simulation agree with the analytic solution obtained from Markov modeling. Thus, for a simple component, simulation mimics analytic solutions.

4.1.6.2 Example 2

This example is the same as the first example, except instead of one 100% capacity pumps, the system utilizes two 100% capacity pumps in active parallel. See Figure 4.2 (b). These pumps have the following failure and repair parameters:

MTTF = 200
MTTR = 40

4.1.6.2.1 Reliability block diagram analysis:
Using reliability block diagrams and Equation 4.14, the availability of the system is given by:

$$A_{system}(t) = 2A_{single\ pump} - (A_{single\ pump})^2 \qquad (4.19)$$

Substituting in Equation 4.16 for the availability of a single pump and simplifying yields:

$$A(t) = \frac{\mu^2 + 2\mu\lambda}{\mu^2 + 2\mu\lambda + \lambda^2} - \frac{2\lambda^2\left(s_2 e^{s_1 t} - s_1 e^{s_2 t}\right)}{s_1 s_2 (s_1 - s_2)} \qquad (4.20)$$

where $s_1=-2(\mu+\lambda)$ and $s_2=-(\mu+\lambda)$.

Substituting in for μ and λ, the following equation is obtained:

$$A(t) = 0.9722+0.9259(-0.03\exp(-0.06t)+0.06\exp(-0.03t)) \qquad (4.21)$$

4.1.6.2.2 Markov analysis
A set of coupled, first order differential equations can be constructed to represent the state transition diagram in Figure 4.2 (b). An analytic solution can then be obtained through Laplace transforms. [Ref. 15, p.120-143] The solution obtained through Markov analysis is identical to Equations 4.20 and 4.21.

4.1.6.2.3 Simulation
A simulation model was constructed to model the operation of the system in Figure 4.2(a). The results are compared to the other methods in section 4.1.6.2.5.

4.1.6.2.4 Comparison of RBD, Markov, and simulation results
Figure 4.4 compares the results of a monte-carlo run to the Markov / RBD solution to the same problem. As can be seen in Figure 4.4 and Table 4.2, the results agree well.

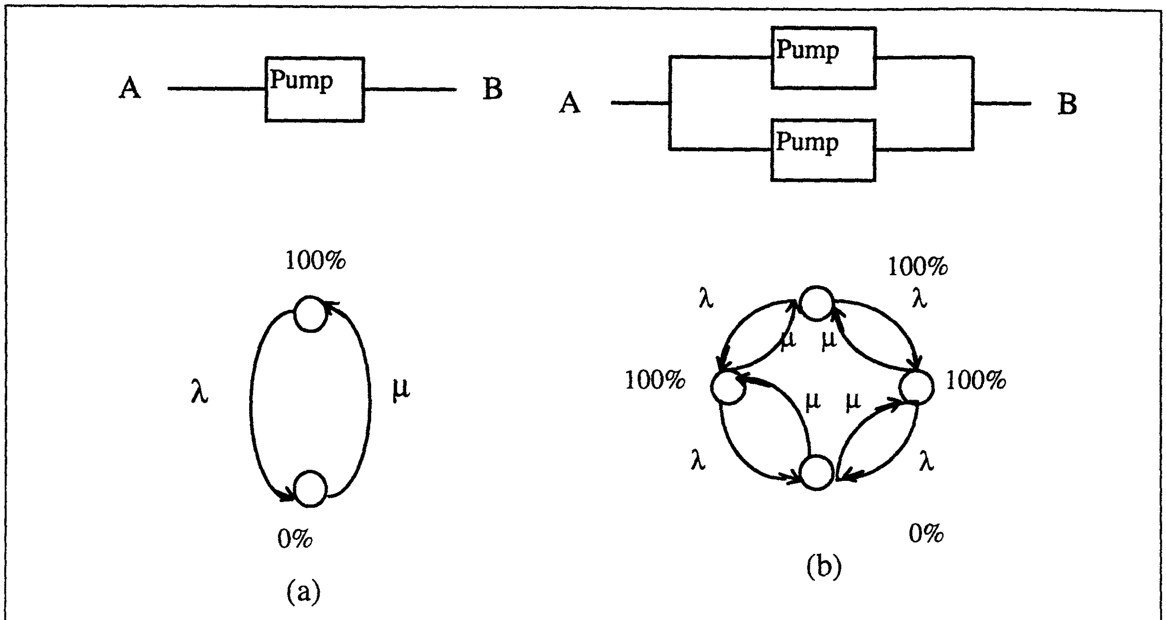

Figure 4.2 - Markov diagrams for single pump (a) and parallel pump (b) systems

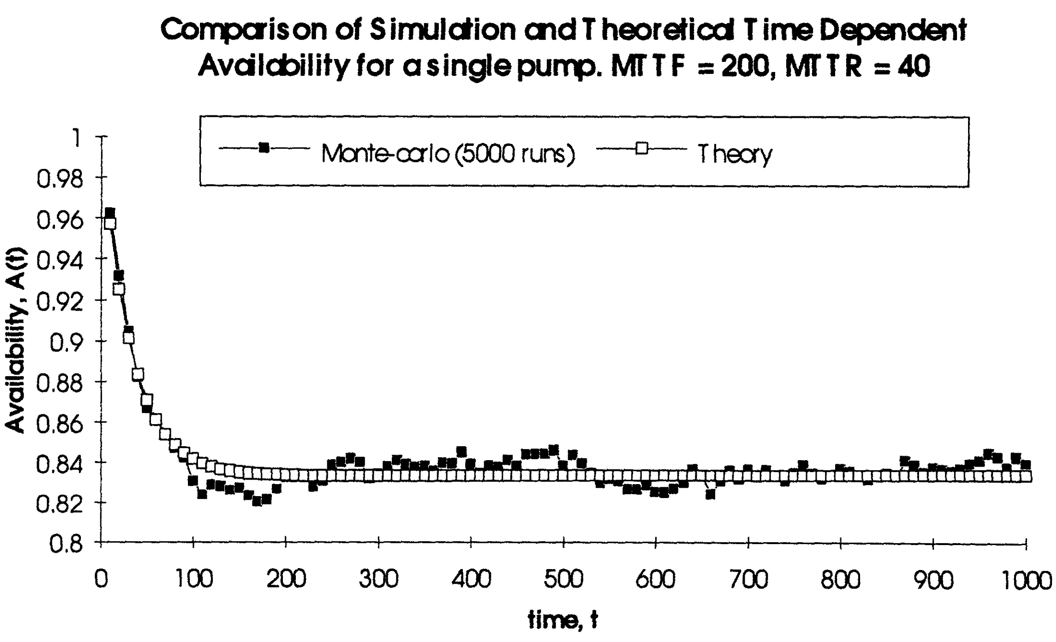

Figure 4.3

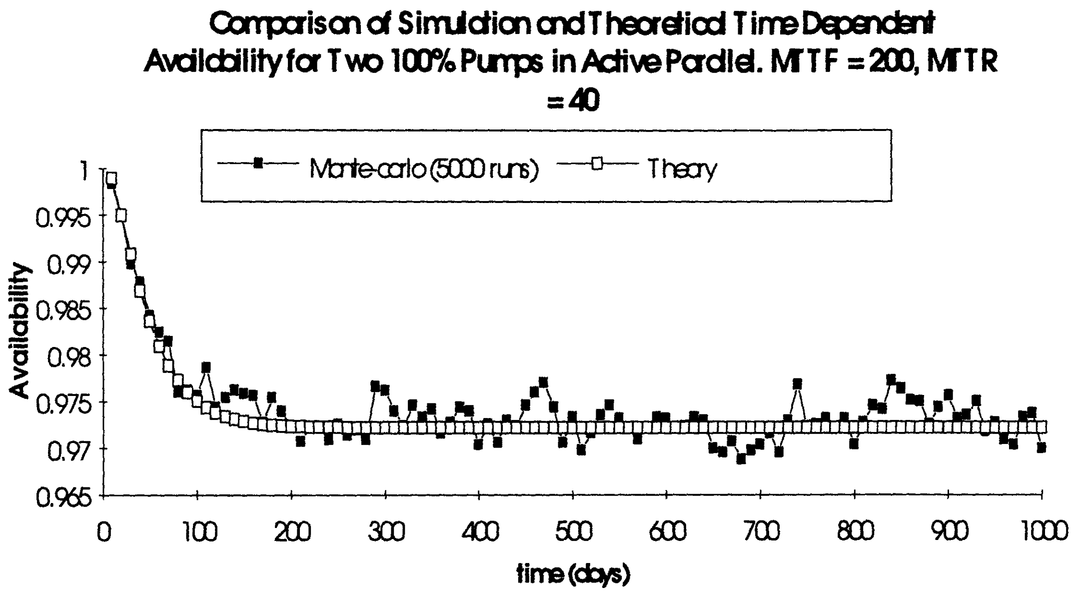

Figure 4.4

	Average availability	$\sigma_{\text{Average availability}}$
Monte-carlo, 1000 cycles	0.8400	.0032
Markov Model / RBD	0.8381	

Table 4.1 - Comparison of Markov and simulation average availabilities for a single pump over 1000 days

	Average Availability	$\sigma_{\text{average availability}}$
Monte-carlo, 1000 cycles	0.9744	.0009
Markov Model / RBD	0.9736	

Table 4.2 - Comparison of Markov and simulation average availabilities for parallel pumps over 1000 days

4.2 Cost benefit analysis methods

The purpose of this section is to outline two cost benefit analysis methods which can be used as decision tools:

- deterministic cost benefit analysis
- statistical cost benefit analysis

4.2.1 Traditional cost benefit analyses

The traditional method of cost benefit analyses has been a deterministic approach. Under this methodology, the engineer develops a "point estimate" of the expected engineering costs and benefits associated with a specific project, and makes a decision based on these estimates. The problem with this type of analysis is that it does not take into account the uncertainties associated with the expected costs or benefits. This fact is not lost on designers, and they typically impose a more conservative "rule of thumb," and do not accept a design modification unless it pays for itself over again plus some margin (perhaps up to a factor of 2 or 3). This is analogous to saying, "We're pretty sure the numbers are right, but for conservatism, let's build in a margin of error." Sensitivity analyses can also be used to assess the impacts of uncertainties; however, they are not addressed in this thesis. [Ref. 31]

4.2.1.1 Example

Lets go through an example to illustrate this method. Consider a company that has just purchased for $10M the rights to pump water from a reservoir to the townspeople. See Figure 4.5. The contract lasts 10 years. The company will receive $10,000 per day for providing this service. It receives no revenues for those days when water is not available. The company is now considering which pumping system it should purchase to deliver water to the town (Figure 4.6). Option 1 has an availability of 0.83 and costs $3M. Option 2 has an availability of 0.97 and costs $5M. Table 4.3 summarizes the data.

	Option 1	Option 2
Average Availability	0.83	0.97
Investment Cost	$3,000,000	$5,000,000
Maintenance Cost	$100,000 / yr	$150,000 / yr
Time Horizon	10 years	10 years

Table 4.3 - Analysis data for hypothetical pumping systems

The real opportunity cost of investment (r) = 10%.
Capital outlay = $10M
Revenues when operating = $10,000 / day
Revenues when not operating = $0

All we have to do now is to chose the option with the largest net benefit (NB). Note that the net benefit is defined as the total expected benefits (B) less total expected costs (C) :

$$NB = B - C \tag{4.22}$$

Choosing the option with the largest net benefit is equivalent to performing a present discounted value analysis for each to the two options, and choosing the most positive. First, note that for Option 1, we expect to have the system available 83% of the time, or 303 days per year. This translates to revenues of \$3.03 M per year. Option 2 is expected to be available 97% of the time, or 354 days per year at revenues of \$3.54M per year.

Let us evaluate the net benefit of each option by performing a discounted value analysis for both the benefits and the costs.

<u>Option 1:</u>

$$B_1 = \$3.03M\sum_{m=1}^{10}\frac{1}{(1+r)^m} = \$18.62M \tag{4.23a}$$

$$C_1 = -\$10M - 3M - \$0.1M\sum_{n=1}^{10}\frac{1}{(1+r)^n} = -\$13.61M \tag{4.23b}$$

$$NB_1 = B_1 - C_1 = \$5.01M \tag{4.23c}$$

<u>Option 2:</u>

$$B_2 = \$3.54M\sum_{m=1}^{10}\frac{1}{(1+r)^m} = \$21.75M \tag{4.24a}$$

$$C_2 = -\$10M - \$5M - \$0.15M\sum_{n=1}^{10}\frac{1}{(1+r)^n} = -\$15.92 \tag{4.24b}$$

$$NB_2 = B_2 - C_2 = \$5.83M \tag{4.24c}$$

Since the net benefit of Option 2 is greater than the net benefit of Option 1, Option 2 is the better choice from a deterministic standpoint. This is the best choice given the information available. Note, however, both options are attractive - they are both expected to make money. Now let's look at a more sophisticated method of cost benefit analysis.

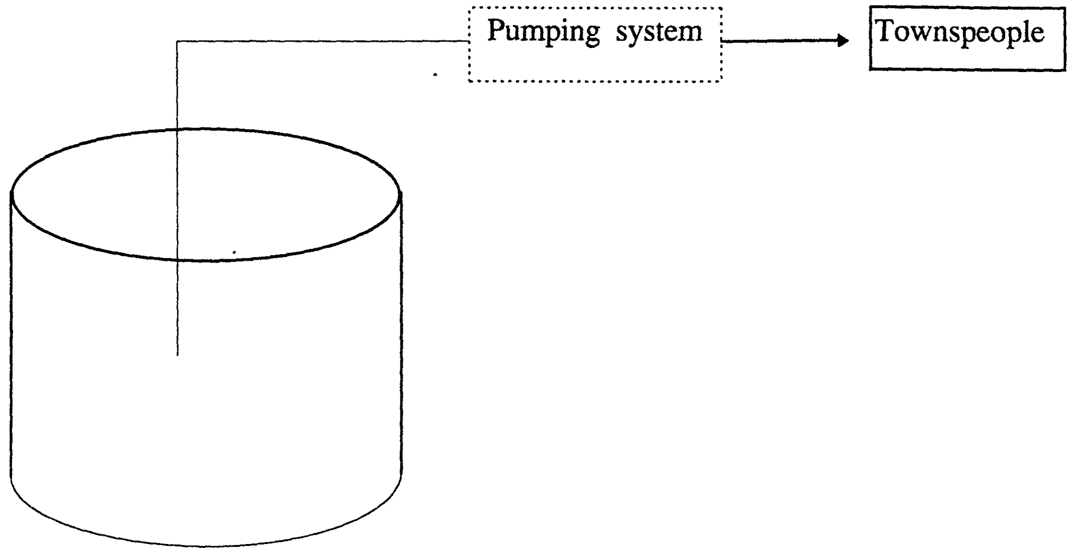

Figure 4.5 - Pumping flow diagram.

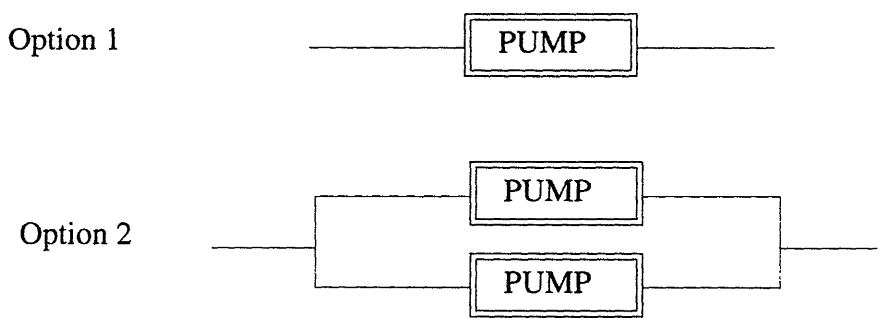

Figure 4.6 - Available pumping systems.

4.2.2 Statistical cost benefit analysis methodology

The deterministic approach to cost benefit analyses is a good first approximation. However, a methodology that explicitly addresses statistical uncertainties is a more powerful and informative technique. It allows the designer or operator to make decisions based on all the information available, and will yield a probability distribution function which describes the expected net benefit. For a complete and excellent treatment of this methodology, see [Ref. 22]

4.2.2.1 A more realistic description of expectations - probability distributions

Until now, expected costs and benefits were expressed as point quantities. That is, values were expressed as point estimates. A more informative description of expectations is the probability distribution. Under this approach, uncertainties are explicitly stated. Consider the following example of the expected availability of the pumping system discussed in the previous example.

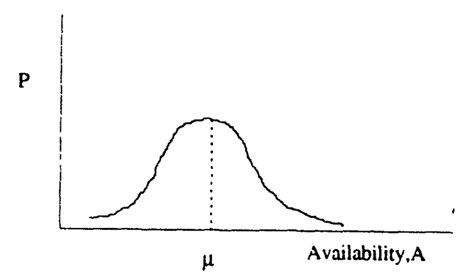

Figure 4.7 - Availability (A) distribution for Option 1 pumping system

The distribution in Figure 4.5 shows that although there is a mean expected availability associated with the pumping system, there is uncertainty in the exact value. The point estimate used before assumes the mean value, μ_A, is the "correct" value. In fact, we do not know exactly what the real value of the availability (A) is, but we know that A is described by the above probability distribution. To better understand this, consider how failure data for a system may be derived. An investigator speaks with several different individuals who own the model of the component in question. He then asks how often the pump fails. Each individual will probably have a slightly different answer, because pumps do not always fail at the same time. This distribution can be constructed as follows.

1. Discretize the failure frequency into finite, manageable ranges.
2. The probability that the "true" failure rate of the component is within the failure frequency range in question is the number of point failure rates in that frequency band divided by the total number of failure rates reported in every frequency band.

What is obtained is a set of doublets describing the discrete probability distribution.

Mathematically, let $A_1, A_2, \ldots, A_n$ denote the discrete availabilities and let $p_1 = p(A_1)$, $p_2 = p(A_2)$, ..., $p_n = p(A_n)$ denote the probabilities associated with those availabilities being the true availability for the particular pumps in question. Thus, the following set of doublets are obtained:

$$\mathbf{A} = <p_1,A_1>, <p_2,A_2>, \ldots, <p_n,A_n> = \{<p_i,A_i>\} \tag{4.25}$$

The same operation can be performed to obtain a probabilistic distribution describing the costs associated with a given scenario:

$$\mathbf{C} = <q_1,c_1>, <q_2,c_2>, \ldots, <q_n,c_n> = \{<q_i,c_i>\} \tag{4.26}$$

Returning to the previous distribution (A), note that what is needed is the probability distribution of the benefit rather than the availability of the system. The distribution for the expected benefit is derived subsequently, but first, let us review some discrete probability mathematics.

4.2.2.2 Probabilistic mathematcis

4.2.2.2.1 Probabilistic addition

Let **x**, **y** be probabilistic distributions described by:

$$\begin{aligned} \mathbf{x} &= \{<p_i, x_i>\} \\ \mathbf{y} &= \{<q_j, y_j>\} \end{aligned} \tag{4.27}$$

If x and y are independent, then [Ref. 22]

$$\mathbf{x} + \mathbf{y} = \{<p_i, x_i>\} + \{<q_j, y_j>\} = \{<p_i q_j, x_i + y_j>\} \tag{4.28}$$

4.2.2.2.2 Probabilistic multiplication

We now define $\mathbf{z} = \mathbf{x}*\mathbf{y}$ as [Ref. 22]

$$\mathbf{z} = \{<p_i, x_i>\} * \{<q_j, y_j>\} = \{<p_i q_j, x_i\, y_j>\} \tag{4.29}$$

4.2.2.3 Determining the benefit

Now, let's return to the problem at hand. We want to know the probability distribution describing the availability associated with a particular decision. However, we want the benefit. For this example, the benefit (B_i) associated with a given availability is just

$$B_i = k\, A_i \tag{4.30}$$

Where k is a scalar factor converting availability points into benefit.

K is the discounted value per year of availability. Since each day of availability translates into $10,000, and there are potentially 365 days of availability per year, k is given by

$$k = \$3.65M \sum_{n=1}^{10} \frac{1}{(1 + r)^n} \tag{4.31}$$

Now, note that multiplying a probability distribution by a scalar quantity affects only the abscissa, not the ordinate. Defining B as the benefit distribution, we see that:

$$\mathbf{B} = \mathrm{k}\,\mathbf{A} = \langle p_1, kA_1\rangle, \langle p_2, kA_2\rangle, \ldots, \langle p_n, kA_n\rangle = \{\langle p_i, kA_i\rangle\} \tag{4.32}$$

4.2.2.4 Determining the net benefit

We now have probability distributions for the cost and benefit for each option. The next step is to obtain the net benefit probability distribution (N) for each of the options. By definition,

$$\mathbf{N} = \mathbf{B} - \mathbf{C} \tag{4.33}$$

To illustrate this example, a probability distribution for the cost and benefit will be assumed. First note that the benefit is expressed as a 2 by M matrix and the cost is expressed as a 2 by N matrix, where M and N are the number of discrete ranges that the benefit and cost probability distributions have been divided into. The result of probabilistic distribution addition (or subtraction) of the benefit and the cost yields a 2 by (N*M) matrix. For simplicity of this example, let M = N = 3.

From the example of Section 4.2.1.1, we know the mean expected benefit and cost associated with option 1. Now, suppose we knew a little more about the expected benefits and costs, and that they were given by Figures 4.8 and 4.9. Note that the mean of the benefit and cost distributions have not changed, only the statistical uncertainties are explicitly treated.

Next, Equation 4.33 is evaluated using the arithmetic operations of Equation 4.28 to yield the following matrix in Table 4.4, the net benefit probability distribution [Ref. 22]:

Table 4.4 - Net benefit matrix

Net Benefit Probability		Benefit		
		P1, B1	**P2, B2**	**P3, B3**
COST	**Q1, C1**	(0.063, -6.07)	(0.125, -3.38)	(0.063, -0.69)
	Q2, C2	(0.125, 2.33)	(0.250, 5.02)	(0.125, 7.71)
	Q3, C3	(0.063, 10.73)	(0.125, 13.42)	(0.063, 16.11)

The next step is to plot the data in Table 4.4 on a cumulative probability curve, and to use curve fitting to smooth the curve. [Ref. 2] This has been done, and is shown in Figure 4.10.

Next, note that the probability density is just the slope of the cumulative probability curve. [Ref. 22] To obtain a discrete probability density distribution for Option 1, the range has been split into four discrete ranges, and the slope of the cumulative probability curve has been evaluated over these ranges. The results are given in Figure 4.11.

4.2.3 Results

There is an interesting point worth noting. The expected value of the net benefit is positive, but there is a significant probability that the net benefit could be negative. This is a fact that does not come out of a deterministic analysis. It could be that the pump's performance was overestimated, and that the costs were underestimated and the net effect is that the company loses money.

The drawback to this methodology is its complexity. Frequently, there is not enough known about the expected cost and benefit distributions to justify assigning a probability distribution over a point value. Further, the discrete probabilistic mechanics of the problem are cumbersome and time consuming.[Ref. 22] However, if the probability distributions describing the costs and the benefits are well known, and it is important to know the full range of outcomes, this methodology is excellent. Further, the monte-carlo simulation method of analysis lends itself to generating statistical distributions for the expected benefit.

4.3 Summary

The capabilities of several probabilistic availability analysis methods were discussed. The results of reliability block diagram, Markov, and simulation analysis methods were then compared to demonstrate the agreement between methods for straight forward problems. It was also pointed out that to model complex, real world, time dependent systems with interdependencies, monte-carlo simulation is necessary. Since one of the ultimate goals of this line of research is to model such systems in sufficient detail to accurately predict actual system performance, monte-carlo simulation was selected as the analysis method of choice.

To compliment the probabilistic system performance analysis methods outlined in the first part of Chapter 4, two cost benefit analysis methods were outlined. It was seen that deterministic cost benefit analyses are straight forward calculations. However, they are limited in their treatment of uncertainties, and may result in decisions being made with an incomplete appreciation of the uncertainties associated with the problem. A statistical cost benefit analysis explicitly accounts for all uncertainties. A statistical cost benefit analysis can be used to generate a more complete understanding of the economic risks and benefits associated with a particular decision. However, the statistical analysis is more difficult and cumbersome and requires a more complete understanding of the distributions describing the expected costs and benefits.

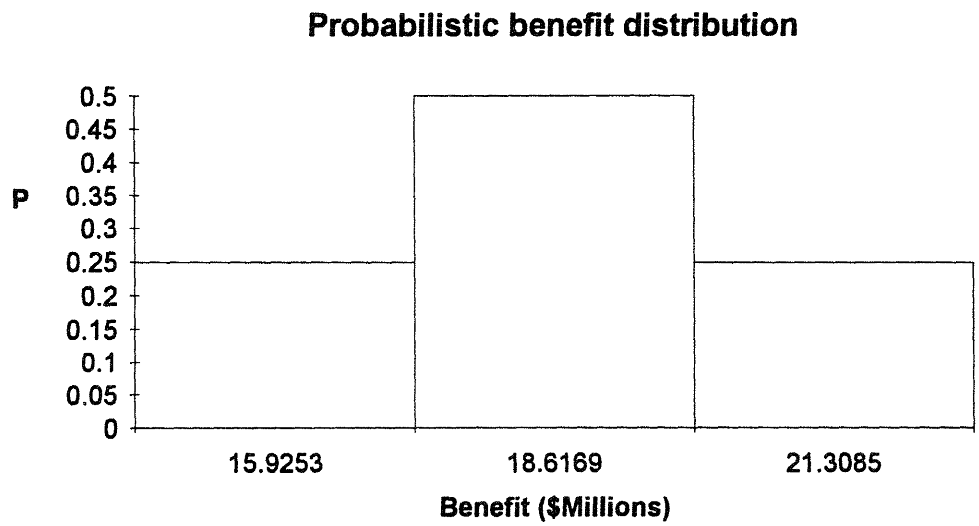

Figure 4.8

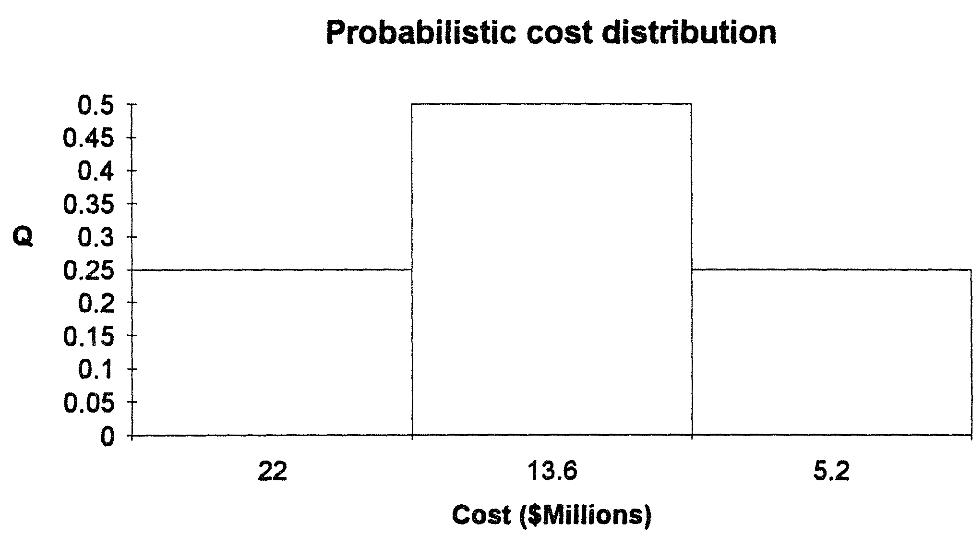

Figure 4.9

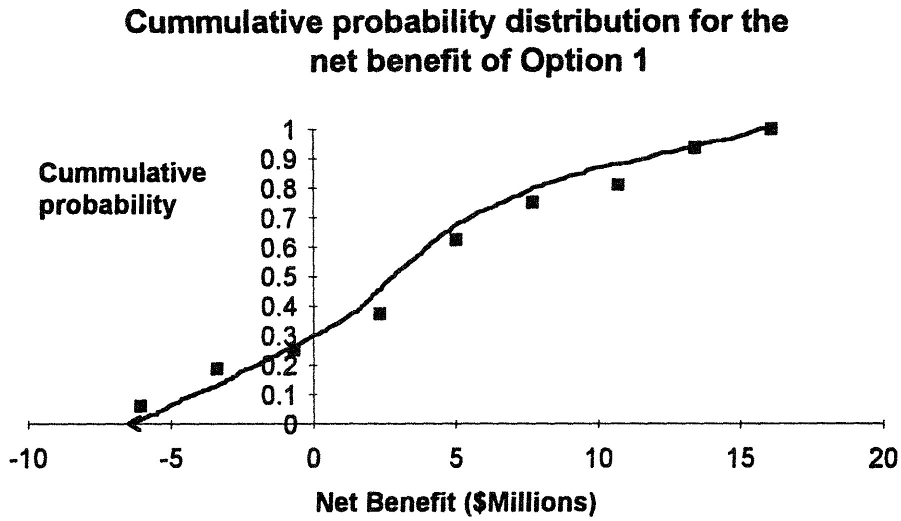

Figure 4.10

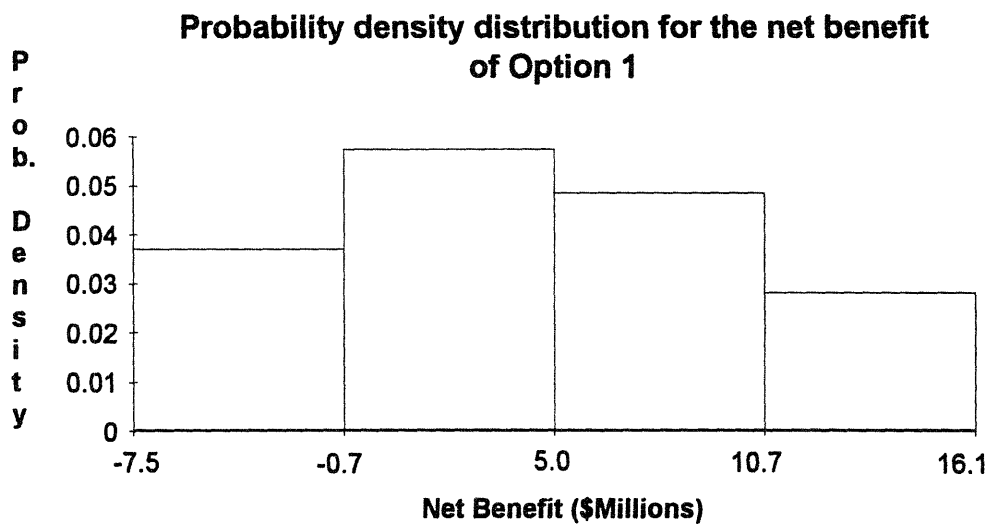

Figure 4.11

Chapter 5 - Analyses

In Chapter 5, a simplified monte-carlo model of a nuclear power plant is developed. Interviewees' suggestions from Chapter 3 are utilized to identify the feedwater system as a system worth modeling in more detail. A simplified version of this model is compared to an analytical model to validate its structure.

The purpose of Chapter 5 is then to apply the strategies of Chapter 2 to the model to identify directions in which performance can be enhanced. Then the model is utilized to evaluate the efficacy of these proposed design modifications.

5.1 Plant model

5.1.1 Block model of a nuclear power plant

The first step in constructing a block power plant model is to identify major systems to be modeled, and to define the scope of the model. The model to be constructed is based on a standard PWR schematic. The basic systems to be included in the model are those major systems required for power production. Safety and standby systems will not be included in the original model, but can be incorporated later. Also not explicitly modeled are control systems and valves. This is intended as a first pass of the major systems required for power production.

5.1.1.1 Primary side

Modeled

1. Reactor
2. Reactor coolant pump
3. Pressurizer
4. Steam generators

Not modeled

1.CVCS
2. Safety systems
    - -injection systems
    - -emergency electrical power
    - -shutdown systems
3. Electrical supply
4. Instrumentation

5.1.1.2 Secondary side

Modeled

1. Turbine-Generator
2. Condenser
3. Feedwater

Not modeled
1. Extraction steam for feedwater heating
2. Switchyard
3. Circulating water system
4. Pressure relief valves
5. Control systems
6. Instrumentation

The result is a block diagram of the power plant. In its simplest form, lumped availability parameters are assigned to each block. If availability parameters are chosen to include factors not explicitly included in the model, good overall plant availability predictions can be calculated. However, this is not a very sophisticated approach, and it is desirable to model these systems in more detail. It is clearly beyond the scope of a master's thesis to develop a detailed, working model of a nuclear power plant, with all of its interdependencies, complexities and tens of thousands of components. Therefore, a compromise approach has been adopted. One of the functions of this thesis is to demonstrate how to develop more detailed models by example. The feedwater system will be modeled in greater detail, although still not thoroughly modeling the actual system.

This more detailed model is then utilized in conjunction with the other lumped parameter systems to quantify the effects of system design modifications. The ability to analyze the effects of proposed system design modifications is extremely valuable, as will be seen. The modifications are based on the strategies of Chapter 2.

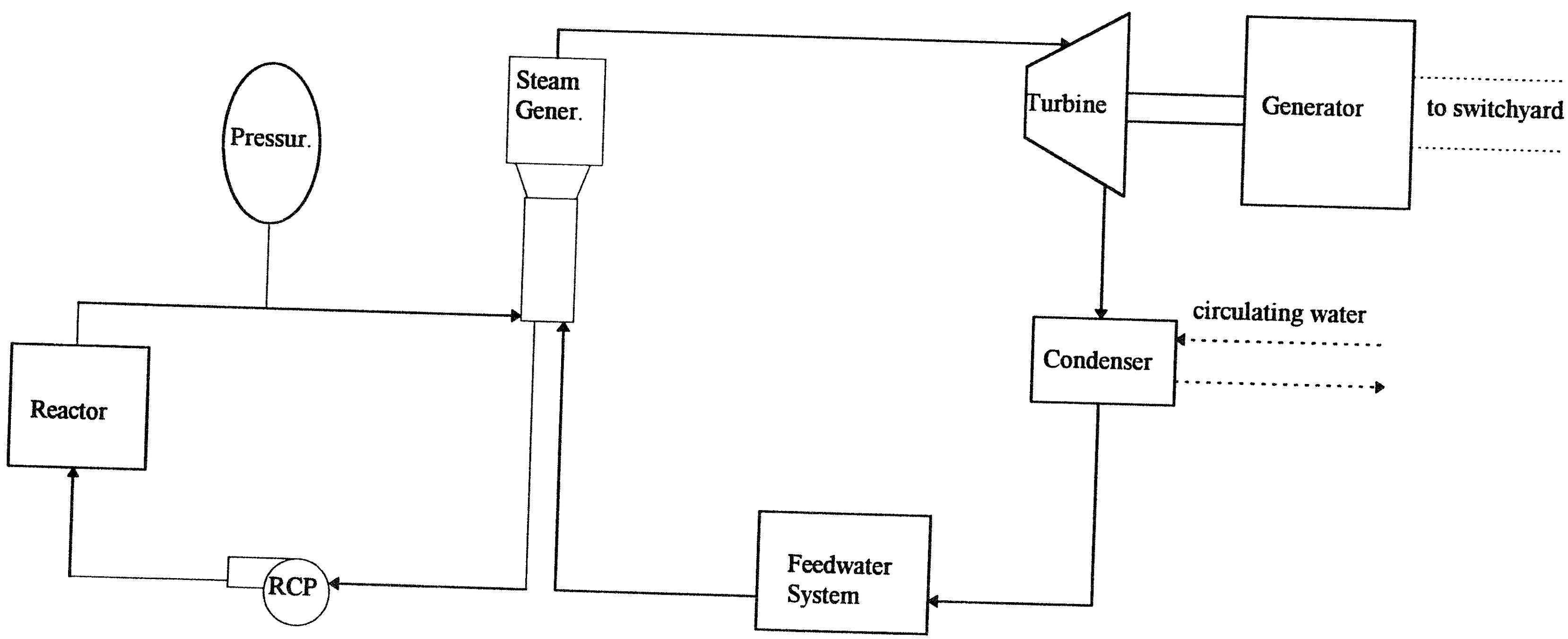

Figure 5.1 - Block diagram model of a PWR

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5.2 Modeling the feedwater system

During the interviews with industry representatives, several systems were identified as deserving design re-evaluation. Among those identified was the feedwater system. This is a system common to all commercial US power plants, BWR and PWR. A PWR feedwater system was chosen for analysis because PWRs comprise the majority of operating power plants around the world, and because the feedwater system has consistently contributed to significant capacity factor losses.

The feedwater model constructed is shown diagramatically in Figure 5.2. This particular feedwater system is a simplified model based on the Seabrook Preliminary Safety Analysis Report (PSAR). For a complete description of the feedwater system, see [Ref. 23]. For convenience, a brief description is included below with the list of equipment modeled.

Components included in the feedwater system:

1. Condensate pumps. The condensate pumps are motor driven. They take water at a pressure of 1.2 psi and 100 degrees F from the condenser and inject it into the feedwater system at a pressure of 280 psi. [Ref. 23]

2. Steam jet air ejector condensers. The steam jet air ejector condensers condense steam from the steam jet air ejectors, and return it to the condenser hotwells. They also provide feedwater preheating for a small efficiency boost. [Ref. 23]

3. Steam gland condensers. The steam gland condensers are heat exchangers that condense turbine gland seal steam while preheating the feedwater. They also slightly boost thermal efficiency. [Ref. 23]

4. Drain coolers. The drain coolers cool low pressure heater condensate while preheating the feedwater. The drain coolers boost thermal efficiency slightly. [Ref. 23]

5. Low pressure heaters 1 through 5. The low pressure heaters heat the low pressure feedwater using extraction steam from the main turbine and crossover piping. The main purpose of the low pressure feedwater train is to provide feedwater heating to improve thermal efficiency, reduce thermal stresses on the steam generator, and improve steam generator control [Ref. 23] [Ref. 28]. The temperature at the intake of the feedwater pumps is 380 degrees F. [Ref. 23]

   The drains from the high pressure feedwater heater are cascaded to the highest low pressure heater. The drain from the second highest pressure heater is pumped to the suction of the feedpumps. "Heater drains from the four lowest pressure heaters are cascaded" and eventually dumped into the condenser. The two lowest pressure heaters are located in the condenser neck. All heaters are single pass, U-tube design. [Ref. 23]

6. Feedwater pumps. The feedwater pumps boost feedwater pressure to the steam generator operating pressure (about 1200 psi) The feedwater pumps are turbine driven, centrifugal pumps. [Ref. 23]

7. High pressure heaters. The high pressure heaters use extraction steam to heat the high pressure feedwater before it enters the steam generator. This improves steam generator control, thermal stresses and efficiency. [Ref. 23] [Ref. 28]

Not modeled

1. Valves - flow control, check, bypass
2. Sensors
3. Extraction steam feeding shell side of heat exchangers
4. Reactor trips due to feedwater transients - this is something may be worth including in future models. It could be included as a straight probability that the transition between power states is successful or not.
5. Startup failures.
6. Plant shutdown failure rates. For model simplicity and verifiability, it was assumed that the failure rates in shutdown conditions were the same as in operation. The next logical extension of the model would be to include failure rates as a function of plant state.
7. Drain pumps.

5.2.1 Failure data

It should first be noted that equipment failure data is an area where further research should be performed. The data obtained for this report are generic and are thought to be reasonable and consistent with available references. However, they are not as exact as would be desirable for a detailed engineering calculation with real economic ramifications. Therefore, the results obtained should be reasonable, but should be repeated with more component / model specific data before any specific conclusions are made.

Failure rate and repair rate data were estimated for the components and systems to be modeled. The data were chosen to be consistent with references, including

1. WASH 1400 data - provides general ranges for component failure and repair rates.
2. Data provided by Northeast Utilities Operating Company's PRA group
3. Seong, Ph.D. thesis, MIT, 1987
4. NUREG-1272, NRC, AEOD, 1992 Annual Report
5. Interviews with industry representatives

The failure data used in this analysis are summarized in Table 5.1. The repair rate distribution is listed here as lognormal; however, for simplification in the validation section repair rates are assumed to be exponential, with the same mean time to repair.

Component	failure rate distribution	MTTF (days)	Repair rate distribution	MTTR (days)	σ (MTTR)
1. Condensate pumps	exponential	1000	Lognormal	2	2
2. Steam jet air ejectors	exponential	1000	Lognormal	20	20
3. Steam gland condenser	exponential	1000	Lognormal	30	30
4. Drain Cooler	exponential	5000	Lognormal	30	30
5. Low pressure heater	exponential	5000	Lognormal	30	30
6. Feedwater pump	exponential	1000	Lognormal	2	4
7. High pressure heater	exponential	5000	Lognormal	30	30
8. Steam generator	exponential	10000	Lognormal	60	60
9. Turbine-Generator	exponential	500	Lognormal	15	15
10. Condenser	exponential	5000	Lognormal	30	30
11. Reactor pump	exponential	2500	Lognormal	20	20
12. Reactor	exponential	5000	Lognormal	10	10
13. Pressurizer	exponential	5000	Lognormal	20	20

Table 5.1 - Component reliability data

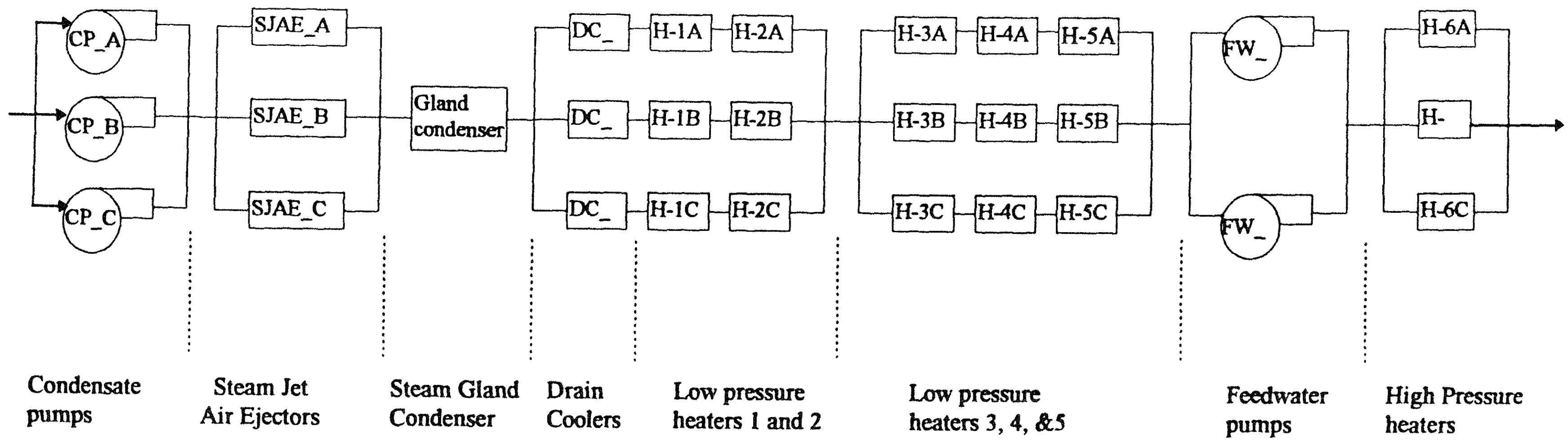

Figure 5.2 - Simplified model of the feedwater system [Ref. 23]

<u>Feedwater system key:</u>

1. CP_x	Condensate pump x
2. SJAE_x	Steam jet air ejector x
3. Gland condenser	Steam gland condensers from turbine
4. DC_x	Drain cooler x
5. H-1x	Low pressure heater train 1, component x
6. H-2x	Low pressure heater train 2, component x
7. H-3x	Low pressure heater train 3, component x
8. H-4x	Low pressure heater train 4, component x
9. H-5x	Low pressure heater train 5, component x
10. H-6x	High pressure heater train 6, component x
11. FW_x	Feedwater pump x

5.2.2 Benchmarking the monte-carlo plant availability model against a reliability block diagram analytical solution

Utilizing the reliability block diagram method, an analytical solution was obtained for the entire model, under some simplifications. The simulation model was slightly simplified to facilitate comparison to an analytical solution.

5.2.2.1 Assumptions

1. Exponential failure and repair transitions.
2. Availability (in the strict sense as defined below) was calculated.
3. Slightly modified success logic.

5.2.2.2 Success logic

The availability of a system at time t is the probability that the system is 100% available to perform it's intended safety function. Therefore, the logic has been simplified to eliminate the possibility of partial success states. Therefore, if the capacity of any series system is less than 100%, then the plant is defined as "failed" in the respect that the availability is zero, even if the system can still operate at a non-zero capacity less than 100%. The capacity of the following systems were modified to allow 1-out-of-1, 1-out-of-2, and 2-out-of-3 logic. The success logic is listed in Table 5.2. The success logic for all components outside of the feedwater system is 1-out-of-1.

Table 5.2 - Success logic for analytical availability analysis

	Component Description	Component Capacity	Success Logic
1. CP_x	Condensate pump x	50%	2-out-of-3
2. SJAE_x	Steam jet air ejector x	50%	2-out-of-3
3. Gland condenser	Steam gland condenser	100%	1-out-of-1
4. DC_x	Drain cooler x	50%	2-out-of-3
5. H-1x	Low pressure heater train 1, component x	50%	2-out-of-3
6. H-2x	Low pressure heater train 2, component x	50%	2-out-of-3
7. H-3x	Low pressure heater train 3, component x	50%	2-out-of-3
8. H-4x	Low pressure heater train 4, component x	50%	2-out-of-3
9. H-5x	Low pressure heater train 5, component x	50%	2-out-of-3
10. H-6x	High pressure heater train, component x	50%	2-out-of-3
11. FW_x	Feedwater pump x	100%	1-out-of-2

The hand calculation was facilitated utilizing Mathcad, and is presented in Appendix D. The availability of each component was calculated based on the failure and repair parameters listed in Table 5.1. Then reliability block diagram simplifications were performed to calculate the availability. For redundant trains of a subsystem, the availability of each train was identical. This simplifies the availability calculation for each subsystem.

The comparison between reliability block diagram availability calculations and the monte-carlo simulation results are listed in Figure 5.3. There is remarkable agreement between the monte-carlo simulation model and the hand calculation.

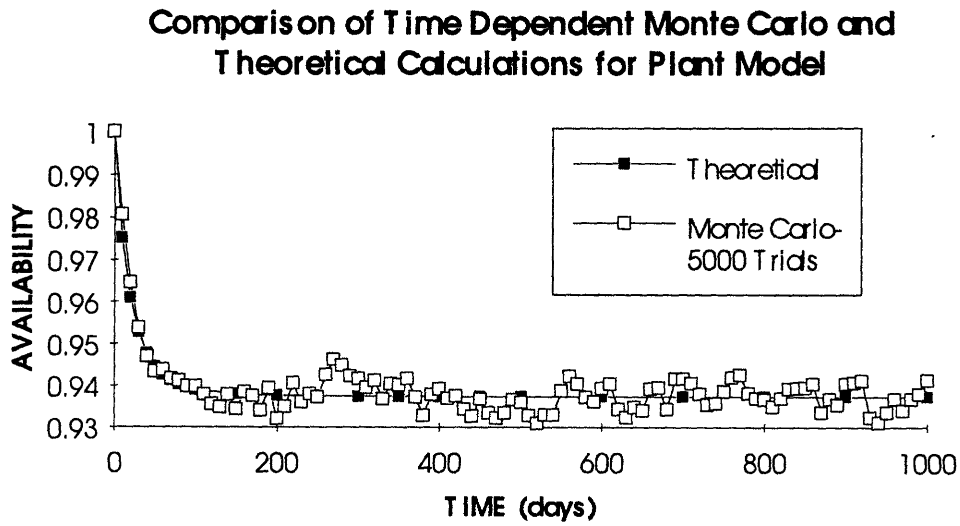

Figure 5.3

The data points on the graph are the instantaneous availability values for the monte-carlo and the theoretical calculations. The number of "experiments" was 5000. If an average availability is calculated (which is of greater interest for analysis purposes), the statistics for the monte-carlo run improve considerably, and agree very well with the theoretical average availability. This parameter is listed in Table 5.3

	Mean Availability	Standard Deviation of Mean Availability
Monte-carlo	0.938	+/- 0.002
Theoretical	0.937	

Table 5.3 - Average availabilities for analytic and simulation models over a 1000 day period.

5.2.3 Towards a more realistic plant model

We now have analytical verification of the efficacy of the monte-carlo calculations of the simplified plant model in predicting availability and reliability performance. This section is intended to demonstrate the types of calculations and analyses that can be performed once an effective, accurate model has been constructed.

The plant model utilized for this analysis is still significantly simplified and general relative to the actual physical plant. Other analysis techniques such as RBDs or Markov models may be more suitable for this particular problem. However, when a serious attempt is made to accurately model a power plant, with all the dependencies and experiential data, other analysis techniques will fail. Therefore, the monte-carlo approach, which will become necessary, is utilized in this present analysis.

To make the plant model more realistic, the strict definition of "availability" should be relaxed. In fact, what will be calculated will be the average value of capacity factor as a function of time, and a mean overall predicted capacity factor. This differs from the previous example in that partial success states will be accounted for. In many instances, the plant can run at reduced power while a parallel component is being repaired. Although the plant is still producing electricity, the strict "availability" is defined as zero because the plant is not operating at 100% capacity. The capacities of each component for this more realistic calculation are listed in Table 5.4.

Failures were still assumed to occur according to an exponential failure rate distribution. This is consistent with equipment behavior during the operational life of equipment. It does not well model equipment that is aging past its intended operating period without maintenance or repair. This should be addressed in future models.

Repair rates were assumed to follow a lognormal repair rate distribution. The lognormal distribution was chosen because repair rates can vary significantly. There are numerous examples of repairs taking much longer than expected in the nuclear industry. This may be due to improper diagnosis, poor planning or an unavailability of spare parts (an emerging issue). Whatever the case, this selection is drawn from the data and conclusions of WASH 1400.

Table 5.4 - System capacities

Component	Number of components	% Capacity per component
1. Condensate pumps	3	50
2. Steam jet air ejectors	3	33
3. Steam gland condenser	1	100
4. Drain Cooler	3	33
5. Low pressure heater	3	33
6. Feedwater pump	2	50
7. High pressure heater	3	33
8. Steam generator	1	100
9. Turbine-Generator	1	100
10. Condenser	1	100
11. Reactor pump	1	100
12. Reactor	1	100
13. Pressurizer	1	100

5.2.4 Perturbations

5.2.4.1 Cycle length perturbations

The first analysis performed will be to examine the effects of increased cycle length on expected average operating and overall capacity factors. The base plant model described above was run for 5000 cycles to calculate the expected operating capacity factor as a function of time. From these time dependent data, the average operational and overall capacity factors were calculated as a function of cycle length.

Figure 5.4 displays the results of the average operating capacity factor as a function of cycle length. It is seen that as the plant goes to longer and longer cycle lengths, the operating capacity factor decreases. However, it approaches a steady state asymptote after about 600 days.

Figure 5.5 displays the results of the average overall capacity factor as a function of cycle length for a base 60 day outage length. The curve illustrates the point made early in Chapter 1 - going to longer cycles can significantly improve capacity factors for a given outage length. It is not clear, however, that the outage duration is independent of cycle length, and this should be kept in mind when viewing the cycle length results. With this in mind, it is seen that capacity factor increases rapidly at first, but then the decreasing operational capacity factor and the saturation effect of the reduced overall outage time become apparent.

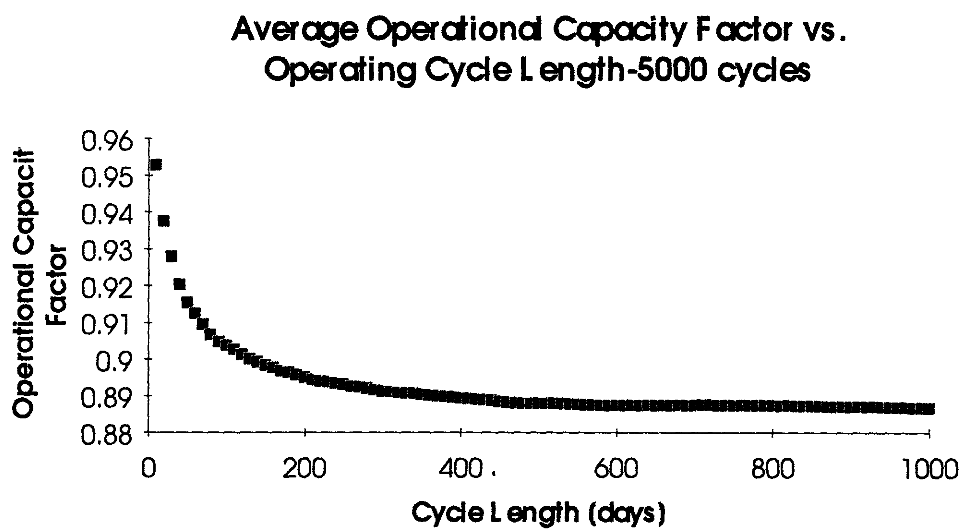

Figure 5.4

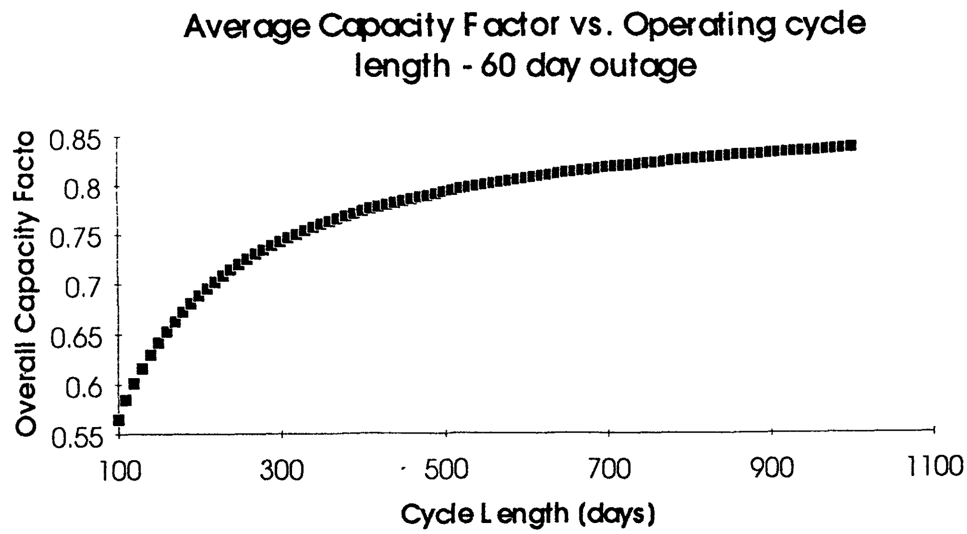

Figure 5.5

5.2.4.2 Effects of redundancy

The next parameter examined was redundancy. For example, in the case of the feedwater system, redundancy can improve the modes of operation in which repair can be performed. In instances where sufficient redundancy does not exist, increasing redundancy can allow repairs to be performed while the plant is at full power, rather than at reduced power levels. Under the base configuration, the feedwater system is a secondary side system and is isolatable. Therefore, trains can be repaired while the plant is still running, although maybe at a reduced power level.

First, the effects of individually adding an extra train to each isolatable subsystem was examined. This was intended to identify which individual systems had the greatest potential for savings. Next, the effects of adding an additional, completely redundant train of feedwater was examined. The results are summarized in Table 5.5. For calculated increases in capacity factor less than the standard deviation of the mean operational capacity factor, it was assumed that no conclusions could be made and that the increased capacity factor was negligible. Systems that appeared to have the greatest potential for improved availability were the steam jet air ejectors, the low pressure heater trains, the steam gland condensers and the high pressure heaters. Not surprisingly, these are the components with long mean times to repair. Although the active components tend to fail more frequently, their repair times are also shorter, resulting in a small contribution to overall capacity factor loss. The value of adding a completely redundant feedwater train was on the order of 5 points in overall capacity factor. For a 1000 MWe power plant selling electricity at a rate of $30/MWh-e, this translates into roughly $13 million per year in extra revenues. If this is sufficient to offset additional capital costs plus some margin of uncertainty, an extra feedtrain should be implemented.

Description	# trials	mean OCF	Standard Deviation	Stand. Deviation of mean OCF	increased OCF	CF	increased CF_60 day outage
Base Case	5000	0.8870	0.0544	0.0013	0	0.8368	0
Redund. Condensate pumps	1000	0.8871	0.0515	0.0046	~0	0.8369	~0
Redund. Steam Jet Air Ejectors	1000	0.9051	0.0511	0.0048	0.0181	0.8539	0.0171
Redund. steam gland condensers	1000	0.8938	0.0492	0.0019	0.0068	0.8432	0.0064
Redund. Low Press Heater Train 1	1000	0.8974	0.0562	0.0058	0.0104	0.8466	0.0098
Redund. Low Press Heater Train 2	1000	0.9021	0.0511	0.0035	0.0151	0.8511	0.0142
Redund. Feedpumps	1000	0.8851	0.0535	0.0035	~0	0.8350	~0
Redund. High Press Heater Train	1000	0.8933	0.0516	0.0030	0.0063	0.8427	0.0059
Fully redundant system	1000	0.9468	0.0442	0.0020	0.0598	0.8933	0.0565

Table 5.5 - Effects of redundancy on calculated mean cycle capacity factor

5.2.4.3 Increasing component mean time to shutdown

From the strategy section, it was explained that one of the approaches to achieving higher capacity factors is to design equipment to run longer, more reliably. This is analogous to an increase in the mean time to failure (MTTF) or mean time before required shutdown of equipment. An increase in the MTTF will allow plants to operate longer without shutdowns.

This section parametrically examines the value of unilateral percentage increases in the mean time to failure for all the components in the feedwater system only. This can also be thought of as increasing the time between required monitoring, inspection, calibration, maintenance, or repair. This analysis will generate expected increases in average plant capacity factors as a function of percentage increase in MTTF. Since the dollar value of a unit increase in capacity is known, the increase in MTTF can be translated directly into dollar savings.

Graph 5.4 shows that a 70% increase in feedwater component reliability translates roughly into a 2.5% increase in overall capacity factor. However, there is a saturation effect. After about a 70% increase in the mean time to failure, the slope changes significantly. This is due to the fact that the feedwater system is becoming very reliable, and there is not much more that can be gained between the current state and 100% reliability.

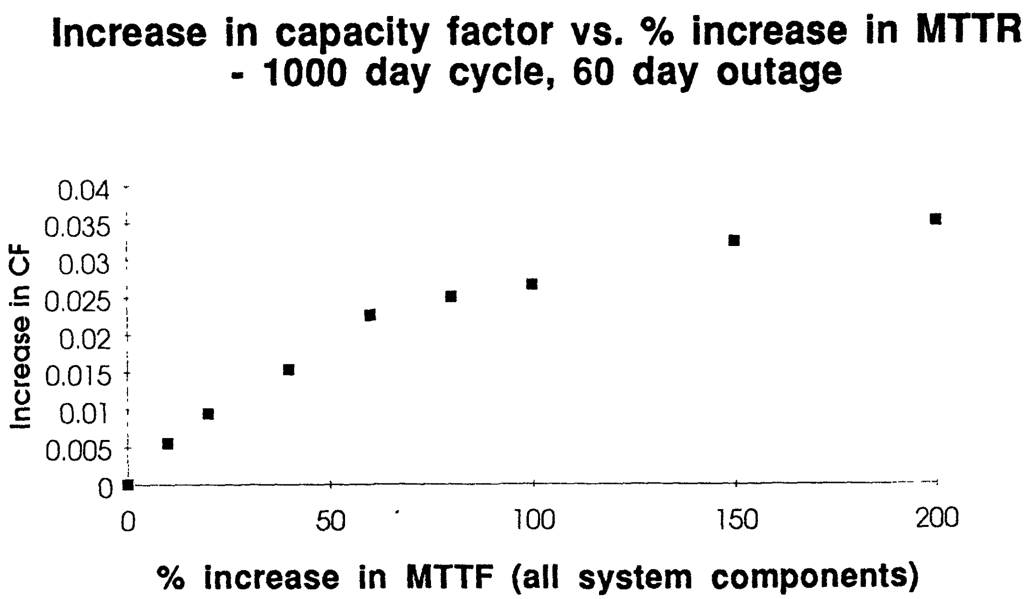

Figure 5.6

It should be mentioned here that there is one more strategy that could be used under this section. The approach taken was to improve the feedwater system reliability through increasing the mean time to failure. However, there is another way to increase the overall mean time to failure without changing any of the individual components—this is by simplification. According to [Seong, 1987], simplifying the feedwater system by eliminating two stages of low pressure heating, the gland seal steam condensers, and the steam jet air ejectors can actually save money by improving reliability. Seong argues that these components were eliminated on efficiency arguments, but reliability arguments were not properly taken into account. Therefore, a parallel approach to improving the overall feedwater system mean time to failure is simplification. This approach was not pursued further because Seong has already performed the analysis.

5.2.4.4 MTTR

The final strategy examined is decreasing the mean time to repair. Achieving a decrease in this parameter could correspond physically to an increase in maintenance staffing, an increase in spare parts inventory, better designed plants with more repair space, better designed equipment which facilitate repair, or an increase in equipment monitoring. Improved equipment monitoring can decrease the mean time to repair by giving the operator information in advance about the state of the equipment. It can inform the operator that the component is about to fail and can inform the operator as to what part in the component is about to fail, thus giving the operator time to prepare for the failure—order parts, train technicians.

As Figure 5.7 shows, improving the mean time to repair is a valuable asset for improving capacity factor. A 50% decrease in the mean time to repair for the feedwater system components can raise overall capacity factor by 3%.

Increase in capacity factor vs. % decrease in MTTR - 1000 day cycle, 60 day outage

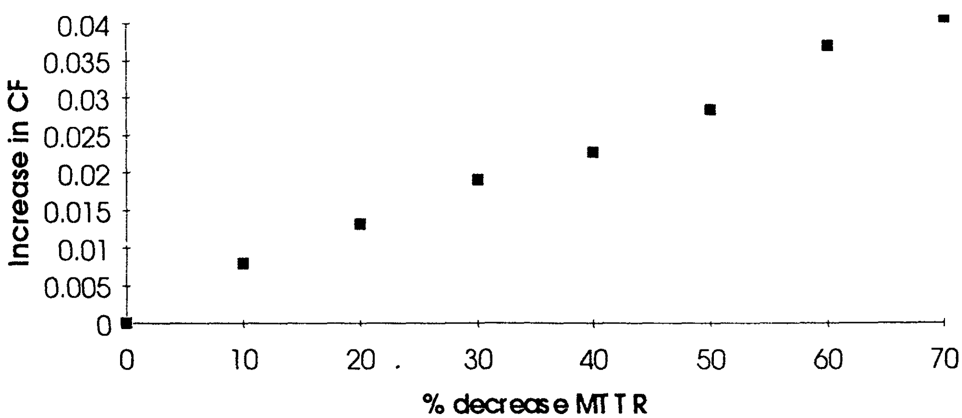

Figure 5.7

5.3 Summary

In this Chapter, a simplified model of a PWR nuclear power plant was developed, with the feedwater system modeled in more detail. The model's internal logic was modified slightly to generate availability data, and was compared to an analytical solution to the same problem. The results were in agreement, which suggests that the simplified monte-carlo model is a valid representation of the PWR model considered.

Next, the model was used to predict the effects of different strategies on plant capacity factor. The first strategy examined added redundancy. It was determined that the unavailability of passive heat exchangers affected capacity factor more significantly than the active components. Therefore, added redundancy may be justified in the steam jet air ejectors, in the turbine steam gland condensers, and in the low pressure and high pressure heaters. The benefit of adding redundancy to the condensate and feedwater pumps were inconclusive.

The next strategy analyzed was the value of achieving a unilateral increase of the mean time to failure (shutdown) of the feedwater system components. It was concluded that increasing the mean time to failure could improve capacity factor at an approximate ratio of 28% improvement in overall feedwater component reliability to 1% increase in capacity factor. However, no significant gains are achieved after a 70% increase in feedwater component reliability.

The final strategy analyzed was the value of achieving a unilateral decrease in the mean time to repair of the feedwater system components. It was concluded that decreasing the mean time to repair could improve capacity factor at an approximate ratio of 17% decrease in MTTR to 1% increase in capacity factor.

Chapter 6 - Summary/conclusions

6.1 Interviews
Interviews were conducted with over 50 industry representatives to solicit their opinions on the state of current nuclear plant designs and how plants could be designed to run for longer cycles and with higher capacity factors. Interviewees were comprised from a wide breadth of backgrounds, including utilities, the Nuclear Regulatory Commission, consulting companies, professional organizations, the vendors, and academia.

Ten general categories of comments emerged from these interviews:

1. Technical / Hardware Concerns
2. Regulatory / Institutional Framework
3. PRA in Design
4. Design Principles
5. Economic Pressures
6. Operation and Maintenance Practices
7. Material Condition
8. Cycle Length Pressures
9. Advanced Concepts
10. Safety
11. Plant Size

Each of these were elaborated upon in detail in Chapter 3.

6.2 Strategies
Three strategies were developed as an aid to redesigning plants for longer operating cycles and higher capacity factors. These strategies were designing to allow monitoring, inspection, calibration, maintenance and repair (MICMR) at higher modes of operation; to facilitate shorter times to complete MICMR; and to enhance the time between required MICMR. These strategies were applied to the steam generators as an example of how they can be used to help guide design goals. They were also applied to the analysis of the PWR feedwater system, which was modeled in greater detail.

6.3 PRA methods
A review of available probabilistic analysis methods was performed, with the goal of selecting a technique capable of realistically modeling the behavior of complex systems with interdependencies, external influences, and time dependent behavior. Methods surveyed were reliability block diagrams (RBDs), fault trees, event trees, Markov models, and simulation.

Simulation was selected because of its flexibility in modeling complex, realistic systems. However, this method is not without limitations. First, accuracy is limited by statistical variations. This can be overcome by performing more runs, which highlights simulation's second major limitation: long running times.

6.4 Cost benefit methods

The motivation for this research is economic. Nuclear power plants are experiencing competition worldwide. Plants with poor capacity factors and poor economic performance may not be able to compete. Therefore, the redesign of plant systems must be approached on a cost benefit basis. When considering a system modification, the benefits must exceed the costs.

6.4.1 Deterministic analysis

Traditionally, deterministic cost benefit analyses have been the method of choice in the industry. Point estimates are developed based on the best guesses of the benefits and costs of implementation. From these best estimates, cost decisions are made. However, this type of analysis does not address uncertainties in the expected benefits and expected costs. Consequently, decisions that look good from a deterministic analysis may sometimes be in error by not fully taking into account the risks.

6.4.2 Statistical analysis

Statistical cost benefit analysis methods can be used to specifically address uncertainties. This method gives the decision maker a much more complete picture of the risks and benefits associated with a decision. However, the techniques are mechanically difficult to use, and a much more complete knowledge of the uncertainties is required. But if the uncertainties associated with a decision are important and desired, this can be a powerful decision making technique.

6.5 Plant model

A simplified plant model was constructed using the Simscript II.5 simulation language. The model incorporated simplified representations of major plant systems with a more detailed representation of the feedwater system. The purpose of this chapter was to apply the strategies of Chapter 2 to the simplified plant model. The simulation model was used to analyze the effects of the strategies on capacity factor. The value of simulation was demonstrated by analyzing plant systems before any costly design decisions are made.

6.5.1 Data

Much of the feedwater component data used are generic industry data for generic pumps and heat exchangers. Global lumped reliability values were chosen to be consistent with references, industry experience, and the industry interviews of Chapter 3. For a generic analysis, this data is sufficient. However, for a plant specific analysis, data applicable to particular component models is more accurate and is necessary. If component specific data are not used, the uncertainty in the reliability data will be greater than the expected capacity factor improvements. Under these conditions, no conclusions can be made.

6.5.2 Validation

The plant model's logic was simplified slightly to allow comparison with an analytical solution derived using reliability block diagram methods. This analysis showed that the results obtained from simulation agreed well with the analytic solution. This should be taken as an indication that the simulation model is valid for this configuration and for future perturbation calculations; however, proof of validity may be impossible.

6.5.3 Conclusions

The base model developed was used to analyze several different perturbations.

6.5.3.1 Cycle length

The base design was run to determine average expected plant capacity factor as a function of cycle length. It was seen that for short cycle lengths, the operational capacity factor (OCF) was very high. However, the OCF approached its asymptote after about 500 days. It was also seen that the overall capacity factor (CF) - for a given 60 day outage length - increased rapidly as cycle length was increased, but again approached an asymptote.

6.5.3.2 Redundancy

The effects of adding redundancy were analyzed. It was seen that components with long repair times (but with lower failure rates) tended to dominate capacity factor loss. This indicates that designing for shorter repair times may be a more effective strategy than designing for higher reliability. It was predicted that adding a redundant fourth train to the feedwater system could increase capacity by about 5.5% for a 1000 day cycle with a 60 day refueling outage.

6.5.3.3 Mean time to failure

The effects of designing for increased feedwater component reliability were analyzed. It was seen that increasing component reliability increased the feedwater system reliability at a rate of 2% capacity per 50% increase in every feedwater component's reliability. However, after about a 70% increase in component reliability (~2.5% capacity factor), the capacity factor gain became much less pronounced.

6.5.3.4 Mean time to repair

The effects of designing for shorter repair times for feedwater components were analyzed. It was seen that decreasing the mean time to repair by 50% for every feedwater component increases capacity factor by approximately 3%. It can be concluded that there is significant value to decreasing repair times.

6.6 Future work

This research identified many possible directions for future research that were beyond the scope of this thesis. The following sections contain the areas where future research can be initiated.

6.6.1 Reliability analysis

6.6.1.1 Better component reliability and repair data

There is a need to obtain more accurate, realistic data to improve analysis results and conclusions. For plant specific conclusions, plant equipment operating data should be analyzed. For more general data, component vendors should be consulted to obtain realistic component reliability data. In both cases, a firm physical understanding of the components, their failure mechanisms, and their repair requirements should be acquired.

6.6.1.2 Improvements for availability analysis model

The model completed to date is significantly simplified relative to actual operating plants. Several areas have been identified to improve model accuracy and treatment.

6.6.1.2.1 High priority items

- Model the plant in greater detail to better represent actual plant operation.
- Explicitly treat dependencies. This was one of the bases for adopting the monte-carlo method.
- Model shutdown conditions. Currently, components are treated as in active operation throughout the cycle. A better representation would be to model failure mechanisms for components in shutdown conditions. This includes modeling demand failures and standby failures.

6.6.1.2.2 Lower priority items

- The component "burn-in" period may need to be modeled if burn-in failures are determined to contribute significantly to capacity loss.
- The component "wear-out" period may need to be modeled if equipment experiences increased failure rates due to less frequent maintenance, which is expected for longer cycles.
- The code structure is simple and adequate for current analyses. However, using queuing can significantly improve code execution speed, which may be important for more complex, future models.

6.6.1.3 Alternate techniques

Risk increase importance measures, availability loss importance measures, and as yet hypothesized importance measures may be useful in the optimization of maintenance resource allocation. They may also yield insights into better system designs.

6.6.1.4 Alternate strategy

Strategies examined to date were (1) performing critical activities at higher modes of operation, (2) increasing component reliability, and (3) decreasing repair times. A fourth strategy not yet examined is the effects of simplification on availability. This strategy should be pursued in future research, if it has not already been fully addressed by previous research.

6.6.2 Engineering modifications / redesign

6.6.2.1 Identifying engineering limitations worth further analysis

6.6.2.1.1 Identifying poor system performance

- Contact NRC, Office for Analysis and Evaluation of Operational Data (AEOD). They do industry trending of system performance. Data may be available. (May only be safety systems)
- Review forced outage causes for indications of design weaknesses.
- Review of operating experience for plants on a 2 year cycle. Find the limitations that cause them to shut down.

6.6.2.1.2 Inspection and surveillance requirements

A detailed review of current inspection and surveillance criteria should be performed to identify limitations in current designs. Surveillance interval extensions has been addressed by EPRI and the NRC Generic Letter 91-04. Examining the Standard Technical Specifications and the System 80+ Technical Specifications may yield additional insights. The ASME testing codes must be checked for safety valve inspection / maintenance requirements.

6.6.2.2 Components specific analyses

Several candidate systems for redesign were identified in Chapters 2 and 3. The following candidates have already been analyzed to some extent, and may be worth further analysis.

6.6.2.2.1 Reactor coolant pumps

PWR_#9 performed an analysis confirming that a spare reactor coolant pump motor for quick change-out was justified on a cost savings basis. A similar analysis could be used to benchmark the cost benefit analysis methods listed in Chapter 4.

Additional engineering analysis should be performed to determine why there exists a disparity between the consequences of loss of reactor coolant pump seal cooling between different pump vendors. Loss of seal cooling may result in a seal LOCA, which is significant from a safety perspective. Therefore, more analysis may be justified.

6.6.2.2.2 Steam generators

A feasibility study of the steam generator redesign options of Section 2.4 should be performed. This would be valuable research, because the steam generators are considered by many to be the "weak link" in current and future PWR designs. The economic risk associated with poor steam generator performance is enormous.

6.6.2.3 Predictive monitoring and maintenance

Predictive monitoring and maintenance techniques are extremely valuable in industry. They will be more valuable to plants intending to operate under longer fuel cycles, because prescriptive shutdown periodicities may be too restrictive for these longer cycles. The following is an initial list of monitoring techniques identified in interviews. This list should be completed, and fully explored. These techniques may be valuable for engineering solutions to problematic components.

- vibration monitoring
- electrical signatures
- thermography
- lube oil testing
- hydraulic testing
- leak monitoring
- battery testing
- performance monitoring

Inspection, calibration and repair techniques should also be surveyed for use in engineering analyses.

6.6.2.4 Online monitoring and testing capabilities

Online monitoring and testing capabilities may become necessary for longer fuel cycles to verify operability of important components. Capabilities such as online monitoring of steam generator tube condition would be invaluable. The System 80^+ FSAR should be reviewed to determine the "state of the art" monitoring and testing capabilities.

6.6.3 Long-lived core design

Fuel cycle calculations are currently underway. Areas of interest are enrichment requirements, fuel cycle economics, and reactivity hold-down. More subtle considerations in the economic analysis which should also be explored are reduced refueling workforce (even with a required mid-cycle outage), and the effects of cycle length on refueling outage duration.

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Appendix A: Simulation program listing in Simscript Language for base configuration

```
PREAMBLE
  ''The purpose of this program is to model a PWR nuclear
  ''power plant in simplified block form with a detialed description of the
  ''feedwater system.
  ''See diagram for component names and better system description.
  Processes include FLOW
  Resources include CONDP, SJAE, GLAND.COND, DCOOL, LPH1, LPH2, LPH3, LPH4,
    LPH5, FEEDP, HPH, STEAM.GEN, TURB.GEN, COND, RCP, REACT, and PRESS
  ''.FT means .FAILURE.TIME; .RT means REPAIR.TIME;
  ''.CAP means CAPACITY; and .AV means AVAILABILITY
  Every CONDP has a CONDP.FT, a CONDP.RT, a CONDP.AV, and a CONDP.CAP
  Every SJAE has a SJAE.FT, a SJAE.RT, a SJAE.AV, and a SJAE.CAP
  Every GLAND.COND has a GLAND.COND.FT, a GLAND.COND.RT, a GLAND.COND.AV,
        and a GLAND.COND.CAP
  Every DCOOL has a DCOOL.FT, a DCOOL.RT, a DCOOL.AV, and a DCOOL.CAP
  Every LPH1 has a LPH1.FT, a LPH1.RT, a LPH1.AV, and a LPH1.CAP
  Every LPH2 has a LPH2.FT, a LPH2.RT, a LPH2.AV, and a LPH2.CAP
  Every LPH3 has a LPH3.FT, a LPH3.RT, a LPH3.AV, and a LPH3.CAP
  Every LPH4 has a LPH4.FT, a LPH4.RT, a LPH4.AV, and a LPH4.CAP
  Every LPH5 has a LPH5.FT, a LPH5.RT, a LPH5.AV, and a LPH5.CAP
  Every FEEDP has a FEEDP.FT, a FEEDP.RT, a FEEDP.AV, and a FEEDP.CAP
  Every HPH has a HPH.FT, a HPH.RT, a HPH.AV, and a HPH.CAP
  Every STEAM.GEN has a STEAM.GEN.FT, a STEAM.GEN.RT, a STEAM.GEN.AV,
        and a STEAM.GEN.CAP
  Every TURB.GEN has a TURB.GEN.FT, a TURB.GEN.RT, a TURB.GEN.AV,
        and a TURB.GEN.CAP
  Every COND has a COND.FT, a COND.RT, a COND.AV, and a COND.CAP
  Every RCP has a RCP.FT, a RCP.RT, a RCP.AV, and a RCP.CAP
  Every REACT has a REACT.FT, a REACT.RT, a REACT.AV, and a REACT.CAP
  Every PRESS has a PRESS.FT, a PRESS.RT, a PRESS.AV, and a PRESS.CAP
    Define CONDP.FT, SJAE.FT, GLAND.COND.FT, DCOOL.FT, LPH1.FT, LPH2.FT,
      LPH3.FT, LPH4.FT, LPH5.FT, FEEDP.FT, HPH.FT, STEAM.GEN.FT, TURB.GEN.FT,
      COND.FT, RCP.FT, REACT.FT, and PRESS.FT as real variables
    Define CONDP.RT, SJAE.RT, GLAND.COND.RT, DCOOL.RT, LPH1.RT, LPH2.RT,
      LPH3.RT, LPH4.RT, LPH5.RT, FEEDP.RT, HPH.RT, STEAM.GEN.RT, TURB.GEN.RT,
      COND.RT, RCP.RT, REACT.RT, and PRESS.RT as real variables
    Define CONDP.CAP, SJAE.CAP, GLAND.COND.CAP, DCOOL.CAP, LPH1.CAP, LPH2.CAP,
      LPH3.CAP, LPH4.CAP, LPH5.CAP, FEEDP.CAP, HPH.CAP, STEAM.GEN.CAP,
      TURB.GEN.CAP, COND.CAP, RCP.CAP, REACT.CAP, and PRESS.CAP
      as real variables
    Define CONDP.AV, SJAE.AV, GLAND.COND.AV, DCOOL.AV, LPH1.AV, LPH2.AV,
      LPH3.AV, LPH4.AV, LPH5.AV, FEEDP.AV, HPH.AV, STEAM.GEN.AV, TURB.GEN.AV,
      COND.AV, RCP.AV, REACT.AV, and PRESS.AV as real variables

  Define RESET as a text variable
  Define EFPD and AVAIL as 1-dimensional, real arrays
  Define NUM.CYCLES and NUM.POINTS as integer variables
  Define TOTAL.EFPD, CYCLE.LENGTH and AVERAGE.EFPD as real variables
  Define CONDENSATE.CAP, STEAM.JET.CAP, GLAND.CONDENSER.CAP, LPHEAT1.CAP,
    LPHEAT2.CAP,FEEDPUMPS.CAP,HPHEAT.CAP,STEAM.GENERATOR.CAP,
    TURBINE.GENERATOR.CAP,CONDENSER.CAP, REACTOR.PUMP.CAP, REACTOR.CAP,
    PRESSURIZER.CAP, and FEEDWATER.CAP as real variables
  Define CAPACITY.FACT, TIME.INCREMENT and AVAIL.AVERAGE as real variables

  Tally MEAN.CAPACITY.FACT as the mean of CAPACITY.FACT
  Tally SD.CAPACITY.FACT as the std.dev of CAPACITY.FACT
  Tally SD.MEAN.CAPACITY.FACT as the std.dev of AVAIL.AVERAGE

  Tally CONDENSATE.AV as the mean of CONDENSATE.CAP
  Tally STEAM.JET.AV as the mean of STEAM.JET.CAP
  Tally GLAND.CONDENSER.AV as the mean of GLAND.CONDENSER.CAP
  Tally LPHEAT1.AV as the mean of LPHEAT1.CAP
  Tally LPHEAT2.AV as the mean of LPHEAT2.CAP
  Tally FEEDPUMPS.AV as the mean of FEEDPUMPS.CAP
  Tally HPHEAT.AV as the mean of HPHEAT.CAP
  Tally CONDENSER.AV as the mean of CONDENSER.CAP
```

```
  Tally REACTOR.PUMP.AV as the mean of REACTOR.PUMP.CAP
  Tally PRESSURIZER.AV as the mean of PRESSURIZER.CAP
  Tally TURBINE.GENERATOR.AV as the mean of TURBINE.GENERATOR.CAP
  Tally REACTOR.AV as the mean of REACTOR.CAP
  Tally STEAM.GENERATOR.AV as the mean of STEAM.GENERATOR.CAP
  Tally FEEDWATER.AV as the mean of FEEDWATER.CAP

END
MAIN
  Activate a FLOW now
  Start simulation
  Open 8 for output, file name = "OUTPUT"
  Use 8 for output
  Begin report

  Print 20 lines with CYCLE.LENGTH, NUM.CYCLES, TOTAL.EFPD, AVERAGE.EFPD,
    FEEDWATER.AV, CONDENSATE.AV, STEAM.JET.AV, GLAND.CONDENSER.AV, LPHEAT1.AV,
    LPHEAT2.AV, FEEDPUMPS.AV, HPHEAT.AV, STEAM.GENERATOR.AV,
    TURBINE.GENERATOR.AV, CONDENSER.AV, REACTOR.PUMP.AV, REACTOR.AV,
    PRESSURIZER.AV thus
    Length of cycle ******
    Number of EFPDs in *** cycles was       ****.*
    Average number of EFPDs per cycle was   ****.*

    Individual system availability data
    -----------------------------------------------------------
      Feedwater System                Availability    **.****
        Condensate Pump Train         Availability        **.****
        Steam Jet Air Ejector Train Availability          **.****
        Turbine Gland Condenser       Availability        **.****
        Low Pressure Heater Train 1 Availability          **.****
        Low Pressure Heater Train 2 Availability          **.****
        Feedwater Pump Train          Availability        **.****
        High Pressure Heater Train    Availability        **.****
      Steam Generator                 Availability    **.****
      Turbine Generator               Availability    **.****
      Condensor                       Availability    **.****
      Reactor Coolant Pump            Availability    **.****
      Reactor                         Availability    **.****
      Pressurizer                     Availability    **.****

  Skip 2 lines

  For Z = 1 to NUM.CYCLES
    DO
      Let CAPACITY.FACT = EFPD(Z)/CYCLE.LENGTH
    LOOP
  Print 2 lines thus
  Overall plant availability data
  ______________________________________________________________
  Print 3 lines with MEAN.CAPACITY.FACT, SD.MEAN.CAPACITY.FACT,
  and SD.CAPACITY.FACT thus
    Mean Plant Availability                             *****.*****
    Standard Deviation of Mean Plant Availability       *****.*****
    Standard Deviation of Plant Availability            *****.*****

  Print 2 lines thus
  Time point    A(t)
  -------------------
  For Y = 1 to NUM.POINTS
    Do
      Let TIME = TIME + TIME.INCREMENT
      Print 1 line with TIME and AVAIL(Y)/NUM.CYCLES thus
  ******        **.*******
    Loop

  End

END
Process FLOW
  Define TIME.TO.MEASURE as a real variable
```

```
  Define POINT as an integer variable

  Let NUM.CYCLES = 1000
  Let CYCLE.LENGTH = 1000
  Let NUM.POINTS = 100
  Reserve EFPD(*) as NUM.CYCLES
  Reserve AVAIL(*) as NUM.POINTS
  Let TIME.INCREMENT = Int.f(CYCLE.LENGTH/NUM.POINTS)

  For I = 1 to NUM.CYCLES
    Do
      Let RESET = "YES"
      Let POINT = 1
      Let time.v = 0
      Let TIME.TO.MEASURE = TIME.INCREMENT
      Until (time.v>=CYCLE.LENGTH)
        Do

          Call FEEDWATER                   ''Feedwater System
          Call STEAM.GENERATOR             ''Steam Generators
          Call TURBINE.GENERATOR           ''Turbine Generator
          Call CONDENSER                   ''Condenser
          Call REACTOR.PUMP                ''Reactor Coolant Pump
          Call REACTOR                     ''Reactor
          Call PRESSURIZER                 ''Pressurizer

          Wait 1 day
          Let RESET = "NO"
          Let CAPACITY = Min.f(FEEDWATER.CAP,STEAM.GENERATOR.CAP,
                 TURBINE.GENERATOR.CAP,CONDENSER.CAP,REACTOR.PUMP.CAP,
                 REACTOR.CAP,PRESSURIZER.CAP)

          If time.v >= TIME.TO.MEASURE
            Let AVAIL(POINT) = AVAIL(POINT) + CAPACITY
            Let POINT = POINT+1
            Let TIME.TO.MEASURE = TIME.TO.MEASURE + TIME.INCREMENT
          Always
          Let EFPD(I) = EFPD(I) + CAPACITY
        Loop

      Let TOTAL.EFPD = TOTAL.EFPD + EFPD(I)
      Let AVAIL.AVERAGE = ((I-1)*AVAIL.AVERAGE + EFPD(I)/CYCLE.LENGTH)/I
    Loop

  Let AVERAGE.EFPD = TOTAL.EFPD / NUM.CYCLES
END
Routine FEEDWATER
  Call CONDENSATE              ''Feedwater System
  Call GLAND.CONDENSER         ''Feedwater System
  Call STEAM.JET               ''Feedwater System
  Call LPHEAT1                 ''Feedwater System
  Call LPHEAT2                 ''Feedwater System
  Call FEEDPUMP                ''Feedwater System
  Call HPHEAT                  ''Feedwater System
  Let FEEDWATER.CAP=Min.f(1,CONDENSATE.CAP,GLAND.CONDENSER.CAP,STEAM.JET.CAP,
                 LPHEAT1.CAP,LPHEAT2.CAP,FEEDPUMPS.CAP,HPHEAT.CAP)

END
Routine CONDENSATE
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTFC, MTTRA, MTTRB, MTTRC, SDA, SDB, and SDC
    as real variables
  Let MTTFA = 1000
  Let MTTFB = 1000
  Let MTTFC = 1000
  Let MTTRA = 2
  Let MTTRB = 2
  Let MTTRC = 2
  Let SDA = 2
  Let SDB = 2
  Let SDC = 2
```

```
  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every CONDP
    Create every CONDP(3)
    U.CONDP(A) = 1
    U.CONDP(B) = 1
    U.CONDP(C) = 1
    Let CONDP.CAP(A) = .5
    Let CONDP.CAP(B) = .5
    Let CONDP.CAP(C) = .5
    Let CONDP.FT(A) = Exponential.f(MTTFA,1)
    Let CONDP.FT(B) = Exponential.f(MTTFB,2)
    Let CONDP.FT(C) = Exponential.f(MTTFC,3)
    Let CONDP.RT(A) = Log.Normal.f(MTTRA,SDA,4)
    Let CONDP.RT(B) = Log.Normal.f(MTTRB,SDB,5)
    Let CONDP.RT(C) = Log.Normal.f(MTTRC,SDC,6)
  Always

  If time.v >= CONDP.FT(A)
    Let CONDP.CAP(A) = 0.0
    If time.v >= (CONDP.FT(A) + CONDP.RT(A))
      Let CONDP.CAP(A) = 0.5
      Let CONDP.FT(A) = CONDP.FT(A)+CONDP.RT(A)+Exponential.f(MTTFA,1)
      Let CONDP.RT(A) = Log.Normal.f(MTTRA,SDA,4)
    Always
  Always

  If time.v >= CONDP.FT(B)
    Let CONDP.CAP(B) = 0.0
    If time.v >= (CONDP.FT(B) + CONDP.RT(B))
      Let CONDP.CAP(B) = 0.5
      Let CONDP.FT(B) = CONDP.FT(B)+CONDP.RT(B)+Exponential.f(MTTFB,2)
      Let CONDP.RT(B) = Log.Normal.f(MTTRB,SDB,5)
    Always
  Always

  If time.v >= CONDP.FT(C)
    Let CONDP.CAP(C) = 0.0
    If time.v >= (CONDP.FT(C) + CONDP.RT(C))
      Let CONDP.CAP(C) = 0.5
      Let CONDP.FT(C) = CONDP.FT(C)+CONDP.RT(C)+Exponential.f(MTTFC,3)
      Let CONDP.RT(C) = Log.Normal.f(MTTRC,SDC,6)
    Always
  Always

  Let CAPACITY = CONDP.CAP(A)+CONDP.CAP(B)+CONDP.CAP(C)
  Let CONDENSATE.CAP = Min.f(CAPACITY,1)
END
Routine STEAM.JET
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTFC, MTTRA, MTTRB, MTTRC, SDA, SDB, and SDC
    as real variables

  Let MTTFA = 1000
  Let MTTFB = 1000
  Let MTTFC = 1000
  Let MTTRA = 20
  Let MTTRB = 20
  Let MTTRC = 20
  Let SDA = 20
  Let SDB = 20
  Let SDC = 20
  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every SJAE
```

```
    Create every SJAE(3)
    U.SJAE(A) = 1
    U.SJAE(B) = 1
    U.SJAE(C) = 1
    Let SJAE.CAP(A) = 0.334
    Let SJAE.CAP(B) = 0.334
    Let SJAE.CAP(C) = 0.334
    Let SJAE.FT(A) = Exponential.f(MTTFA,7)
    Let SJAE.FT(B) = Exponential.f(MTTFB,8)
    Let SJAE.FT(C) = Exponential.f(MTTFC,9)
    Let SJAE.RT(A) = Log.Normal.f(MTTRA,SDA,1)
    Let SJAE.RT(B) = Log.Normal.f(MTTRB,SDB,2)
    Let SJAE.RT(C) = Log.Normal.f(MTTRC,SDC,3)
  Always

  If time.v >= SJAE.FT(A)
    Let SJAE.CAP(A) = 0.0
    If time.v >= (SJAE.FT(A) + SJAE.RT(A))
      Let SJAE.CAP(A) = 0.334
      Let SJAE.FT(A) = SJAE.FT(A)+SJAE.RT(A)+Exponential.f(MTTFA,7)
      Let SJAE.RT(A) = Log.Normal.f(MTTRA,SDA,1)
    Always
  Always

  If time.v >= SJAE.FT(B)
    Let SJAE.CAP(B) = 0.0
    If time.v >= (SJAE.FT(B) + SJAE.RT(B))
      Let SJAE.CAP(B) = 0.334
      Let SJAE.FT(B) = SJAE.FT(B)+SJAE.RT(B)+Exponential.f(MTTFB,8)
      Let SJAE.RT(B) = Log.Normal.f(MTTRB,SDB,2)
    Always
  Always

  If time.v >= SJAE.FT(C)
    Let SJAE.CAP(C) = 0.0
    If time.v >= (SJAE.FT(C) + SJAE.RT(C))
      Let SJAE.CAP(C) = 0.334
      Let SJAE.FT(C) = SJAE.FT(C)+SJAE.RT(C)+Exponential.f(MTTFC,9)
      Let SJAE.RT(C) = Log.Normal.f(MTTRC,SDC,3)
    Always
  Always

  Let CAPACITY = SJAE.CAP(A)+SJAE.CAP(B)+SJAE.CAP(C)
  Let STEAM.JET.CAP = Min.f(CAPACITY,1)
END
Routine GLAND.CONDENSER

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 30
  Let SD = 30
  Let A = 1

  If RESET = "YES"
    Destroy every GLAND.COND
    Create every GLAND.COND(1)
    U.GLAND.COND(A) = 1
    Let GLAND.COND.CAP(A) = 1.0
    Let GLAND.COND.FT(A) = Exponential.f(MTTF,8)
    Let GLAND.COND.RT(A) = Log.Normal.f(MTTR,SD,9)
  Always

  If time.v >= GLAND.COND.FT(A)
    Let GLAND.COND.CAP(A) = 0.0
    If time.v >= (GLAND.COND.FT(A) + GLAND.COND.RT(A))
      Let GLAND.COND.CAP(A) = 1.0
      Let GLAND.COND.FT(A) = GLAND.COND.FT(A)+GLAND.COND.RT(A)+
          Exponential.f(MTTF,8)
      Let GLAND.COND.RT(A) = Log.Normal.f(MTTR,SD,9)
```

```
    Always
  Always

  Let CAPACITY = GLAND.COND.CAP(A)
  Let GLAND.CONDENSER.CAP = Min.f(CAPACITY,1)
END

Routine LPHEAT1
  Define CAPACITY as a real variable
  Define MTTF_DCA, MTTF_H1A, MTTF_H2A, MTTF_DCB, MTTF_H1B, MTTF_H2B,
    MTTF_DCC, MTTF_H1C, MTTF_H2C, MTTR_DCA, MTTR_H1A, MTTR_H2A,
    MTTR_DCB, MTTR_H1B, MTTR_H2B, MTTR_DCC, MTTR_H1C, MTTR_H2C,
    SD_DCA, SD_H1A, SD_H2A, SD_DCB, SD_H1B, SD_H2B,SD_DCC, SD_H1C, and
    SD_H2C as real variables

  Let MTTF_DCA = 5000
  Let MTTF_DCB = 5000
  Let MTTF_DCC = 5000
  Let MTTR_DCA = 30
  Let MTTR_DCB = 30
  Let MTTR_DCC = 30
  Let SD_DCA = 30
  Let SD_DCB = 30
  Let SD_DCC = 30

  Let MTTF_H1A = 5000
  Let MTTF_H1B = 5000
  Let MTTF_H1C = 5000
  Let MTTR_H1A = 30
  Let MTTR_H1B = 30
  Let MTTR_H1C = 30
  Let SD_H1A = 30
  Let SD_H1B = 30
  Let SD_H1C = 30

  Let MTTF_H2A = 5000
  Let MTTF_H2B = 5000
  Let MTTF_H2C = 5000
  Let MTTR_H2A = 30
  Let MTTR_H2B = 30
  Let MTTR_H2C = 30
  Let SD_H2A = 30
  Let SD_H2B = 30
  Let SD_H2C = 30

  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every DCOOL
    Create every DCOOL(3)
    U.DCOOL(A) = 1
    U.DCOOL(B) = 1
    U.DCOOL(C) = 1
    Let DCOOL.CAP(A) = 0.334
    Let DCOOL.CAP(B) = 0.334
    Let DCOOL.CAP(C) = 0.334
    Let DCOOL.FT(A) = Exponential.f(MTTF_DCA,4)
    Let DCOOL.FT(B) = Exponential.f(MTTF_DCB,5)
    Let DCOOL.FT(C) = Exponential.f(MTTF_DCC,6)
    Let DCOOL.RT(A) = Log.Normal.f(MTTR_DCA,SD_DCA,7)
    Let DCOOL.RT(B) = Log.Normal.f(MTTR_DCB,SD_DCB,8)
    Let DCOOL.RT(C) = Log.Normal.f(MTTR_DCC,SD_DCC,9)

    Destroy every LPH1
    Create every LPH1(3)
    U.LPH1(A) = 1
    U.LPH1(B) = 1
    U.LPH1(C) = 1
    Let LPH1.CAP(A) = 0.334
```

```
  Let LPH1.CAP(B) = 0.334
  Let LPH1.CAP(C) = 0.334
  Let LPH1.FT(A) = Exponential.f(MTTF_H1A,1)
  Let LPH1.FT(B) = Exponential.f(MTTF_H1B,2)
  Let LPH1.FT(C) = Exponential.f(MTTF_H1C,3)
  Let LPH1.RT(A) = Log.Normal.f(MTTR_H1A,SD_H1A,4)
  Let LPH1.RT(B) = Log.Normal.f(MTTR_H1B,SD_H1B,5)
  Let LPH1.RT(C) = Log.Normal.f(MTTR_H1C,SD_H1C,6)

  Destroy every LPH2
  Create every LPH2(3)
  U.LPH2(A) = 1
  U.LPH2(B) = 1
  U.LPH2(C) = 1
  Let LPH2.CAP(A) = 0.334
  Let LPH2.CAP(B) = 0.334
  Let LPH2.CAP(C) = 0.334
  Let LPH2.FT(A) = Exponential.f(MTTF_H2A,7)
  Let LPH2.FT(B) = Exponential.f(MTTF_H2B,8)
  Let LPH2.FT(C) = Exponential.f(MTTF_H2C,9)
  Let LPH2.RT(A) = Log.Normal.f(MTTR_H2A,SD_H2A,1)
  Let LPH2.RT(B) = Log.Normal.f(MTTR_H2B,SD_H2B,2)
  Let LPH2.RT(C) = Log.Normal.f(MTTR_H2C,SD_H2C,3)
Always

If time.v>=DCOOL.FT(A) or time.v>=LPH1.FT(A) or time.v>=LPH2.FT(A)
  If time.v >= DCOOL.FT(A)
    Let DCOOL.CAP(A) = 0
    If time.v >= (DCOOL.FT(A) + DCOOL.RT(A))
      Let DCOOL.CAP(A) = 0.334
      Let DCOOL.FT(A) = DCOOL.FT(A)+DCOOL.RT(A)+Exponential.f(MTTF_DCA,4)
      Let DCOOL.RT(A) = Log.Normal.f(MTTR_DCA,SD_DCA,7)
    Always
  Always
  If time.v >= LPH1.FT(A)
    Let LPH1.CAP(A) = 0
    If time.v >= (LPH1.FT(A) + LPH1.RT(A))
      Let LPH1.CAP(A) = 0.334
      Let LPH1.FT(A) = LPH1.FT(A)+LPH1.RT(A)+Exponential.f(MTTF_H1A,1)
      Let LPH1.RT(A) = Log.Normal.f(MTTR_H1A,SD_H1A,4)
    Always
  Always
  If time.v >= LPH2.FT(A)
    Let LPH2.CAP(A) = 0
    If time.v >= (LPH2.FT(A) + LPH2.RT(A))
      Let LPH2.CAP(A) = 0.334
      Let LPH2.FT(A) = LPH2.FT(A)+LPH2.RT(A)+Exponential.f(MTTF_H2A,7)
      Let LPH2.RT(A) = Log.Normal.f(MTTR_H2A,SD_H2A,1)
    Always
  Always
Always

If time.v>=DCOOL.FT(B) or time.v>=LPH1.FT(B) or time.v>=LPH2.FT(B)
  If time.v >= DCOOL.FT(B)
    Let DCOOL.CAP(B) = 0
    If time.v >= (DCOOL.FT(B) + DCOOL.RT(B))
      Let DCOOL.CAP(B) = 0.334
      Let DCOOL.FT(B) = DCOOL.FT(B)+DCOOL.RT(B)+Exponential.f(MTTF_DCB,4)
      Let DCOOL.RT(B) = Log.Normal.f(MTTR_DCB,SD_DCB,7)
    Always
  Always
  If time.v >= LPH1.FT(B)
    Let LPH1.CAP(B) = 0
    If time.v >= (LPH1.FT(B) + LPH1.RT(B))
      Let LPH1.CAP(B) = 0.334
      Let LPH1.FT(B) = LPH1.FT(B)+LPH1.RT(B)+Exponential.f(MTTF_H1B,1)
      Let LPH1.RT(B) = Log.Normal.f(MTTR_H1B,SD_H1B,4)
    Always
  Always
  If time.v >= LPH2.FT(B)
    Let LPH2.CAP(B) = 0
```

```
      If time.v >= (LPH2.FT(B) + LPH2.RT(B))
        Let LPH2.CAP(B) = 0.334
        Let LPH2.FT(B) = LPH2.FT(B)+LPH2.RT(B)+Exponential.f(MTTF_H2B,7)
        Let LPH2.RT(B) = Log.Normal.f(MTTR_H2B,SD_H2B,1)
      Always
    Always
  Always

  If time.v>=DCOOL.FT(C) or time.v>=LPH1.FT(C) or time.v>=LPH2.FT(C)
    If time.v >= DCOOL.FT(C)
      Let DCOOL.CAP(C) = 0
      If time.v >= (DCOOL.FT(C) + DCOOL.RT(C))
        Let DCOOL.CAP(C) = 0.334
        Let DCOOL.FT(C) = DCOOL.FT(C)+DCOOL.RT(C)+Exponential.f(MTTF_DCC,4)
        Let DCOOL.RT(C) = Log.Normal.f(MTTR_DCC,SD_DCC,7)
      Always
    Always
    If time.v >= LPH1.FT(C)
      Let LPH1.CAP(C) = 0
      If time.v >= (LPH1.FT(C) + LPH1.RT(C))
        Let LPH1.CAP(C) = 0.334
        Let LPH1.FT(C) = LPH1.FT(C)+LPH1.RT(C)+Exponential.f(MTTF_H1C,1)
        Let LPH1.RT(C) = Log.Normal.f(MTTR_H1C,SD_H1C,4)
      Always
    Always
    If time.v >= LPH2.FT(C)
      Let LPH2.CAP(C) = 0
      If time.v >= (LPH2.FT(C) + LPH2.RT(C))
        Let LPH2.CAP(C) = 0.334
        Let LPH2.FT(C) = LPH2.FT(C)+LPH2.RT(C)+Exponential.f(MTTF_H2C,7)
        Let LPH2.RT(C) = Log.Normal.f(MTTR_H2C,SD_H2C,1)
      Always
    Always
  Always

  Let TRAIN1.CAP = Min.f(DCOOL.CAP(A),LPH1.CAP(A),LPH2.CAP(A))
  Let TRAIN2.CAP = Min.f(DCOOL.CAP(B),LPH1.CAP(B),LPH2.CAP(B))
  Let TRAIN3.CAP = Min.f(DCOOL.CAP(C),LPH1.CAP(C),LPH2.CAP(C))

  Let CAPACITY = TRAIN1.CAP + TRAIN2.CAP + TRAIN3.CAP
  Let LPHEAT1.CAP = Min.f(CAPACITY,1)
END
Routine LPHEAT2
  Define CAPACITY as a real variable
  Define MTTF_H3A, MTTF_H4A, MTTF_H5A, MTTF_H3B, MTTF_H4B, MTTF_H5B,
    MTTF_H3C, MTTF_H4C, MTTF_H5C, MTTR_H3A, MTTR_H4A, MTTR_H5A,
    MTTR_H3B, MTTR_H4B, MTTR_H5B, MTTR_H3C, MTTR_H4C, MTTR_H5C,
    SD_H3A, SD_H4A, SD_H5A, SD_H3B, SD_H4B, SD_H5B, SD_H3C, SD_H4C, and
    SD_H5C as real variables

  Let MTTF_H3A = 5000
  Let MTTF_H3B = 5000
  Let MTTF_H3C = 5000
  Let MTTR_H3A = 30
  Let MTTR_H3B = 30
  Let MTTR_H3C = 30
  Let SD_H3A = 30
  Let SD_H3B = 30
  Let SD_H3C = 30

  Let MTTF_H4A = 5000
  Let MTTF_H4B = 5000
  Let MTTF_H4C = 5000
  Let MTTR_H4A = 30
  Let MTTR_H4B = 30
  Let MTTR_H4C = 30
  Let SD_H4A = 30
  Let SD_H4B = 30
  Let SD_H4C = 30

  Let MTTF_H5A = 5000
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```
Let MTTF_H5B = 5000
Let MTTF_H5C = 5000
Let MTTR_H5A = 30
Let MTTR_H5B = 30
Let MTTR_H5C = 30
Let SD_H5A = 30
Let SD_H5B = 30
Let SD_H5C = 30

Let A = 1
Let B = 2
Let C = 3

If RESET = "YES"
  Destroy every LPH3
  Create every LPH3(3)
  U.LPH3(A) = 1
  U.LPH3(B) = 1
  U.LPH3(C) = 1
  Let LPH3.CAP(A) = 0.334
  Let LPH3.CAP(B) = 0.334
  Let LPH3.CAP(C) = 0.334
  Let LPH3.FT(A) = Exponential.f(MTTF_H3A,4)
  Let LPH3.FT(B) = Exponential.f(MTTF_H3B,5)
  Let LPH3.FT(C) = Exponential.f(MTTF_H3C,6)
  Let LPH3.RT(A) = Log.Normal.f(MTTR_H3A,SD_H3A,7)
  Let LPH3.RT(B) = Log.Normal.f(MTTR_H3B,SD_H3B,8)
  Let LPH3.RT(C) = Log.Normal.f(MTTR_H3C,SD_H3C,9)

  Destroy every LPH4
  Create every LPH4(3)
  U.LPH4(A) = 1
  U.LPH4(B) = 1
  U.LPH4(C) = 1
  Let LPH4.CAP(A) = 0.334
  Let LPH4.CAP(B) = 0.334
  Let LPH4.CAP(C) = 0.334
  Let LPH4.FT(A) = Exponential.f(MTTF_H4A,1)
  Let LPH4.FT(B) = Exponential.f(MTTF_H4B,2)
  Let LPH4.FT(C) = Exponential.f(MTTF_H4C,3)
  Let LPH4.RT(A) = Log.Normal.f(MTTR_H4A,SD_H4A,4)
  Let LPH4.RT(B) = Log.Normal.f(MTTR_H4B,SD_H4B,5)
  Let LPH4.RT(C) = Log.Normal.f(MTTR_H4C,SD_H4C,6)

  Destroy every LPH5
  Create every LPH5(3)
  U.LPH5(A) = 1
  U.LPH5(B) = 1
  U.LPH5(C) = 1
  Let LPH5.CAP(A) = 0.334
  Let LPH5.CAP(B) = 0.334
  Let LPH5.CAP(C) = 0.334
  Let LPH5.FT(A) = Exponential.f(MTTF_H5A,7)
  Let LPH5.FT(B) = Exponential.f(MTTF_H5B,8)
  Let LPH5.FT(C) = Exponential.f(MTTF_H5C,9)
  Let LPH5.RT(A) = Log.Normal.f(MTTR_H5A,SD_H5A,1)
  Let LPH5.RT(B) = Log.Normal.f(MTTR_H5B,SD_H5B,2)
  Let LPH5.RT(C) = Log.Normal.f(MTTR_H5C,SD_H5C,3)
Always

If time.v>=LPH3.FT(A) or time.v>=LPH4.FT(A) or time.v>=LPH5.FT(A)
  If time.v >= LPH3.FT(A)
    Let LPH3.CAP(A) = 0
    If time.v >= (LPH3.FT(A) + LPH3.RT(A))
      Let LPH3.CAP(A) = 0.334
      Let LPH3.FT(A) = LPH3.FT(A)+LPH3.RT(A)+Exponential.f(MTTF_H3A,4)
      Let LPH3.RT(A) = Log.Normal.f(MTTR_H3A,SD_H3A,7)
    Always
  Always
  If time.v >= LPH4.FT(A)
    Let LPH4.CAP(A) = 0
```

```
    If time.v >= (LPH4.FT(A) + LPH4.RT(A))
      Let LPH4.CAP(A) = 0.334
      Let LPH4.FT(A) = LPH4.FT(A)+LPH4.RT(A)+Exponential.f(MTTF_H4A,1)
      Let LPH4.RT(A) = Log.Normal.f(MTTR_H4A,SD_H4A,4)
    Always
  Always
  If time.v >= LPH5.FT(A)
    Let LPH5.CAP(A) = 0
    If time.v >= (LPH5.FT(A) + LPH5.RT(A))
      Let LPH5.CAP(A) = 0.334
      Let LPH5.FT(A) = LPH5.FT(A)+LPH5.RT(A)+Exponential.f(MTTF_H5A,7)
      Let LPH5.RT(A) = Log.Normal.f(MTTR_H5A,SD_H5A,1)
    Always
  Always
Always

If time.v>=LPH3.FT(B) or time.v>=LPH4.FT(B) or time.v>=LPH5.FT(B)
  If time.v >= LPH3.FT(B)
    Let LPH3.CAP(B) = 0
    If time.v >= (LPH3.FT(B) + LPH3.RT(B))
      Let LPH3.CAP(B) = 0.334
      Let LPH3.FT(B) = LPH3.FT(B)+LPH3.RT(B)+Exponential.f(MTTF_H3B,4)
      Let LPH3.RT(B) = Log.Normal.f(MTTR_H3B,SD_H3B,7)
    Always
  Always
  If time.v >= LPH4.FT(B)
    Let LPH4.CAP(B) = 0
    If time.v >= (LPH4.FT(B) + LPH4.RT(B))
      Let LPH4.CAP(B) = 0.334
      Let LPH4.FT(B) = LPH4.FT(B)+LPH4.RT(B)+Exponential.f(MTTF_H4B,1)
      Let LPH4.RT(B) = Log.Normal.f(MTTR_H4B,SD_H4B,4)
    Always
  Always
  If time.v >= LPH5.FT(B)
    Let LPH5.CAP(B) = 0
    If time.v >= (LPH5.FT(B) + LPH5.RT(B))
      Let LPH5.CAP(B) = 0.334
      Let LPH5.FT(B) = LPH5.FT(B)+LPH5.RT(B)+Exponential.f(MTTF_H5B,7)
      Let LPH5.RT(B) = Log.Normal.f(MTTR_H5B,SD_H5B,1)
    Always
  Always
Always


If time.v>=LPH3.FT(C) or time.v>=LPH4.FT(C) or time.v>=LPH5.FT(C)
  If time.v >= LPH3.FT(C)
    Let LPH3.CAP(C) = 0
    If time.v >= (LPH3.FT(C) + LPH3.RT(C))
      Let LPH3.CAP(C) = 0.334
      Let LPH3.FT(C) = LPH3.FT(C)+LPH3.RT(C)+Exponential.f(MTTF_H3C,4)
      Let LPH3.RT(C) = Log.Normal.f(MTTR_H3C,SD_H3C,7)
    Always
  Always
  If time.v >= LPH4.FT(C)
    Let LPH4.CAP(C) = 0
    If time.v >= (LPH4.FT(C) + LPH4.RT(C))
      Let LPH4.CAP(C) = 0.334
      Let LPH4.FT(C) = LPH4.FT(C)+LPH4.RT(C)+Exponential.f(MTTF_H4C,1)
      Let LPH4.RT(C) = Log.Normal.f(MTTR_H4C,SD_H4C,4)
    Always
  Always
  If time.v >= LPH5.FT(C)
    Let LPH5.CAP(C) = 0
    If time.v >= (LPH5.FT(C) + LPH5.RT(C))
      Let LPH5.CAP(C) = 0.334
      Let LPH5.FT(C) = LPH5.FT(C)+LPH5.RT(C)+Exponential.f(MTTF_H5C,7)
      Let LPH5.RT(C) = Log.Normal.f(MTTR_H5C,SD_H5C,1)
    Always
  Always
Always
```

```
  Let TRAIN1.CAP = Min.f(LPH3.CAP(A),LPH4.CAP(A),LPH5.CAP(A))
  Let TRAIN2.CAP = Min.f(LPH3.CAP(B),LPH4.CAP(B),LPH5.CAP(B))
  Let TRAIN3.CAP = Min.f(LPH3.CAP(C),LPH4.CAP(C),LPH5.CAP(C))

  Let CAPACITY = TRAIN1.CAP + TRAIN2.CAP + TRAIN3.CAP
  Let LPHEAT2.CAP = Min.f(CAPACITY,1)
END
Routine FEEDPUMP

  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTRA, MTTRB, SDA, and SDB as real variables

  Let MTTFA = 1000
  Let MTTFB = 1000
  Let MTTRA = 2
  Let MTTRB = 2
  Let SDA = 4
  Let SDB = 4
  Let A = 1
  Let B = 2

  If RESET = "YES"
    Destroy every FEEDP
    Create every FEEDP(2)
    U.FEEDP(A) = 1
    U.FEEDP(B) = 1
    Let FEEDP.CAP(A) = .5
    Let FEEDP.CAP(B) = .5
    Let FEEDP.FT(A) = Exponential.f(MTTFA,4)
    Let FEEDP.FT(B) = Exponential.f(MTTFB,5)
    Let FEEDP.RT(A) = Log.Normal.f(MTTRA,SDA,6)
    Let FEEDP.RT(B) = Log.Normal.f(MTTRB,SDB,7)
  Always

  If time.v >= FEEDP.FT(A)
    Let FEEDP.CAP(A) = 0.0
    If time.v >= (FEEDP.FT(A) + FEEDP.RT(A))
      Let FEEDP.CAP(A) = 0.5
      Let FEEDP.FT(A) = FEEDP.FT(A)+FEEDP.RT(A)+Exponential.f(MTTFA,4)
      Let FEEDP.RT(A) = Log.Normal.f(MTTRA,SDA,6)
    Always
  Always

  If time.v >= FEEDP.FT(B)
    Let FEEDP.CAP(B) = 0.0
    If time.v >= (FEEDP.FT(B) + FEEDP.RT(B))
      Let FEEDP.CAP(B) = 0.5
      Let FEEDP.FT(B) = FEEDP.FT(B)+FEEDP.RT(B)+Exponential.f(MTTFB,5)
      Let FEEDP.RT(B) = Log.Normal.f(MTTRB,SDB,7)
    Always
  Always

  Let CAPACITY = FEEDP.CAP(A)+FEEDP.CAP(B)
  Let FEEDPUMPS.CAP = Min.f(CAPACITY,1)
END
Routine HPHEAT
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTFC, MTTRA, MTTRB, MTTRC, SDA, SDB, and SDC
    as real variables
  Let MTTFA = 5000
  Let MTTFB = 5000
  Let MTTFC = 5000
  Let MTTRA = 30
  Let MTTRB = 30
  Let MTTRC = 30
  Let SDA = 30
  Let SDB = 30
  Let SDC = 30
  Let A = 1
  Let B = 2
  Let C = 3
```

```
  If RESET = "YES"
    Destroy every HPH
    Create every HPH(3)
    U.HPH(A) = 1
    U.HPH(B) = 1
    U.HPH(C) = 1
    Let HPH.CAP(A) = .334
    Let HPH.CAP(B) = .334
    Let HPH.CAP(C) = .334
    Let HPH.FT(A) = Exponential.f(MTTFA,1)
    Let HPH.FT(B) = Exponential.f(MTTFB,2)
    Let HPH.FT(C) = Exponential.f(MTTFC,3)
    Let HPH.RT(A) = Log.Normal.f(MTTRA,SDA,4)
    Let HPH.RT(B) = Log.Normal.f(MTTRB,SDB,5)
    Let HPH.RT(C) = Log.Normal.f(MTTRC,SDC,6)
  Always

  If time.v >= HPH.FT(A)
    Let HPH.CAP(A) = 0.0
    If time.v >= (HPH.FT(A) + HPH.RT(A))
      Let HPH.CAP(A) = 0.334
      Let HPH.FT(A) = HPH.FT(A)+HPH.RT(A)+Exponential.f(MTTFA,1)
      Let HPH.RT(A) = Log.Normal.f(MTTRA,SDA,4)
    Always
  Always

  If time.v >= HPH.FT(B)
    Let HPH.CAP(B) = 0.0
    If time.v >= (HPH.FT(B) + HPH.RT(B))
      Let HPH.CAP(B) = 0.334
      Let HPH.FT(B) = HPH.FT(B)+HPH.RT(B)+Exponential.f(MTTFB,2)
      Let HPH.RT(B) = Log.Normal.f(MTTRB,SDB,5)
    Always
  Always

  If time.v >= HPH.FT(C)
    Let HPH.CAP(C) = 0.0
    If time.v >= (HPH.FT(C) + HPH.RT(C))
      Let HPH.CAP(C) = 0.334
      Let HPH.FT(C) = HPH.FT(C)+HPH.RT(C)+Exponential.f(MTTFC,3)
      Let HPH.RT(C) = Log.Normal.f(MTTRC,SDC,6)
    Always
  Always

  Let CAPACITY = HPH.CAP(A)+HPH.CAP(B)+HPH.CAP(C)
  Let HPHEAT.CAP = Min.f(CAPACITY,1)
END
Routine STEAM.GENERATOR

Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 10000
  Let MTTR = 60
  Let SD = 60
  Let A = 1

  If RESET = "YES"
    Destroy every STEAM.GEN
    Create every STEAM.GEN(1)
    U.STEAM.GEN(A) = 1
    Let STEAM.GEN.CAP(A) = 1.0
    Let STEAM.GEN.FT(A) = Exponential.f(MTTF,4)
    Let STEAM.GEN.RT(A) = Log.Normal.f(MTTR,SD,5)
  Always

  If time.v >= STEAM.GEN.FT(A)
    Let STEAM.GEN.CAP(A) = 0.0
    If time.v >= (STEAM.GEN.FT(A) + STEAM.GEN.RT(A))
      Let STEAM.GEN.CAP(A) = 1.0
```

```
      Let STEAM.GEN.FT(A) = STEAM.GEN.FT(A)+STEAM.GEN.RT(A)+
                              Exponential.f(MTTF,4)
      Let STEAM.GEN.RT(A) = Log.Normal.f(MTTR,SD,5)
    Always
  Always

  Let CAPACITY = STEAM.GEN.CAP(A)
  Let STEAM.GENERATOR.CAP = Min.f(CAPACITY,1)
END
Routine TURBINE.GENERATOR

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 500
  Let MTTR = 15
  Let SD = 15
  Let A = 1

  If RESET = "YES"
    Destroy every TURB.GEN
    Create every TURB.GEN(1)
    U.TURB.GEN(A) = 1
    Let TURB.GEN.CAP(A) = 1.0
    Let TURB.GEN.FT(A) = Exponential.f(MTTF,6)
    Let TURB.GEN.RT(A) = Log.Normal.f(MTTR,SD,7)
  Always

  If time.v >= TURB.GEN.FT(A)
    Let TURB.GEN.CAP(A) = 0.0
    If time.v >= (TURB.GEN.FT(A) + TURB.GEN.RT(A))
      Let TURB.GEN.CAP(A) = 1.0
      Let TURB.GEN.FT(A) = TURB.GEN.FT(A)+TURB.GEN.RT(A)+Exponential.f(MTTF,6)
      Let TURB.GEN.RT(A) = Log.Normal.f(MTTR,SD,7)
    Always
  Always

  Let CAPACITY = TURB.GEN.CAP(A)
  Let TURBINE.GENERATOR.CAP = Min.f(CAPACITY,1)
END
Routine CONDENSER

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 30
  Let SD = 30
  Let A = 1

  If RESET = "YES"
    Destroy every COND
    Create every COND(1)
    U.COND(A) = 1
    Let COND.CAP(A) = 1.0
    Let COND.FT(A) = Exponential.f(MTTF,8)
    Let COND.RT(A) = Log.Normal.f(MTTR,SD,9)
  Always

  If time.v >= COND.FT(A)
    Let COND.CAP(A) = 0.0
    If time.v >= (COND.FT(A) + COND.RT(A))
      Let COND.CAP(A) = 1.0
      Let COND.FT(A) = COND.FT(A)+COND.RT(A)+
                         Exponential.f(MTTF,8)
      Let COND.RT(A) = Log.Normal.f(MTTR,SD,9)
    Always
  Always

  Let CAPACITY = COND.CAP(A)
  Let CONDENSER.CAP = Min.f(CAPACITY,1)
```

```
END
Routine REACTOR.PUMP

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 2500
  Let MTTR = 20
  Let SD = 20
  Let A = 1

  If RESET = "YES"
    Destroy every RCP
    Create every RCP(1)
    U.RCP(A) = 1
    Let RCP.CAP(A) = 1.0
    Let RCP.FT(A) = Exponential.f(MTTF,8)
    Let RCP.RT(A) = Log.Normal.f(MTTR,SD,9)
  Always

  If time.v >= RCP.FT(A)
    Let RCP.CAP(A) = 0.0
    If time.v >= (RCP.FT(A) + RCP.RT(A))
      Let RCP.CAP(A) = 1.0
      Let RCP.FT(A) = RCP.FT(A)+RCP.RT(A)+Exponential.f(MTTF,8)
      Let RCP.RT(A) = Log.Normal.f(MTTR,SD,9)
    Always
  Always

  Let CAPACITY = RCP.CAP(A)
  Let REACTOR.PUMP.CAP = Min.f(CAPACITY,1)
END
Routine REACTOR

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 10
  Let SD = 10
  Let A = 1

  If RESET = "YES"
    Destroy every REACT
    Create every REACT(1)
    U.REACT(A) = 1
    Let REACT.CAP(A) = 1.0
    Let REACT.FT(A) = Exponential.f(MTTF,8)
    Let REACT.RT(A) = Log.Normal.f(MTTR,SD,9)
  Always

  If time.v >= REACT.FT(A)
    Let REACT.CAP(A) = 0.0
    If time.v >= (REACT.FT(A) + REACT.RT(A))
      Let REACT.CAP(A) = 1.0
      Let REACT.FT(A) = REACT.FT(A)+REACT.RT(A)+Exponential.f(MTTF,8)
      Let REACT.RT(A) = Log.Normal.f(MTTR,SD,9)
    Always
  Always

  Let CAPACITY = REACT.CAP(A)
  Let REACTOR.CAP = Min.f(CAPACITY,1)
END
Routine PRESSURIZER

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 20
  Let SD = 20
```

```
  Let A = 1

  If RESET = "YES"
    Destroy every PRESS
    Create every PRESS(1)
    U.PRESS(A) = 1
    Let PRESS.CAP(A) = 1.0
    Let PRESS.FT(A) = Exponential.f(MTTF,8)
    Let PRESS.RT(A) = Log.Normal.f(MTTR,SD,9)
  Always

  If time.v >= PRESS.FT(A)
    Let PRESS.CAP(A) = 0.0
    If time.v >= (PRESS.FT(A) + PRESS.RT(A))
      Let PRESS.CAP(A) = 1.0
      Let PRESS.FT(A) = PRESS.FT(A)+PRESS.RT(A)+Exponential.f(MTTF,8)
      Let PRESS.RT(A) = Log.Normal.f(MTTR,SD,9)
    Always
  Always

  Let CAPACITY = PRESS.CAP(A)
  Let PRESSURIZER.CAP = Min.f(CAPACITY,1)
END
```

Appendix B: Sample output file from base simulation program.

```
Length of cycle   1000
Number of EFPDs in5000 cycles was    4435198.0
Average number of EFPDs per cycle was    887.0

Individual system availability data
-----------------------------------------------------------
  Feedwater System               Availability      .9369
    Condensate Pump Train        Availability        1.0000
    Steam Jet Air Ejector Train  Availability        .9811
    Turbine Gland Condenser      Availability        .9936
    Low Pressure Heater Train 1  Availability        .9826
    Low Pressure Heater Train 2  Availability        .9828
    Feedwater Pump Train         Availability        .9979
    High Pressure Heater Train   Availability        .9945
  Steam Generator                Availability      .9944
  Turbine Generator              Availability      .9713
  Condensor                      Availability      .9940
  Reactor Coolant Pump           Availability      .9923
  Reactor                        Availability      .9980
  Pressurizer                    Availability      .9956


Overall plant availability data
_____________________________________________________________
  Mean Plant Availability                                 .88704
  Standard Deviation of Mean Plant Availability           .00129
  Standard Deviation of Plant Availability                .05435
Time point    A(t)
-------------------
10     0.952777
20     0.922165
30     0.908696
40     0.897677
50     0.896018
60     0.897728
70     0.891356
80     0.887387
90     0.889553
100    0.894457
110    0.891894
120    0.886198
130    0.885831
140    0.887091
150    0.885704
160    0.887616
170    0.883838
180    0.888969
190    0.882943
200    0.882669
210    0.882102
220    0.884691
230    0.890227
240    0.884802
250    0.883829
260    0.88253
270    0.88539
280    0.882791
290    0.877564
300    0.884228
310    0.885797
320    0.884268
330    0.88644
340    0.885809
350    0.884174
360    0.884508
```

370	0.882439
380	0.87998
390	0.883144
400	0.88471
410	0.882602
420	0.881131
430	0.878495
440	0.88157
450	0.878008
460	0.879039
470	0.878996
480	0.881235
490	0.885792
500	0.88839
510	0.888992
520	0.88613
530	0.886204
540	0.883608
550	0.883651
560	0.882949
570	0.884879
580	0.880043
590	0.884533
600	0.888994
610	0.888995
620	0.884945
630	0.886602
640	0.883206
650	0.887969
660	0.886806
670	0.887371
680	0.889563
690	0.891232
700	0.890268
710	0.891331
720	0.888202
730	0.884734
740	0.885369
750	0.888334
760	0.889609
770	0.881582
780	0.885931
790	0.884868
800	0.883472
810	0.886273
820	0.888506
830	0.883581
840	0.88298
850	0.884134
860	0.883773
870	0.880115
880	0.884536
890	0.886543
900	0.889078
910	0.887544
920	0.886103
930	0.886168
940	0.88386
950	0.881892
960	0.882069
970	0.882644
980	0.880611
990	0.881278
1000	0.881507

Appendix C: Simulation program listing for analytic validation

```
PREAMBLE
  ''The purpose of this program is to model the a nuclear
  ''power plant in simplified block form with a detialed description of the
  ''feedwater system.  Modifications have been made to the flow subrouting
  '' to calculate availability instead of capacity factor.
  Processes include FLOW
  Resources include CONDP, SJAE, GLAND.COND, DCOOL, LPH1, LPH2, LPH3, LPH4,
    LPH5, FEEDP, HPH, STEAM.GEN, TURB.GEN, COND, RCP, REACT, and PRESS
  ''.FT means .FAILURE.TIME; .RT means REPAIR.TIME;
  ''.CAP means CAPACITY; and .AV means AVAILABILITY
  Every CONDP has a CONDP.FT, a CONDP.RT, a CONDP.AV, and a CONDP.CAP
  Every SJAE has a SJAE.FT, a SJAE.RT, a SJAE.AV, and a SJAE.CAP
  Every GLAND.COND has a GLAND.COND.FT, a GLAND.COND.RT, a GLAND.COND.AV,
        and a GLAND.COND.CAP
  Every DCOOL has a DCOOL.FT, a DCOOL.RT, a DCOOL.AV, and a DCOOL.CAP
  Every LPH1 has a LPH1.FT, a LPH1.RT, a LPH1.AV, and a LPH1.CAP
  Every LPH2 has a LPH2.FT, a LPH2.RT, a LPH2.AV, and a LPH2.CAP
  Every LPH3 has a LPH3.FT, a LPH3.RT, a LPH3.AV, and a LPH3.CAP
  Every LPH4 has a LPH4.FT, a LPH4.RT, a LPH4.AV, and a LPH4.CAP
  Every LPH5 has a LPH5.FT, a LPH5.RT, a LPH5.AV, and a LPH5.CAP
  Every FEEDP has a FEEDP.FT, a FEEDP.RT, a FEEDP.AV, and a FEEDP.CAP
  Every HPH has a HPH.FT, a HPH.RT, a HPH.AV, and a HPH.CAP
  Every STEAM.GEN has a STEAM.GEN.FT, a STEAM.GEN.RT, a STEAM.GEN.AV,
        and a STEAM.GEN.CAP
  Every TURB.GEN has a TURB.GEN.FT, a TURB.GEN.RT, a TURB.GEN.AV,
        and a TURB.GEN.CAP
  Every COND has a COND.FT, a COND.RT, a COND.AV, and a COND.CAP
  Every RCP has a RCP.FT, a RCP.RT, a RCP.AV, and a RCP.CAP
  Every REACT has a REACT.FT, a REACT.RT, a REACT.AV, and a REACT.CAP
  Every PRESS has a PRESS.FT, a PRESS.RT, a PRESS.AV, and a PRESS.CAP
    Define CONDP.FT, SJAE.FT, GLAND.COND.FT, DCOOL.FT, LPH1.FT, LPH2.FT,
      LPH3.FT, LPH4.FT, LPH5.FT, FEEDP.FT, HPH.FT, STEAM.GEN.FT, TURB.GEN.FT,
      COND.FT, RCP.FT, REACT.FT, and PRESS.FT as real variables
    Define CONDP.RT, SJAE.RT, GLAND.COND.RT, DCOOL.RT, LPH1.RT, LPH2.RT,
      LPH3.RT, LPH4.RT, LPH5.RT, FEEDP.RT, HPH.RT, STEAM.GEN.RT, TURB.GEN.RT,
      COND.RT, RCP.RT, REACT.RT, and PRESS.RT as real variables
    Define CONDP.CAP, SJAE.CAP, GLAND.COND.CAP, DCOOL.CAP, LPH1.CAP, LPH2.CAP,
      LPH3.CAP, LPH4.CAP, LPH5.CAP, FEEDP.CAP, HPH.CAP, STEAM.GEN.CAP,
      TURB.GEN.CAP, COND.CAP, RCP.CAP, REACT.CAP, and PRESS.CAP
      as real variables
    Define CONDP.AV, SJAE.AV, GLAND.COND.AV, DCOOL.AV, LPH1.AV, LPH2.AV,
      LPH3.AV, LPH4.AV, LPH5.AV, FEEDP.AV, HPH.AV, STEAM.GEN.AV, TURB.GEN.AV,
      COND.AV, RCP.AV, REACT.AV, and PRESS.AV as real variables

  Define RESET as a text variable
  Define EFPD and AVAIL as 1-dimensional, real arrays
  Define NUM.CYCLES and NUM.POINTS as integer variables
  Define TOTAL.EFPD, CYCLE.LENGTH and AVERAGE.EFPD as real variables
  Define CONDENSATE.CAP, STEAM.JET.CAP, GLAND.CONDENSER.CAP, LPHEAT1.CAP,
    LPHEAT2.CAP,FEEDPUMPS.CAP,HPHEAT.CAP,STEAM.GENERATOR.CAP,
    TURBINE.GENERATOR.CAP,CONDENSER.CAP, REACTOR.PUMP.CAP, REACTOR.CAP,
    PRESSURIZER.CAP, and FEEDWATER.CAP as real variables
  Define CAPACITY.FACT, TIME.INCREMENT and AVAIL.AVERAGE as real variables

  Tally MEAN.CAPACITY.FACT as the mean of CAPACITY.FACT
  Tally SD.CAPACITY.FACT as the std.dev of CAPACITY.FACT
  Tally SD.MEAN.CAPACITY.FACT as the std.dev of AVAIL.AVERAGE

  Tally CONDENSATE.AV as the mean of CONDENSATE.CAP
  Tally STEAM.JET.AV as the mean of STEAM.JET.CAP
  Tally GLAND.CONDENSER.AV as the mean of GLAND.CONDENSER.CAP
  Tally LPHEAT1.AV as the mean of LPHEAT1.CAP
  Tally LPHEAT2.AV as the mean of LPHEAT2.CAP
  Tally FEEDPUMPS.AV as the mean of FEEDPUMPS.CAP
  Tally HPHEAT.AV as the mean of HPHEAT.CAP
  Tally CONDENSER.AV as the mean of CONDENSER.CAP
```

```
  Tally REACTOR.PUMP.AV as the mean of REACTOR.PUMP.CAP
  Tally PRESSURIZER.AV as the mean of PRESSURIZER.CAP
  Tally TURBINE.GENERATOR.AV as the mean of TURBINE.GENERATOR.CAP
  Tally REACTOR.AV as the mean of REACTOR.CAP
  Tally STEAM.GENERATOR.AV as the mean of STEAM.GENERATOR.CAP
  Tally FEEDWATER.AV as the mean of FEEDWATER.CAP

END
MAIN
  Activate a FLOW now
  Start simulation
  Open 8 for output, file name = "OUTPUT"
  Use 8 for output
  Begin report

  Print 20 lines with CYCLE.LENGTH, NUM.CYCLES, TOTAL.EFPD, AVERAGE.EFPD,
    FEEDWATER.AV, CONDENSATE.AV, STEAM.JET.AV, GLAND.CONDENSER.AV, LPHEAT1.AV,
    LPHEAT2.AV, FEEDPUMPS.AV, HPHEAT.AV, STEAM.GENERATOR.AV,
    TURBINE.GENERATOR.AV, CONDENSER.AV, REACTOR.PUMP.AV, REACTOR.AV,
    PRESSURIZER.AV thus
    Length of cycle ******
    Number of EFPDs in *** cycles was       ****.*
    Average number of EFPDs per cycle was   ****.*

    Individual system availability data
    -----------------------------------------------------------
      Feedwater System                Availability    **.****
        Condensate Pump Train         Availability        **.****
        Steam Jet Air Ejector Train Availability          **.****
        Turbine Gland Condenser       Availability        **.****
        Low Pressure Heater Train 1 Availability          **.****
        Low Pressure Heater Train 2 Availability          **.****
        Feedwater Pump Train          Availability        **.****
        High Pressure Heater Train    Availability        **.****
      Steam Generator                 Availability    **.****
      Turbine Generator               Availability    **.****
      Condensor                       Availability    **.****
      Reactor Coolant Pump            Availability    **.****
      Reactor                         Availability    **.****
      Pressurizer                     Availability    **.****

  Skip 2 lines

  For Z = 1 to NUM.CYCLES
    DO
      Let CAPACITY.FACT = EFPD(Z)/CYCLE.LENGTH
    LOOP
  Print 2 lines thus
  Overall plant availability data
  ___________________________________________________________
  Print 3 lines with MEAN.CAPACITY.FACT, SD.MEAN.CAPACITY.FACT,
  and SD.CAPACITY.FACT thus
    Mean Plant Availability                           *****.*****
    Standard Deviation of Mean Plant Availability     *****.*****
    Standard Deviation of Plant Availability          *****.*****

  Print 2 lines thus
  Time point    A(t)
  -------------------
  For Y = 1 to NUM.POINTS
    Do
      Let TIME = TIME + TIME.INCREMENT
      Print 1 line with TIME and AVAIL(Y)/NUM.CYCLES thus
  ******        **.*******
    Loop

  End

END
Process FLOW
  Define TIME.TO.MEASURE as a real variable
```

```
  Define POINT as an integer variable

  Let NUM.CYCLES = 5000
  Let CYCLE.LENGTH = 1000
  Let NUM.POINTS = 100
  Reserve EFPD(*) as NUM.CYCLES
  Reserve AVAIL(*) as NUM.POINTS
  Let TIME.INCREMENT = Int.f(CYCLE.LENGTH/NUM.POINTS)

  For I = 1 to NUM.CYCLES
    Do
      Let RESET = "YES"
      Let POINT = 1
      Let time.v = 0
      Let TIME.TO.MEASURE = TIME.INCREMENT
      Until (time.v>=CYCLE.LENGTH)
        Do

          Call FEEDWATER                ''Feedwater System
          Call STEAM.GENERATOR          ''Steam Generators
          Call TURBINE.GENERATOR        ''Turbine Generator
          Call CONDENSER                ''Condenser
          Call REACTOR.PUMP             ''Reactor Coolant Pump
          Call REACTOR                  ''Reactor
          Call PRESSURIZER              ''Pressurizer

          Wait 1 day
          Let RESET = "NO"
          Let TEMP = Min.f(FEEDWATER.CAP,STEAM.GENERATOR.CAP,
                        TURBINE.GENERATOR.CAP,CONDENSER.CAP,REACTOR.PUMP.CAP,
                        REACTOR.CAP,PRESSURIZER.CAP)

          If TEMP >= 1.
            Let CAPACITY = 1.
          Always
          If TEMP < 1.
            Let CAPACITY = 0.
          Always

          If time.v >= TIME.TO.MEASURE
            Let AVAIL(POINT) = AVAIL(POINT) + CAPACITY
            Let POINT = POINT+1
            Let TIME.TO.MEASURE = TIME.TO.MEASURE + TIME.INCREMENT
          Always
          Let EFPD(I) = EFPD(I) + CAPACITY
        Loop

      Let TOTAL.EFPD = TOTAL.EFPD + EFPD(I)
      Let AVAIL.AVERAGE = ((I-1)*AVAIL.AVERAGE + EFPD(I)/CYCLE.LENGTH)/I
    Loop

  Let AVERAGE.EFPD = TOTAL.EFPD / NUM.CYCLES
END
Routine FEEDWATER
  Call CONDENSATE               ''Feedwater System
  Call GLAND.CONDENSER          ''Feedwater System
  Call STEAM.JET                ''Feedwater System
  Call LPHEAT1                  ''Feedwater System
  Call LPHEAT2                  ''Feedwater System
  Call FEEDPUMP                 ''Feedwater System
  Call HPHEAT                   ''Feedwater System
  Let FEEDWATER.CAP=Min.f(1,CONDENSATE.CAP,GLAND.CONDENSER.CAP,STEAM.JET.CAP,
                      LPHEAT1.CAP,LPHEAT2.CAP,FEEDPUMPS.CAP,HPHEAT.CAP)

END
Routine CONDENSATE
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTFC, MTTRA, MTTRB, MTTRC as real variables
  Let MTTFA = 1000
  Let MTTFB = 1000
  Let MTTFC = 1000
```

```
  Let MTTRA = 2
  Let MTTRB = 2
  Let MTTRC = 2
  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every CONDP
    Create every CONDP(3)
    U.CONDP(A) = 1
    U.CONDP(B) = 1
    U.CONDP(C) = 1
    Let CONDP.CAP(A) = .5
    Let CONDP.CAP(B) = .5
    Let CONDP.CAP(C) = .5
    Let CONDP.FT(A) = Exponential.f(MTTFA,1)
    Let CONDP.FT(B) = Exponential.f(MTTFB,2)
    Let CONDP.FT(C) = Exponential.f(MTTFC,3)
    Let CONDP.RT(A) = Exponential.f(MTTRA,4)
    Let CONDP.RT(B) = Exponential.f(MTTRB,5)
    Let CONDP.RT(C) = Exponential.f(MTTRC,6)
  Always

  If time.v >= CONDP.FT(A)
    Let CONDP.CAP(A) = 0.0
    If time.v >= (CONDP.FT(A) + CONDP.RT(A))
      Let CONDP.CAP(A) = 0.5
      Let CONDP.FT(A) = CONDP.FT(A)+CONDP.RT(A)+Exponential.f(MTTFA,1)
      Let CONDP.RT(A) = Exponential.f(MTTRA,4)
    Always
  Always

  If time.v >= CONDP.FT(B)
    Let CONDP.CAP(B) = 0.0
    If time.v >= (CONDP.FT(B) + CONDP.RT(B))
      Let CONDP.CAP(B) = 0.5
      Let CONDP.FT(B) = CONDP.FT(B)+CONDP.RT(B)+Exponential.f(MTTFB,2)
      Let CONDP.RT(B) = Exponential.f(MTTRB,5)
    Always
  Always

  If time.v >= CONDP.FT(C)
    Let CONDP.CAP(C) = 0.0
    If time.v >= (CONDP.FT(C) + CONDP.RT(C))
      Let CONDP.CAP(C) = 0.5
      Let CONDP.FT(C) = CONDP.FT(C)+CONDP.RT(C)+Exponential.f(MTTFC,3)
      Let CONDP.RT(C) = Exponential.f(MTTRC,6)
    Always
  Always

  Let CAPACITY = CONDP.CAP(A)+CONDP.CAP(B)+CONDP.CAP(C)
  Let CONDENSATE.CAP = Min.f(CAPACITY,1)
END
Routine GLAND.CONDENSER

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 30
  Let A = 1

  If RESET = "YES"
    Destroy every GLAND.COND
    Create every GLAND.COND(1)
    U.GLAND.COND(A) = 1
    Let GLAND.COND.CAP(A) = 1.0
    Let GLAND.COND.FT(A) = Exponential.f(MTTF,8)
    Let GLAND.COND.RT(A) = Exponential.f(MTTR,9)
  Always
```

```
  If time.v >= GLAND.COND.FT(A)
    Let GLAND.COND.CAP(A) = 0.0
    If time.v >= (GLAND.COND.FT(A) + GLAND.COND.RT(A))
      Let GLAND.COND.CAP(A) = 1.0
      Let GLAND.COND.FT(A) = GLAND.COND.FT(A)+GLAND.COND.RT(A)+
          Exponential.f(MTTF,8)
      Let GLAND.COND.RT(A) = Exponential.f(MTTR,9)
    Always
  Always

  Let CAPACITY = GLAND.COND.CAP(A)
  Let GLAND.CONDENSER.CAP = Min.f(CAPACITY,1)
END
Routine STEAM.JET
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTFC, MTTRA, MTTRB, MTTRC as real variables

  Let MTTFA = 1000
  Let MTTFB = 1000
  Let MTTFC = 1000
  Let MTTRA = 20
  Let MTTRB = 20
  Let MTTRC = 20
 '' Let SDA = 10
 '' Let SDB = 10
 '' Let SDC = 10
  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every SJAE
    Create every SJAE(3)
    U.SJAE(A) = 1
    U.SJAE(B) = 1
    U.SJAE(C) = 1
    Let SJAE.CAP(A) = 0.5
    Let SJAE.CAP(B) = 0.5
    Let SJAE.CAP(C) = 0.5
    Let SJAE.FT(A) = Exponential.f(MTTFA,7)
    Let SJAE.FT(B) = Exponential.f(MTTFB,8)
    Let SJAE.FT(C) = Exponential.f(MTTFC,9)
    Let SJAE.RT(A) = exponential.f(MTTRA,1)
    Let SJAE.RT(B) = exponential.f(MTTRB,2)
    Let SJAE.RT(C) = exponential.f(MTTRC,3)
  Always

  If time.v >= SJAE.FT(A)
    Let SJAE.CAP(A) = 0.0
    If time.v >= (SJAE.FT(A) + SJAE.RT(A))
      Let SJAE.CAP(A) = 0.5
      Let SJAE.FT(A) = SJAE.FT(A)+SJAE.RT(A)+Exponential.f(MTTFA,7)
      Let SJAE.RT(A) = exponential.f(MTTRA,1)
    Always
  Always

  If time.v >= SJAE.FT(B)
    Let SJAE.CAP(B) = 0.0
    If time.v >= (SJAE.FT(B) + SJAE.RT(B))
      Let SJAE.CAP(B) = 0.5
      Let SJAE.FT(B) = SJAE.FT(B)+SJAE.RT(B)+Exponential.f(MTTFB,8)
      Let SJAE.RT(B) = exponential.f(MTTRB,2)
    Always
  Always

  If time.v >= SJAE.FT(C)
    Let SJAE.CAP(C) = 0.0
    If time.v >= (SJAE.FT(C) + SJAE.RT(C))
      Let SJAE.CAP(C) = 0.5
      Let SJAE.FT(C) = SJAE.FT(C)+SJAE.RT(C)+Exponential.f(MTTFC,9)
```

```
      Let SJAE.RT(C) = exponential.f(MTTRC,3)
    Always
  Always

  Let CAPACITY = SJAE.CAP(A)+SJAE.CAP(B)+SJAE.CAP(C)
  Let STEAM.JET.CAP = Min.f(CAPACITY,1)
END
Routine LPHEAT1
  Define CAPACITY as a real variable
  Define MTTF_DCA, MTTF_H1A, MTTF_H2A, MTTF_DCB, MTTF_H1B, MTTF_H2B,
    MTTF_DCC, MTTF_H1C, MTTF_H2C, MTTR_DCA, MTTR_H1A, MTTR_H2A,
    MTTR_DCB, MTTR_H1B, MTTR_H2B, MTTR_DCC, MTTR_H1C, MTTR_H2C
    as real variables

  Let MTTF_DCA = 5000
  Let MTTF_DCB = 5000
  Let MTTF_DCC = 5000
  Let MTTR_DCA = 30
  Let MTTR_DCB = 30
  Let MTTR_DCC = 30

  Let MTTF_H1A = 5000
  Let MTTF_H1B = 5000
  Let MTTF_H1C = 5000
  Let MTTR_H1A = 30
  Let MTTR_H1B = 30
  Let MTTR_H1C = 30

  Let MTTF_H2A = 5000
  Let MTTF_H2B = 5000
  Let MTTF_H2C = 5000
  Let MTTR_H2A = 30
  Let MTTR_H2B = 30
  Let MTTR_H2C = 30


  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every DCOOL
    Create every DCOOL(3)
    U.DCOOL(A) = 1
    U.DCOOL(B) = 1
    U.DCOOL(C) = 1
    Let DCOOL.CAP(A) = 0.5
    Let DCOOL.CAP(B) = 0.5
    Let DCOOL.CAP(C) = 0.5
    Let DCOOL.FT(A) = Exponential.f(MTTF_DCA,4)
    Let DCOOL.FT(B) = Exponential.f(MTTF_DCB,5)
    Let DCOOL.FT(C) = Exponential.f(MTTF_DCC,6)
    Let DCOOL.RT(A) = Exponential.f(MTTR_DCA,7)
    Let DCOOL.RT(B) = Exponential.f(MTTR_DCB,8)
    Let DCOOL.RT(C) = Exponential.f(MTTR_DCC,9)

    Destroy every LPH1
    Create every LPH1(3)
    U.LPH1(A) = 1
    U.LPH1(B) = 1
    U.LPH1(C) = 1
    Let LPH1.CAP(A) = 0.5
    Let LPH1.CAP(B) = 0.5
    Let LPH1.CAP(C) = 0.5
    Let LPH1.FT(A) = Exponential.f(MTTF_H1A,1)
    Let LPH1.FT(B) = Exponential.f(MTTF_H1B,2)
    Let LPH1.FT(C) = Exponential.f(MTTF_H1C,3)
    Let LPH1.RT(A) = Exponential.f(MTTR_H1A,4)
    Let LPH1.RT(B) = Exponential.f(MTTR_H1B,5)
    Let LPH1.RT(C) = exponential.f(MTTR_H1C,6)
```

```
  Destroy every LPH2
  Create every LPH2(3)
  U.LPH2(A) = 1
  U.LPH2(B) = 1
  U.LPH2(C) = 1
  Let LPH2.CAP(A) = 0.5
  Let LPH2.CAP(B) = 0.5
  Let LPH2.CAP(C) = 0.5
  Let LPH2.FT(A) = Exponential.f(MTTF_H2A,7)
  Let LPH2.FT(B) = Exponential.f(MTTF_H2B,8)
  Let LPH2.FT(C) = Exponential.f(MTTF_H2C,9)
  Let LPH2.RT(A) = exponential.f(MTTR_H2A,1)
  Let LPH2.RT(B) = exponential.f(MTTR_H2B,2)
  Let LPH2.RT(C) = exponential.f(MTTR_H2C,3)
Always

If time.v>=DCOOL.FT(A) or time.v>=LPH1.FT(A) or time.v>=LPH2.FT(A)
  If time.v >= DCOOL.FT(A)
    Let DCOOL.CAP(A) = 0
    If time.v >= (DCOOL.FT(A) + DCOOL.RT(A))
      Let DCOOL.CAP(A) = 0.5
      Let DCOOL.FT(A) = DCOOL.FT(A)+DCOOL.RT(A)+Exponential.f(MTTF_DCA,4)
      Let DCOOL.RT(A) = exponential.f(MTTR_DCA,7)
    Always
  Always
  If time.v >= LPH1.FT(A)
    Let LPH1.CAP(A) = 0
    If time.v >= (LPH1.FT(A) + LPH1.RT(A))
      Let LPH1.CAP(A) = 0.5
      Let LPH1.FT(A) = LPH1.FT(A)+LPH1.RT(A)+Exponential.f(MTTF_H1A,1)
      Let LPH1.RT(A) = exponential.f(MTTR_H1A,4)
    Always
  Always
  If time.v >= LPH2.FT(A)
    Let LPH2.CAP(A) = 0
    If time.v >= (LPH2.FT(A) + LPH2.RT(A))
      Let LPH2.CAP(A) = 0.5
      Let LPH2.FT(A) = LPH2.FT(A)+LPH2.RT(A)+Exponential.f(MTTF_H2A,7)
      Let LPH2.RT(A) = exponential.f(MTTR_H2A,1)
    Always
  Always
Always

If time.v>=DCOOL.FT(B) or time.v>=LPH1.FT(B) or time.v>=LPH2.FT(B)
  If time.v >= DCOOL.FT(B)
    Let DCOOL.CAP(B) = 0
    If time.v >= (DCOOL.FT(B) + DCOOL.RT(B))
      Let DCOOL.CAP(B) = 0.5
      Let DCOOL.FT(B) = DCOOL.FT(B)+DCOOL.RT(B)+Exponential.f(MTTF_DCB,4)
      Let DCOOL.RT(B) = exponential.f(MTTR_DCB,7)
    Always
  Always
  If time.v >= LPH1.FT(B)
    Let LPH1.CAP(B) = 0
    If time.v >= (LPH1.FT(B) + LPH1.RT(B))
      Let LPH1.CAP(B) = 0.5
      Let LPH1.FT(B) = LPH1.FT(B)+LPH1.RT(B)+Exponential.f(MTTF_H1B,1)
      Let LPH1.RT(B) = exponential.f(MTTR_H1B,4)
    Always
  Always
  If time.v >= LPH2.FT(B)
    Let LPH2.CAP(B) = 0
    If time.v >= (LPH2.FT(B) + LPH2.RT(B))
      Let LPH2.CAP(B) = 0.5
      Let LPH2.FT(B) = LPH2.FT(B)+LPH2.RT(B)+Exponential.f(MTTF_H2B,7)
      Let LPH2.RT(B) = exponential.f(MTTR_H2B,1)
    Always
  Always
Always

If time.v>=DCOOL.FT(C) or time.v>=LPH1.FT(C) or time.v>=LPH2.FT(C)
```

```
    If time.v >= DCOOL.FT(C)
      Let DCOOL.CAP(C) = 0
      If time.v >= (DCOOL.FT(C) + DCOOL.RT(C))
        Let DCOOL.CAP(C) = 0.5
        Let DCOOL.FT(C) = DCOOL.FT(C)+DCOOL.RT(C)+Exponential.f(MTTF_DCC,4)
        Let DCOOL.RT(C) = exponential.f(MTTR_DCC,7)
      Always
    Always
    If time.v >= LPH1.FT(C)
      Let LPH1.CAP(C) = 0
      If time.v >= (LPH1.FT(C) + LPH1.RT(C))
        Let LPH1.CAP(C) = 0.5
        Let LPH1.FT(C) = LPH1.FT(C)+LPH1.RT(C)+Exponential.f(MTTF_H1C,1)
        Let LPH1.RT(C) = exponential.f(MTTR_H1C,4)
      Always
    Always
    If time.v >= LPH2.FT(C)
      Let LPH2.CAP(C) = 0
      If time.v >= (LPH2.FT(C) + LPH2.RT(C))
        Let LPH2.CAP(C) = 0.5
        Let LPH2.FT(C) = LPH2.FT(C)+LPH2.RT(C)+Exponential.f(MTTF_H2C,7)
        Let LPH2.RT(C) = exponential.f(MTTR_H2C,1)
      Always
    Always
  Always

  Let TRAIN1.CAP = Min.f(DCOOL.CAP(A),LPH1.CAP(A),LPH2.CAP(A))
  Let TRAIN2.CAP = Min.f(DCOOL.CAP(B),LPH1.CAP(B),LPH2.CAP(B))
  Let TRAIN3.CAP = Min.f(DCOOL.CAP(C),LPH1.CAP(C),LPH2.CAP(C))

  Let CAPACITY = TRAIN1.CAP + TRAIN2.CAP + TRAIN3.CAP
  Let LPHEAT1.CAP = Min.f(CAPACITY,1)
END

Routine LPHEAT2
  Define CAPACITY as a real variable
  Define MTTF_H3A, MTTF_H4A, MTTF_H5A, MTTF_H3B, MTTF_H4B, MTTF_H5B,
    MTTF_H3C, MTTF_H4C, MTTF_H5C, MTTR_H3A, MTTR_H4A, MTTR_H5A,
    MTTR_H3B, MTTR_H4B, MTTR_H5B, MTTR_H3C, MTTR_H4C, MTTR_H5C
    as real variables

  Let MTTF_H3A = 5000
  Let MTTF_H3B = 5000
  Let MTTF_H3C = 5000
  Let MTTR_H3A = 30
  Let MTTR_H3B = 30
  Let MTTR_H3C = 30
  ''Let SD_H3A = 10
  ''Let SD_H3B = 10
  ''Let SD_H3C = 10

  Let MTTF_H4A = 5000
  Let MTTF_H4B = 5000
  Let MTTF_H4C = 5000
  Let MTTR_H4A = 30
  Let MTTR_H4B = 30
  Let MTTR_H4C = 30
  ''Let SD_H4A = 10
  ''Let SD_H4B = 10
  ''Let SD_H4C = 10

  Let MTTF_H5A = 5000
  Let MTTF_H5B = 5000
  Let MTTF_H5C = 5000
  Let MTTR_H5A = 30
  Let MTTR_H5B = 30
  Let MTTR_H5C = 30
  ''Let SD_H5A = 10
  ''Let SD_H5B = 10
  ''Let SD_H5C = 10
```

```
Let A = 1
Let B = 2
Let C = 3

If RESET = "YES"
  Destroy every LPH3
  Create every LPH3(3)
  U.LPH3(A) = 1
  U.LPH3(B) = 1
  U.LPH3(C) = 1
  Let LPH3.CAP(A) = 0.5
  Let LPH3.CAP(B) = 0.5
  Let LPH3.CAP(C) = 0.5
  Let LPH3.FT(A) = Exponential.f(MTTF_H3A,4)
  Let LPH3.FT(B) = Exponential.f(MTTF_H3B,5)
  Let LPH3.FT(C) = Exponential.f(MTTF_H3C,6)
  Let LPH3.RT(A) = exponential.f(MTTR_H3A,7)
  Let LPH3.RT(B) = exponential.f(MTTR_H3B,8)
  Let LPH3.RT(C) = exponential.f(MTTR_H3C,9)

  Destroy every LPH4
  Create every LPH4(3)
  U.LPH4(A) = 1
  U.LPH4(B) = 1
  U.LPH4(C) = 1
  Let LPH4.CAP(A) = 0.5
  Let LPH4.CAP(B) = 0.5
  Let LPH4.CAP(C) = 0.5
  Let LPH4.FT(A) = Exponential.f(MTTF_H4A,1)
  Let LPH4.FT(B) = Exponential.f(MTTF_H4B,2)
  Let LPH4.FT(C) = Exponential.f(MTTF_H4C,3)
  Let LPH4.RT(A) = exponential.f(MTTR_H4A,4)
  Let LPH4.RT(B) = exponential.f(MTTR_H4B,5)
  Let LPH4.RT(C) = exponential.f(MTTR_H4C,6)

  Destroy every LPH5
  Create every LPH5(3)
  U.LPH5(A) = 1
  U.LPH5(B) = 1
  U.LPH5(C) = 1
  Let LPH5.CAP(A) = 0.5
  Let LPH5.CAP(B) = 0.5
  Let LPH5.CAP(C) = 0.5
  Let LPH5.FT(A) = Exponential.f(MTTF_H5A,7)
  Let LPH5.FT(B) = Exponential.f(MTTF_H5B,8)
  Let LPH5.FT(C) = Exponential.f(MTTF_H5C,9)
  Let LPH5.RT(A) = exponential.f(MTTR_H5A,1)
  Let LPH5.RT(B) = exponential.f(MTTR_H5B,2)
  Let LPH5.RT(C) = exponential.f(MTTR_H5C,3)
Always

If time.v>=LPH3.FT(A) or time.v>=LPH4.FT(A) or time.v>=LPH5.FT(A)
  If time.v >= LPH3.FT(A)
    Let LPH3.CAP(A) = 0
    If time.v >= (LPH3.FT(A) + LPH3.RT(A))
      Let LPH3.CAP(A) = 0.5
      Let LPH3.FT(A) = LPH3.FT(A)+LPH3.RT(A)+Exponential.f(MTTF_H3A,4)
      Let LPH3.RT(A) = exponential.f(MTTR_H3A,7)
    Always
  Always
  If time.v >= LPH4.FT(A)
    Let LPH4.CAP(A) = 0
    If time.v >= (LPH4.FT(A) + LPH4.RT(A))
      Let LPH4.CAP(A) = 0.5
      Let LPH4.FT(A) = LPH4.FT(A)+LPH4.RT(A)+Exponential.f(MTTF_H4A,1)
      Let LPH4.RT(A) = exponential.f(MTTR_H4A,4)
    Always
  Always
  If time.v >= LPH5.FT(A)
    Let LPH5.CAP(A) = 0
    If time.v >= (LPH5.FT(A) + LPH5.RT(A))
```

```
        Let LPH5.CAP(A) = 0.5
        Let LPH5.FT(A) = LPH5.FT(A)+LPH5.RT(A)+Exponential.f(MTTF_H5A,7)
        Let LPH5.RT(A) = exponential.f(MTTR_H5A,1)
      Always
    Always
  Always

  If time.v>=LPH3.FT(B) or time.v>=LPH4.FT(B) or time.v>=LPH5.FT(B)
    If time.v >= LPH3.FT(B)
      Let LPH3.CAP(B) = 0
      If time.v >= (LPH3.FT(B) + LPH3.RT(B))
        Let LPH3.CAP(B) = 0.5
        Let LPH3.FT(B) = LPH3.FT(B)+LPH3.RT(B)+Exponential.f(MTTF_H3B,4)
        Let LPH3.RT(B) = exponential.f(MTTR_H3B,7)
      Always
    Always
    If time.v >= LPH4.FT(B)
      Let LPH4.CAP(B) = 0
      If time.v >= (LPH4.FT(B) + LPH4.RT(B))
        Let LPH4.CAP(B) = 0.5
        Let LPH4.FT(B) = LPH4.FT(B)+LPH4.RT(B)+Exponential.f(MTTF_H4B,1)
        Let LPH4.RT(B) = exponential.f(MTTR_H4B,4)
      Always
    Always
    If time.v >= LPH5.FT(B)
      Let LPH5.CAP(B) = 0
      If time.v >= (LPH5.FT(B) + LPH5.RT(B))
        Let LPH5.CAP(B) = 0.5
        Let LPH5.FT(B) = LPH5.FT(B)+LPH5.RT(B)+Exponential.f(MTTF_H5B,7)
        Let LPH5.RT(B) = exponential.f(MTTR_H5B,1)
      Always
    Always
  Always


  If time.v>=LPH3.FT(C) or time.v>=LPH4.FT(C) or time.v>=LPH5.FT(C)
    If time.v >= LPH3.FT(C)
      Let LPH3.CAP(C) = 0
      If time.v >= (LPH3.FT(C) + LPH3.RT(C))
        Let LPH3.CAP(C) = 0.5
        Let LPH3.FT(C) = LPH3.FT(C)+LPH3.RT(C)+Exponential.f(MTTF_H3C,4)
        Let LPH3.RT(C) = exponential.f(MTTR_H3C,7)
      Always
    Always
    If time.v >= LPH4.FT(C)
      Let LPH4.CAP(C) = 0
      If time.v >= (LPH4.FT(C) + LPH4.RT(C))
        Let LPH4.CAP(C) = 0.5
        Let LPH4.FT(C) = LPH4.FT(C)+LPH4.RT(C)+Exponential.f(MTTF_H4C,1)
        Let LPH4.RT(C) = exponential.f(MTTR_H4C,4)
      Always
    Always
    If time.v >= LPH5.FT(C)
      Let LPH5.CAP(C) = 0
      If time.v >= (LPH5.FT(C) + LPH5.RT(C))
        Let LPH5.CAP(C) = 0.5
        Let LPH5.FT(C) = LPH5.FT(C)+LPH5.RT(C)+Exponential.f(MTTF_H5C,7)
        Let LPH5.RT(C) = exponential.f(MTTR_H5C,1)
      Always
    Always
  Always

  Let TRAIN1.CAP = Min.f(LPH3.CAP(A),LPH4.CAP(A),LPH5.CAP(A))
  Let TRAIN2.CAP = Min.f(LPH3.CAP(B),LPH4.CAP(B),LPH5.CAP(B))
  Let TRAIN3.CAP = Min.f(LPH3.CAP(C),LPH4.CAP(C),LPH5.CAP(C))

  Let CAPACITY = TRAIN1.CAP + TRAIN2.CAP + TRAIN3.CAP
  Let LPHEAT2.CAP = Min.f(CAPACITY,1)
END
Routine FEEDPUMP
```

```
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTRA, MTTRB  as real variables

  Let MTTFA = 1000
  Let MTTFB = 1000
  Let MTTRA = 2
  Let MTTRB = 2
  Let A = 1
  Let B = 2

  If RESET = "YES"
    Destroy every FEEDP
    Create every FEEDP(2)
    U.FEEDP(A) = 1
    U.FEEDP(B) = 1
    Let FEEDP.CAP(A) =1.
    Let FEEDP.CAP(B) =1.
    Let FEEDP.FT(A) = Exponential.f(MTTFA,4)
    Let FEEDP.FT(B) = Exponential.f(MTTFB,5)
    Let FEEDP.RT(A) = Exponential.f(MTTRA,6)
    Let FEEDP.RT(B) = Exponential.f(MTTRB,7)
  Always

  If time.v >= FEEDP.FT(A)
    Let FEEDP.CAP(A) = 0.0
    If time.v >= (FEEDP.FT(A) + FEEDP.RT(A))
      Let FEEDP.CAP(A) = 1.
      Let FEEDP.FT(A) = FEEDP.FT(A)+FEEDP.RT(A)+Exponential.f(MTTFA,4)
      Let FEEDP.RT(A) = Exponential.f(MTTRA,6)
    Always
  Always

  If time.v >= FEEDP.FT(B)
    Let FEEDP.CAP(B) = 0.0
    If time.v >= (FEEDP.FT(B) + FEEDP.RT(B))
      Let FEEDP.CAP(B) = 1.
      Let FEEDP.FT(B) = FEEDP.FT(B)+FEEDP.RT(B)+Exponential.f(MTTFB,5)
      Let FEEDP.RT(B) = Exponential.f(MTTRB,7)
    Always
  Always

  Let CAPACITY = FEEDP.CAP(A)+FEEDP.CAP(B)
  Let FEEDPUMPS.CAP = Min.f(CAPACITY,1)
END
Routine HPHEAT
  Define CAPACITY as a real variable
  Define MTTFA, MTTFB, MTTFC, MTTRA, MTTRB, MTTRC as real variables
  Let MTTFA = 5000
  Let MTTFB = 5000
  Let MTTFC = 5000
  Let MTTRA = 30
  Let MTTRB = 30
  Let MTTRC = 30
  Let A = 1
  Let B = 2
  Let C = 3

  If RESET = "YES"
    Destroy every HPH
    Create every HPH(3)
    U.HPH(A) = 1
    U.HPH(B) = 1
    U.HPH(C) = 1
    Let HPH.CAP(A) = .5
    Let HPH.CAP(B) = .5
    Let HPH.CAP(C) = .5
    Let HPH.FT(A) = Exponential.f(MTTFA,1)
    Let HPH.FT(B) = Exponential.f(MTTFB,2)
    Let HPH.FT(C) = Exponential.f(MTTFC,3)
    Let HPH.RT(A) = Exponential.f(MTTRA,4)
    Let HPH.RT(B) = Exponential.f(MTTRB,5)
```

```
    Let HPH.RT(C) = Exponential.f(MTTRC,6)
  Always

  If time.v >= HPH.FT(A)
    Let HPH.CAP(A) = 0.0
    If time.v >= (HPH.FT(A) + HPH.RT(A))
      Let HPH.CAP(A) = 0.5
      Let HPH.FT(A) = HPH.FT(A)+HPH.RT(A)+Exponential.f(MTTFA,1)
      Let HPH.RT(A) = Exponential.f(MTTRA,4)
    Always
  Always

  If time.v >= HPH.FT(B)
    Let HPH.CAP(B) = 0.0
    If time.v >= (HPH.FT(B) + HPH.RT(B))
      Let HPH.CAP(B) = 0.5
      Let HPH.FT(B) = HPH.FT(B)+HPH.RT(B)+Exponential.f(MTTFB,2)
      Let HPH.RT(B) = Exponential.f(MTTRB,5)
    Always
  Always

  If time.v >= HPH.FT(C)
    Let HPH.CAP(C) = 0.0
    If time.v >= (HPH.FT(C) + HPH.RT(C))
      Let HPH.CAP(C) = 0.5
      Let HPH.FT(C) = HPH.FT(C)+HPH.RT(C)+Exponential.f(MTTFC,3)
      Let HPH.RT(C) = Exponential.f(MTTRC,6)
    Always
  Always

  Let CAPACITY = HPH.CAP(A)+HPH.CAP(B)+HPH.CAP(C)
  Let HPHEAT.CAP = Min.f(CAPACITY,1)
END
Routine STEAM.GENERATOR

Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 10000
  Let MTTR = 60
   Let A = 1

  If RESET = "YES"
    Destroy every STEAM.GEN
    Create every STEAM.GEN(1)
    U.STEAM.GEN(A) = 1
    Let STEAM.GEN.CAP(A) = 1.0
    Let STEAM.GEN.FT(A) = Exponential.f(MTTF,4)
    Let STEAM.GEN.RT(A) = Exponential.f(MTTR,5)
  Always

  If time.v >= STEAM.GEN.FT(A)
    Let STEAM.GEN.CAP(A) = 0.0
    If time.v >= (STEAM.GEN.FT(A) + STEAM.GEN.RT(A))
      Let STEAM.GEN.CAP(A) = 1.0
      Let STEAM.GEN.FT(A) = STEAM.GEN.FT(A)+STEAM.GEN.RT(A)+
                              Exponential.f(MTTF,4)
      Let STEAM.GEN.RT(A) = Exponential.f(MTTR,5)
    Always
  Always

  Let CAPACITY = STEAM.GEN.CAP(A)
  Let STEAM.GENERATOR.CAP = Min.f(CAPACITY,1)
END
Routine TURBINE.GENERATOR

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 500
  Let MTTR = 15
```

```
  Let A = 1

  If RESET = "YES"
    Destroy every TURB.GEN
    Create every TURB.GEN(1)
    U.TURB.GEN(A) = 1
    Let TURB.GEN.CAP(A) = 1.0
    Let TURB.GEN.FT(A) = Exponential.f(MTTF,6)
    Let TURB.GEN.RT(A) = Exponential.f(MTTR,7)
  Always

  If time.v >= TURB.GEN.FT(A)
    Let TURB.GEN.CAP(A) = 0.0
    If time.v >= (TURB.GEN.FT(A) + TURB.GEN.RT(A))
      Let TURB.GEN.CAP(A) = 1.0
      Let TURB.GEN.FT(A) = TURB.GEN.FT(A)+TURB.GEN.RT(A)+Exponential.f(MTTF,6)
      Let TURB.GEN.RT(A) = Exponential.f(MTTR,7)
    Always
  Always

  Let CAPACITY = TURB.GEN.CAP(A)
  Let TURBINE.GENERATOR.CAP = Min.f(CAPACITY,1)
END
Routine CONDENSER

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 30
  Let A = 1

  If RESET = "YES"
    Destroy every COND
    Create every COND(1)
    U.COND(A) = 1
    Let COND.CAP(A) = 1.0
    Let COND.FT(A) = Exponential.f(MTTF,8)
    Let COND.RT(A) = Exponential.f(MTTR,9)
  Always

  If time.v >= COND.FT(A)
    Let COND.CAP(A) = 0.0
    If time.v >= (COND.FT(A) + COND.RT(A))
      Let COND.CAP(A) = 1.0
      Let COND.FT(A) = COND.FT(A)+COND.RT(A)+
                                Exponential.f(MTTF,8)
      Let COND.RT(A) = Exponential.f(MTTR,9)
    Always
  Always

  Let CAPACITY = COND.CAP(A)
  Let CONDENSER.CAP = Min.f(CAPACITY,1)
END
Routine REACTOR.PUMP

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 2500
  Let MTTR = 20
  Let A = 1

  If RESET = "YES"
    Destroy every RCP
    Create every RCP(1)
    U.RCP(A) = 1
    Let RCP.CAP(A) = 1.0
    Let RCP.FT(A) = Exponential.f(MTTF,8)
    Let RCP.RT(A) = Exponential.f(MTTR,9)
  Always
```

```
  If time.v >= RCP.FT(A)
    Let RCP.CAP(A) = 0.0
    If time.v >= (RCP.FT(A) + RCP.RT(A))
      Let RCP.CAP(A) = 1.0
      Let RCP.FT(A) = RCP.FT(A)+RCP.RT(A)+Exponential.f(MTTF,8)
      Let RCP.RT(A) = Exponential.f(MTTR,9)
    Always
  Always

  Let CAPACITY = RCP.CAP(A)
  Let REACTOR.PUMP.CAP = Min.f(CAPACITY,1)
END
Routine REACTOR

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 10
  Let A = 1

  If RESET = "YES"
    Destroy every REACT
    Create every REACT(1)
    U.REACT(A) = 1
    Let REACT.CAP(A) = 1.0
    Let REACT.FT(A) = Exponential.f(MTTF,8)
    Let REACT.RT(A) = Exponential.f(MTTR,9)
  Always

  If time.v >= REACT.FT(A)
    Let REACT.CAP(A) = 0.0
    If time.v >= (REACT.FT(A) + REACT.RT(A))
      Let REACT.CAP(A) = 1.0
      Let REACT.FT(A) = REACT.FT(A)+REACT.RT(A)+Exponential.f(MTTF,8)
      Let REACT.RT(A) = Exponential.f(MTTR,9)
    Always
  Always

  Let CAPACITY = REACT.CAP(A)
  Let REACTOR.CAP = Min.f(CAPACITY,1)
END
Routine PRESSURIZER

  Define CAPACITY as a real variable
  Define MTTF, MTTR as real variables

  Let MTTF = 5000
  Let MTTR = 20
  Let A = 1

  If RESET = "YES"
    Destroy every PRESS
    Create every PRESS(1)
    U.PRESS(A) = 1
    Let PRESS.CAP(A) = 1.0
    Let PRESS.FT(A) = Exponential.f(MTTF,8)
    Let PRESS.RT(A) = Exponential.f(MTTR,9)
  Always

  If time.v >= PRESS.FT(A)
    Let PRESS.CAP(A) = 0.0
    If time.v >= (PRESS.FT(A) + PRESS.RT(A))
      Let PRESS.CAP(A) = 1.0
      Let PRESS.FT(A) = PRESS.FT(A)+PRESS.RT(A)+Exponential.f(MTTF,8)
      Let PRESS.RT(A) = Exponential.f(MTTR,9)
    Always
  Always

  Let CAPACITY = PRESS.CAP(A)
```

```
  Let PRESSURIZER.CAP = Min.f(CAPACITY,1)
END
```

Appendix D - Mathcad listing used in analytic verification of simulation.

1. Notation:

Availability of each system: $AS_i \quad i = 1..7$

Feedwater System:	AS_1
Steam generator:	AS_2
Turbine Generator:	AS_3
Condensor:	AS_4
Reactor Coolant Pump:	AS_5
Reactor:	AS_6
Pressurizer:	AS_7

Availability of each block in Feedwater System: $AB_j \quad j = 1..7$

Condensate Pumps Block:	AB_1
Steam Jet/Air Ejectors Block:	AB_2
Steam Gland Condenser Block:	AB_3
Low Pressure Heaters Block 1:	AB_4
Low Pressure Heaters Block 2:	AB_5
Feedwater Pumps Blcok:	AB_6
High Pressure Heaters Block:	AB_7

Availability of each component in Feedwater System: $AC_k \quad k = 1..6$

Condensate Pump:	AC_1
Steam Jet:	AC_2
Drain Cooler:	AC_3
Heater:	AC_4
Feedwater Pump:	AC_5
Gland Condenser:	AC_6

2. Time Point to be calculated:

$T := 1000$

3. Calculation of Availability of Feedwater System:

A. Availability of each component:

Mean Time To Failure of each component: $MTTFC_k$

Mean Time To Repair of each component: $MTTRC_k$

	$MTTFC_k :=$	$MTTRC_k :=$
Condensate Pump:	1000	2
Steam Jet:	1000	20
Drain Cooler:	5000	30
Heater:	5000	30
Feedwater Pump:	1000	2
Gland Condenser:	5000	30

$$\lambda c_k := \frac{1}{MTTFC_k} \qquad \mu c_k := \frac{1}{MTTRC_k}$$

$$AC_k := \frac{\mu c_k}{\mu c_k + \lambda c_k} + \frac{\lambda c_k}{\lambda c_k + \mu c_k} \cdot e^{-(\lambda c_k + \mu c_k) \cdot T}$$

	AC_k
Condensate Pump:	0.998004
Steam Jet:	0.980392
Drain Cooler:	0.994036
Heater:	0.994036
Feedwater Pump:	0.998004
Gland Condenser:	0.994036

B. Availability of each block:

$$AB_1 := 3 \cdot (AC_1)^2 - 2 \cdot (AC_1)^3$$

$$AB_2 := 3 \cdot (AC_2)^2 - 2 \cdot (AC_2)^3$$

$$AB_3 := AC_6$$

$$AB_4 := 3 \cdot (AC_3)^2 \cdot (AC_4)^4 - 2 \cdot (AC_3)^3 \cdot (AC_4)^6$$

$$AB_5 := 3\cdot\left(AC_4\right)^6 - 2\cdot\left(AC_4\right)^9$$

$$AB_6 := 2\cdot AC_5 - \left(AC_5\right)^2$$

$$AB_7 := 3\cdot\left(AC_4\right)^2 - 2\cdot\left(AC_4\right)^3$$

	AB_j
Condensate Pumps Block:	0.999988
Steam Jet/Air Ejectors Block:	0.998862
Steam Gland Condenser Block:	0.994036
Low Pressure Heaters Block 1:	0.999062
Low Pressure Heaters Block 2:	0.999062
Feedwater Pumps Blcok:	0.999996
High Pressure Heaters Block:	0.999894

C. Availability of Feedwater System:

$$AS_1 := \prod_j AB_j \qquad AS_1 = 0.990922$$

4. Calculation of Availability of each System(Except Feedwater System):

Mean Time To Failure of each system: $MTTFS_n$ $\quad n := 2..7$

Mean Time To Repair of each system: $MTTRS_n$

	$MTTFS_n :=$	$MTTRS_n :=$
Steam generator:	10000	60
Turbine Generator:	500	15
Condensor:	5000	30
Reactor Coolant Pump:	2500	20
Reactor:	5000	10
Pressurizer:	5000	20

$$\lambda s_n := \frac{1}{MTTFS_n} \qquad \mu s_n := \frac{1}{MTTRS_n}$$

$$AS_n = \frac{\mu s_n}{\mu s_n + \lambda s_n} + \frac{\lambda s_n}{\lambda s_n + \mu s_n} \cdot e^{-(\lambda s_n + \mu s_n) \cdot T}$$

	AS_i
Feedwater System:	0.990922
Steam generator:	0.994036
Turbine Generator:	0.970874
Condensor:	0.994036
Reactor Coolant Pump:	0.992063
Reactor:	0.998004
Pressurizer:	0.996016

5. Availability of whole plant:

$$A_{plant} = \prod_i AS_i$$

$$A_{plant} = 0.937442$$