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Report on Internship Project: Risk-Informed Cost Reduction in Nuclear Power Plants

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Changing the World's Energy Future

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Idaho National Laboratory

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Summer Internship Project Report

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I. Introduction

I.1. Problem Identification

Several Nuclear Power Plant (NPP) operators in USA have announced to close their plants despite there are remaining years on their operating licenses. These NPPs along with their capacity is shown in Figure 1. Reference [1] identified that the cause of these closures is because the plant operators suffer financial losses. Figure 2 shows the gap between NPP revenue and their electricity generation costs. Approximately 80% of USA NPPs would have undergone financial losses if they were situated in a deregulated electricity market.

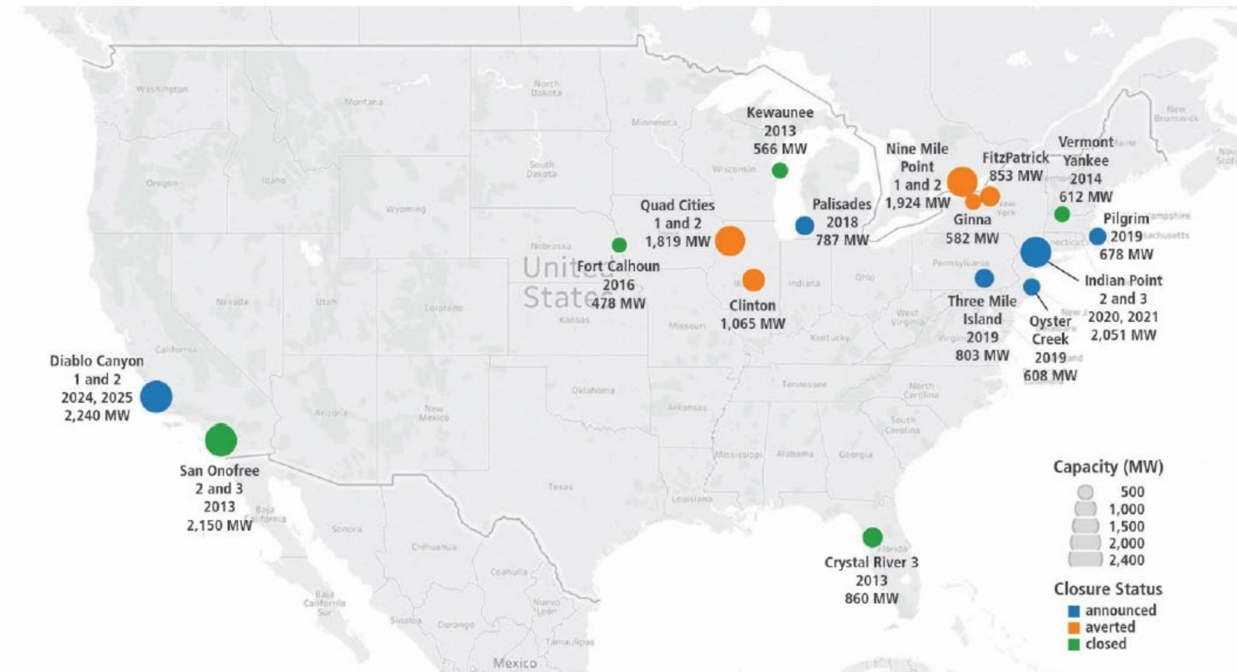

Figure 1. Location of Nuclear Power Plant Retirements [2]

In a deregulated market, electricity generators are independent entities separate from the transmission companies and Independent System Operator (ISO) which manages the market. NPPs in this market are termed merchant NPPs, and their profitability is determined solely from electricity generation revenues. Meanwhile, regulated and public power nuclear units' profitability is determined by the regulatory process in place for each unit. Due to the complexity of differentiating each regulated and public power NPP's regulations, Figure 2 was developed with a simple assumption which disregards these regulations. Therefore, the Figure indicates that 36 NPPs are at an immediate risk of retiring early to stop losses, while 27 units will likely to follow in the long run.

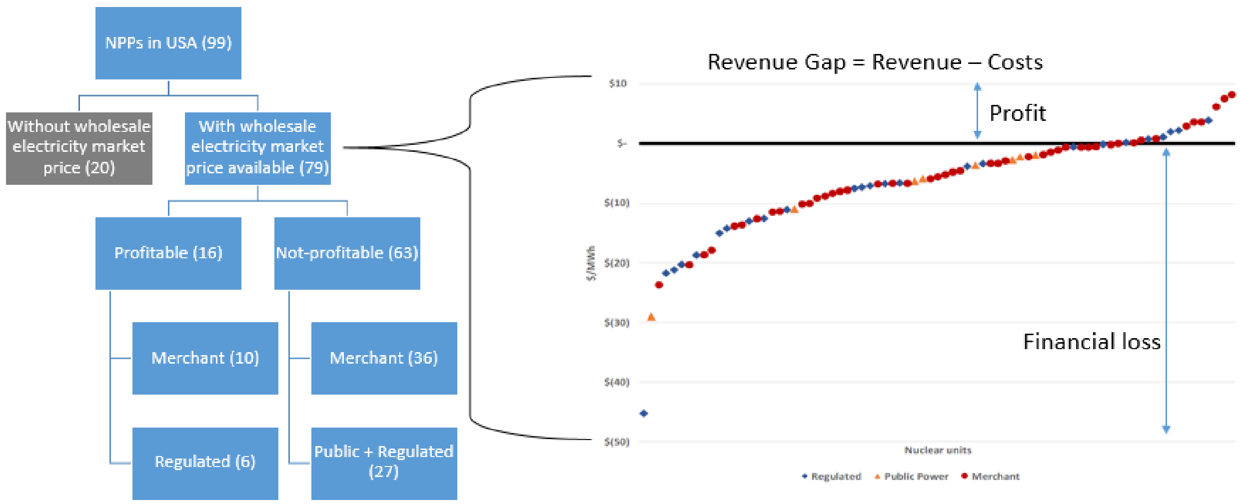

Figure 2. Revenue Gap of NPPs in USA

To determine the causes of NPP financial loss, consider the electricity trade mechanism in a deregulated market illustrated in Figure 3. Resellers such as ISOs or Regional Transmission Organizations (RTOs) manage the electricity supply-demand balance. Wholesale transactions between generators and resellers occur in different time period categories. The Capacity market transactions occur typically 3 years before the actual year in which electricity is generated, to secure sufficient supply capacity to meet the projected annual demand. Within the 3 year period, Incremental capacity transactions occur to accommodate the transfer of settled Capacity obligations from one generator to the other, for example if a generator cannot produce electricity due to an outage. Within the delivery year, daily day-ahead transactions occur to prevent price volatilities. Real-time transactions occur to fine-tune the preceding day-ahead supply and demand balance. Reserve energy transactions are also conducted in a day-ahead and real-time market. Generators participate in the reserve market by selling their capability to adjust electricity production to demand fluctuations. Baseload generators, which are limited to load-follow the grid either by technical capability or regulations, may not be able to take the full advantage of the reserve market as an additional source of revenue.

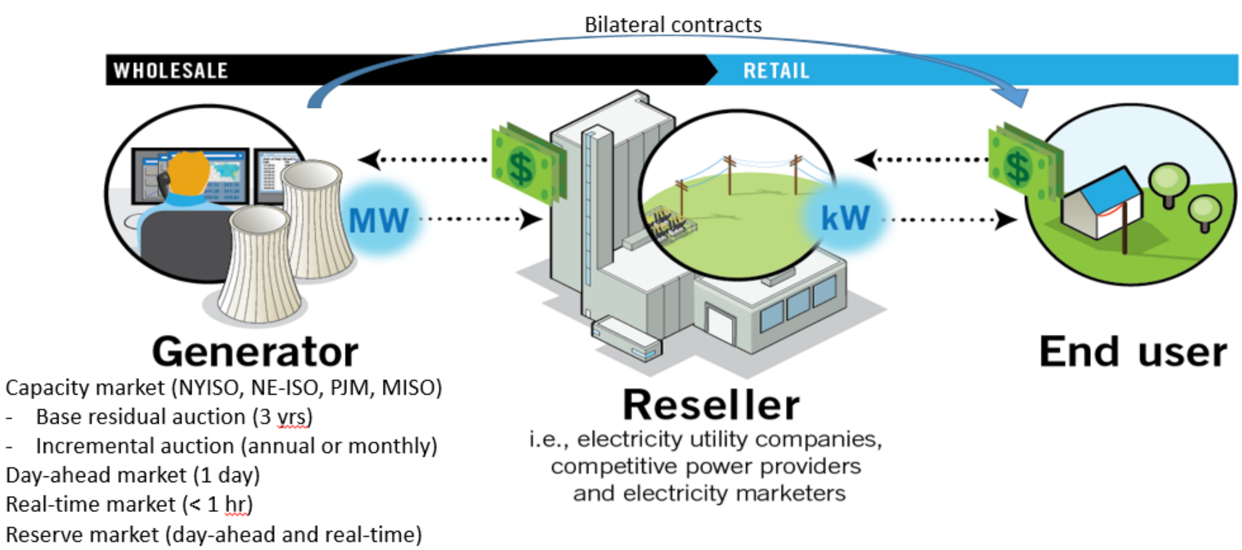

Figure 3. Electricity transactions in a deregulated market

Wholesale electricity transactions take place in auction-type settlements. Consider the Day-ahead market as shown in Figure 4. In this market, generators bid their electricity supplies and selling prices. ISO/RTO sorts the supplies ascendingly based on the prices. For an expected demand D, the electricity price is determined by the marginal generator at P. Infra-marginal supplies to the left of D will be dispatched. Each infra-marginal generator will receive a revenue as formulated in Eq (1). The revenue is directly proportional to electricity price, which is a function of demand. As the demand decreases, for example to D' or D'', the electricity price and generators' revenues also decrease. This demand reduction was observed in the PJM grid as shown in Figure 5.

$$Revenue\ (\$) = Price\ \left(\frac{\$}{MWh}\right) * Production\ (MW) * Time\ (h) \tag{1}$$

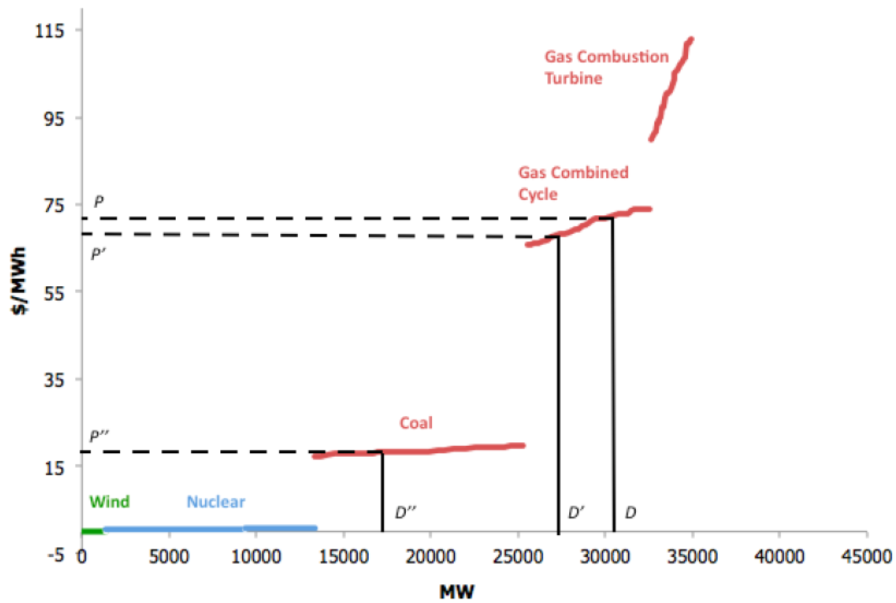

Figure 4. Day-ahead market reflecting 2008 prices [3]

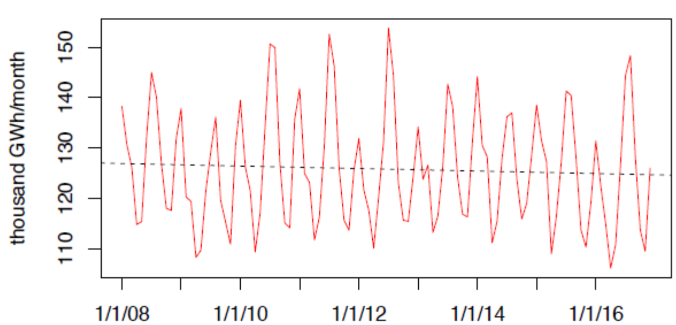

Figure 5. Electricity sale across PJM from 2008 to 2016 [3]

Another cause of NPP financial loss is the increased penetration of Variable Renewable Energy (VRE) such as wind and solar. VREs may be able to bid low since they have negligible generation cost. Tax credits given to VREs can lower their bid even further to negative prices. Therefore VREs typically secure the first priority in electricity generation. Figure 6 shows that increased VRE generation shifts the entire supply curve to the right, or equivalently shifts the demand D to the left compared to Figure 4.

Therefore the electricity price and generators' revenues decrease along with increased VRE capacities. Figure 7 shows that wind energy production has indeed been increasing since 2008.

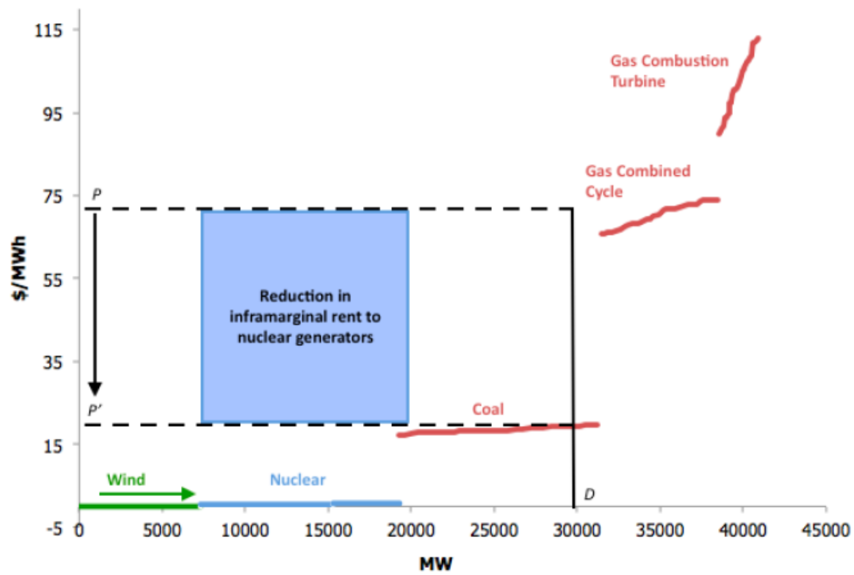

Figure 6. Hypothetical electricity supply curve with increased wind generation [3]

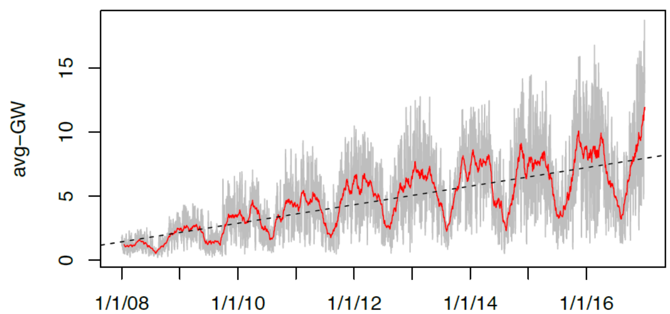

Figure 7. Daily average (grey) and 31-day rolling average (red) wind energy generation in MISO and PJM market regions from 2008 to 2016 [3]

The final identified cause of NPP losses is the decreasing natural gas price. Figure 8 shows the electricity supply curve when natural gas price drops. When the gas-powered generator becomes the marginal generator, a drop in gas price reduces their bid and the electricity price for other generators. Figure 9 shows that natural gas price has indeed been decreasing from 2008 to 2016.

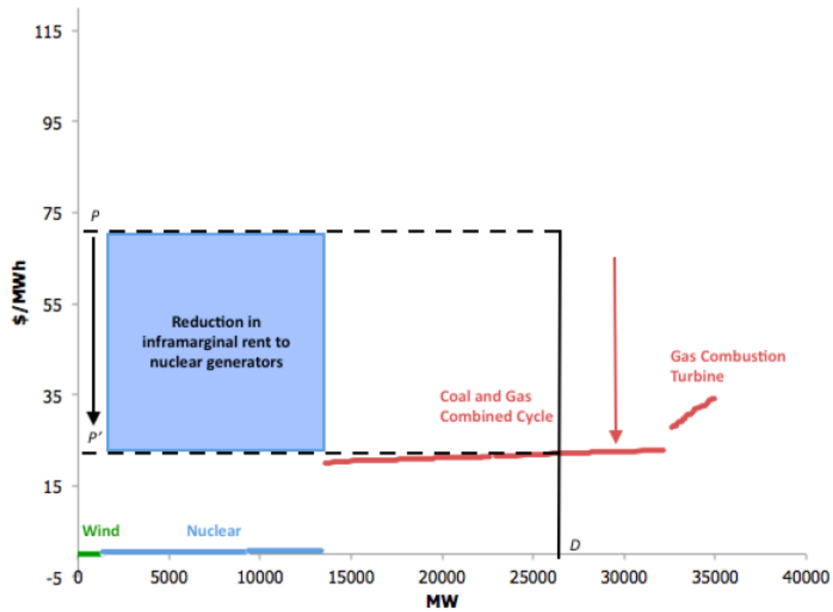

Figure 8. Hypothetical electricity supply curve with reduced gas price [3]

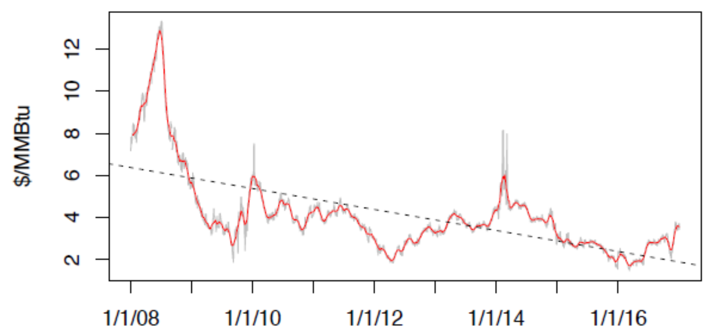

Figure 9. Daily average (grey) and 31-day rolling average (red) natural gas spot market prices at Henry Hub from 2008 to 2016 [3]

I.2. Possible Solutions

A possible solution to NPP financial loss is to provide financial rewards to NPPs for generating carbon-free energy, for example through a Zero Emission Credit (ZEC) [4] in New York and Illinois States. If the New York 2018 ZEC at $17.48/MWh were applied to the NPP revenue gap shown in Figure 2, the percentage of NPPs with a negative profit would decrease from 80% to 12%. This ZEC price was set based on the social cost of carbon [5] and was implemented to achieve the State's goal to reduce greenhouse gas emissions.

The second solution is to adjust NPPs to the increasing growth of VREs and decreasing electricity demand. USA NPPs generally operate in a baseload mode, supplying all of its production capacity to the grid. However with increasing VRE capacities, the entire supply curve may fluctuate daily due to the intermittent nature of VREs. When NPP serves as a marginal generator in a baseload mode and the real-time demand is lower than the day-ahead demand, NPP may need to pay users to absorb the excess production. In certain scenarios, this payment may be compounded by the negative price set by VREs. If NPP adjust its supply to the grid accordingly, these losses may be avoided. Furthermore, NPPs may gain extra revenues from the Reserve market and divert excess steam to energy storage [6]for future sale as shown in Figure 10. In this scheme, NPP is able to bid its day-ahead supply to match a predicted demand and allocate its excess capacity to the reserve market and/or energy storage module. The total revenue in this scenario is given in Equation (2). Reference [7] estimated that NPPs are able to gain up to $17.75 million in gross margin when they operate flexibly. This gain was credited to revenues from the Reserve market and cost savings from fuel elements. Such flexible operation mode has been implemented in the Europe [8]. NPPs in USA are technically capable of operating in a load-following mode either automatically or manually, by adjusting the fission power, dumping excess steam, or adjusting the recirculation flow [9]. Current regulation however limits this capability [10].

$$\begin{aligned} Revenue\ (\$) = & \left[DayAheadPrice \left(\frac{\$}{MWh} \right) * x\ (MW) * Time\ (h) \right] \\ & + \left[DayAheadReservePrice \left(\frac{\$}{MWh} \right) * y_1\ (MW) * Time\ (h) \right] \\ & + \left[RealTimeReservePrice \left(\frac{\$}{MWh} \right) * y_2\ (MW) * Time\ (h) \right] \\ & + Energy\ storage\ z_2\ for\ future\ sale \end{aligned} \tag{2}$$

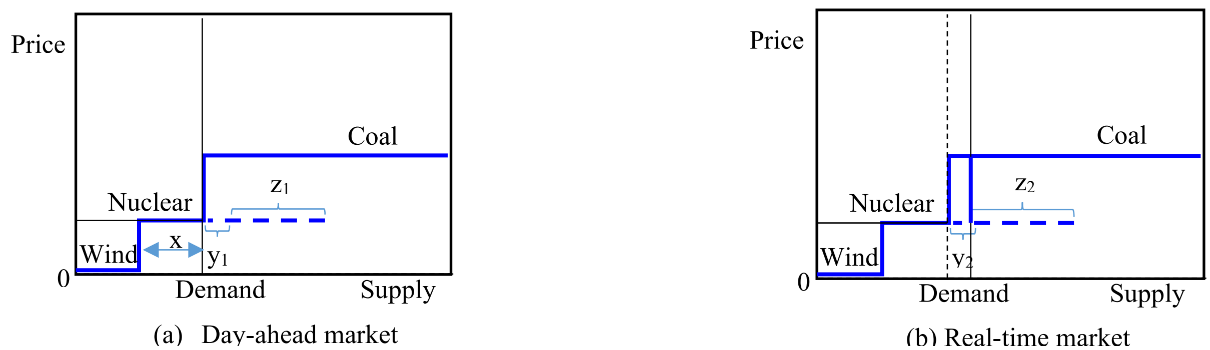

Figure 10. NPP market performance by operating in a flexible mode

The third solution is to reduce NPP operational and maintenance (O&M) costs. Table 1 shows the components of O&M costs for USA NPPs sorted from the most to the least costly components. One way to reduce major cost components, i.e. labor, production taxes, boric acid production, maintenance, and licensing, is to mothball NPPs with financial difficulties temporarily until the market situation improves [11]. A mothballed NPP requires only a minimum number of personnel to maintain and secure the plant. This option however requires a regulatory breakthrough since current regulations in USA does not accommodate mothballing. A regulatory procedure is also required to synchronize mothballed NPPs to the regulatory standards at the time the NPP is revived.

Table 1. Nuclear Annual Operational and Maintenance Costs in USA [12]

Category	**Changes**		**new 2010 $ in thousands**
IMPLAN Descriptor	IMPLAN	NAISC	2010$K
Labour	Labour	Labour	$62,041
Taxes	Taxes	Taxes	$18,260
Other basic inorganic chemical manufacturing	125	325188	$16,476
Architectural and engineering services	369	5413	$13,568
Other Federal Government enterprises	429	NA	$12,623
Other nonmetallic mineral mining	27	21239	$10,823
Maintenance and repair of nonresidential buildings	40	23*	$7,920
Support activities for other mining	30	213113-5	$6,300
All other miscellaneous professional and technical	380	54191, 54193, 54199	$4,763
Misc. electrical equipment and component manufacturing	275	335999	$3,872
Other State and local government enterprises	432	NA	$3,275
Investigation and security services	387	5616	$3,088
Scientific research and development services	376	5417	$2,459
Environmental and other technical consulting servi	375	54162, 54169	$2,407
Power, distribution, and specialty transformer manufacturing	266	335311	$1,766
Waste management and remediation services	390	562	$1,746
Business support services	386	5614	$1,525
Civic- social- professional and similar organizati	425	8134, 8139	$1,436
Facilities support services	385	5612	$1,138
Valve and fittings other than plumbing	198	332911-2, 332919	$1,072
Securities- commodity contracts- investments	356	523	$1,011
Insurance carriers	357	5241	$975
Employment services	382	5613*	$900
Pump and pumping equipment manufacturing	226	333911, 333913	$851
Power generation and supply	31	2211	$812
Management of companies and enterprises	381	55	$786
Warehousing and storage	340	493	$623
Construction of other new structures	36	23*	$554
Other (less than $500,000)			$10,441
Total			$193,510

Another option to reduce O&M costs is by creating flexibility in maintenance programs which can be leveraged to improve O&M efficiency. This approach aligns with the industry's initiative titled "Delivering the Nuclear Promise" which goal is "to identify opportunities to rethink operating practices, improve efficiencies and reduce costs to help keep nuclear power competitive in a changing electricity market—all while advancing safety at the facilities" [13]. Figure 11 shows that electricity generation costs in NPPs can be effectively reduced by reducing O&M cost. Therefore this option is explored in this research.

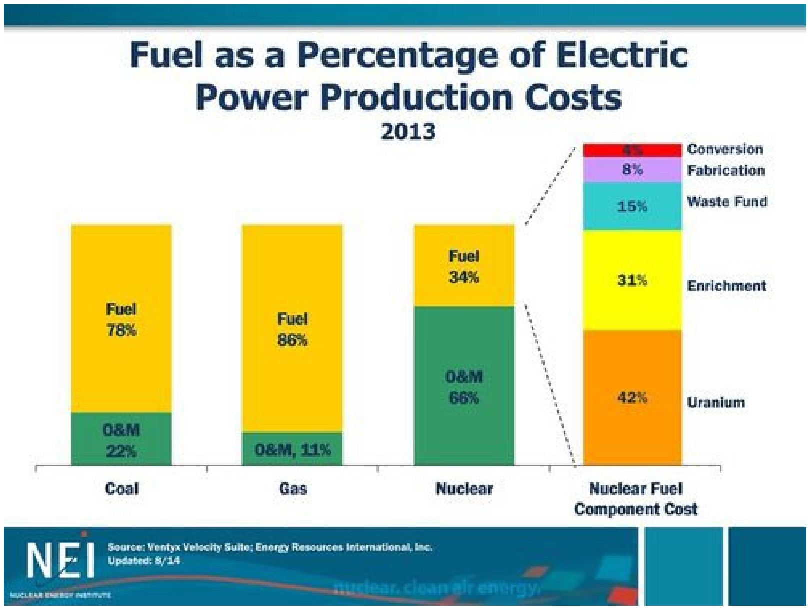

Figure 11. Percentages of Electric Power Production Costs (2013)

II. Methodology

In order to create maintenance flexibility, this research leverages the use of equipment which are portable and compatible with NPP. This approach continues a strategy previously considered within the "Delivering the Nuclear Promise" program [14]. One such category of equipment is already available within the Diverse and Flexible Coping (FLEX) strategy.

FLEX strategy is an additional means to prevent NPP fuel damage due to Station BlackOut (SBO) event as illustrated in Figure 12. FLEX strategy is imposed by Nuclear Regulatory Commission (NRC) to Licensees after the Fukushima-Daiichi accident [15]. This strategy relies on portable equipment which include self-powered pumps, portable generators, batteries, battery chargers, compressors, hoses, couplings, debris clearing equipment, temporary flood protection equipment and other supporting equipment or tools. These equipment are used to provide various safety functions to cool reactor core, maintain containment integrity, and cool Spent Fuel Pool (SFP). Further details on the required safety functions from FLEX equipment for Pressurized Water Reactor (PWR) and Boiling Water Reactor (BWR) are available in Reference [16].

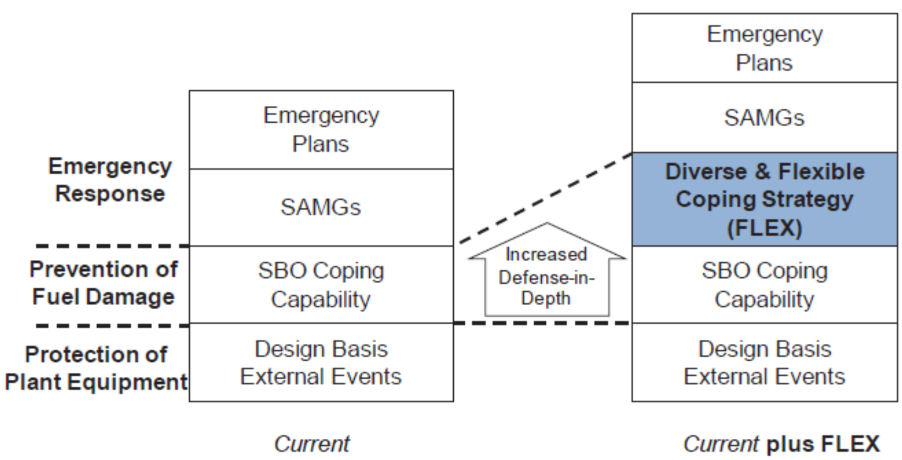

Figure 12. FLEX strategy [16]

The general approach of this research is shown in Figure 13. The first stage is to incorporate existing FLEX strategy into the NPP risk model to expand the plant risk margin [17]. The second stage leverages the portable equipment when not in use in SBO mitigation, to enable a flexible O&M program which may reduce O&M costs [18]. This process is hypothesized to recover some portion of the plant risk margin expanded from the first stage. The plant's end state is expected to have a lower risk compared to the original plant configuration with a reduced O&M cost.

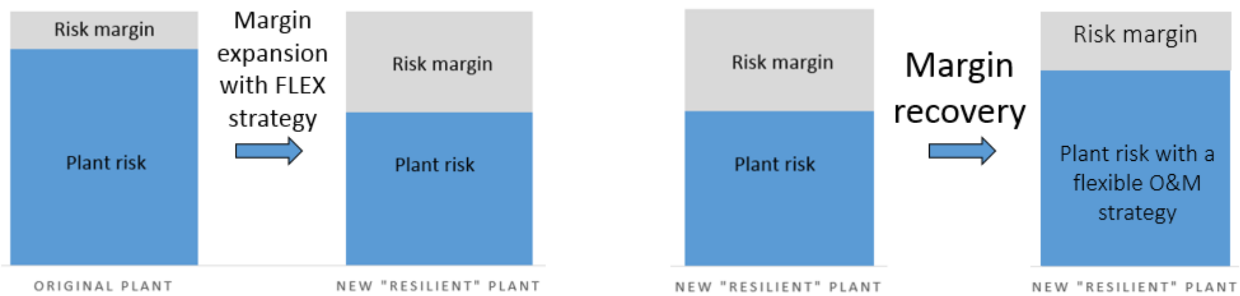

Figure 13. Research approach

Several key guidelines [14] need to be emphasized prior to implementing this proposed approach. The first is that portable equipment should not be used to replace design-basis equipment. Portable equipment however can be implemented in mitigating strategies where they provide a safety function, or be implemented in efficiency strategies to provide improvements in plant operations. Another important guideline is that there should be a well-defined procedure for compensatory actions to return FLEX equipment for use in their original SBO mitigation strategy, when they are deployed for O&M flexibility purposes. This procedure should take into account the required time to deploy, install and start FLEX equipment and the corresponding Human Error Probability (HEP) to perform it. This HEP should be reflected in the plant risk model for SBO event.

II.1. Margin Expansion

II.1.1. Regulatory Challenges

The first stage of this research is to incorporate FLEX into the plant Probabilistic Risk Assessment (PRA) model. Although FLEX strategy has been implemented in NPPs in USA, it has not been sufficiently credited in the plant risk assessment model. Reference [17] provides a guidance to perform this task, which is categorized into three tiers. Tier 1 follows a qualitative approach, Tier 2 uses a semi-quantitative approach with a decision tree, while Tier 3 utilizes a full PRA model to quantify the effect of FLEX strategy to the plant risk. The Nuclear Regulatory Commission (NRC) has assessed this guidance [19] in which they recognize the importance of incorporating FLEX strategy into the PRA models to reflect as-built, as-operated conditions. However, NRC's assessment also noted several issues that need to be addressed to credit FLEX strategy into a PRA model compliant with existing regulations. These issues, among others, include human reliability and equipment reliability quantification.

Guidance [17] describes the insufficiency of current Human Reliability Analysis (HRA) methods to quantify the HEP in human actions required for implementing FLEX strategies. The document further suggests using engineering judgements or equivalent failure probabilities from existing HRA methodologies as surrogates for actions in FLEX strategies. NRC notes however that there are insufficient details in it on using the engineering judgement or surrogates for that purpose. The guide therefore requires further improvements to meet ASME/ANS PRA Standard. NRC also underlined that the technical bases for HEP to initiate mitigating strategies should be submitted for a regulatory review. NRC highlights the need for an acceptable guidance for identifying and assessing pre-initiator human failures in maintenance of FLEX equipment, which may render the equipment unavailable during an event.

NRC emphasized that realistic failure rates for FLEX equipment should be used in lieu of using failure rates of permanently installed equipment. The failure estimates for permanent equipment should not be used because the limited information available for FLEX equipment indicates a potential significant difference to the permanent plant equipment. In order to obtain realistic values for FLEX equipment, plant-specific of generic data should be collected and analyzed using acceptable approaches. Furthermore, NRC recommends the use of currently available Common Cause Failure (CCF) parameters, since these parameters conservatively correspond to higher CCF failure rates of FLEX equipment.

II.1.2. Case Study

Solutions to the aforementioned regulatory challenges are beyond the scope of this study. Nevertheless, this section outlines a case study of margin expansion using FLEX equipment. Figure 14 shows an SBO mitigation event tree for a PWR reactor. There are six sequences leading to core damage in this event tree as shown in Table 2, where FLEX strategy is implemented as an additional mitigation effort in four sequences. The Table indicates that FLEX may reduce plant risk by creating several new scenarios to safely shutdown the reactor. The FLEX strategy in this case study relies on a diverse feedwater injection using a self-powered FLEX pump, or the recovery of turbine-driven pump (TDP) or motor-driven pump (MDP) of Auxiliary Feedwater System (AFW) by using a portable FLEX generator. This generator connects to the existing power bus which also powers the valves required to modulate or cycle secondary-side steam for TDP operation, and charges batteries connected to the bus. Figure 15 and Figure 16 shows the Fault Tree for this strategy. The modified SBO event tree by crediting FLEX strategy is shown in Figure 18. Sequence number 1 in both the original and modified SBO mitigation event tree is considered separately in a General Transients event tree. Event trees aside from SBO, i.e. Steam Generator Tube Rupture (SGTR), Small-break Loss of Coolant Accident (SBLOCA), Medium-break LOCA (MBLOCA), Large-break LOCA (LBLOCA), General Transients, Anticipated Transients Without Scram (ATWS), and Consequential SGTR are given in Appendix I. Plant Core Damage Frequency (CDF) before and after incorporation of FLEX is shown in Figure 17. The Figure shows that FLEX strategy in this study significantly reduces CDF due to SBO event.

Table 2. SBO core damage sequence

Original SBO core damage sequences (Figure 14)		Corresponding SBO sequences when FLEX strategy is implemented (Figure 18)	
Sequence number	End status	Sequence number	End status
3	Core damage	3	OK
		4	Core damage
		5	Core damage
5	Core damage	7	OK
		8	Core damage
		9	Core damage
6	Core damage	10	Core damage
9	Core damage	20	Core damage
10	Core damage	14	OK
		15	Core damage
		16	Core damage
		17	OK
		18	Core damage
		19	Core damage
		20	Core damage
11	Core damage	21	OK
		22	Core damage
		23	Core damage
		24	OK
		25	Core damage
		26	Core damage
		27	Core damage

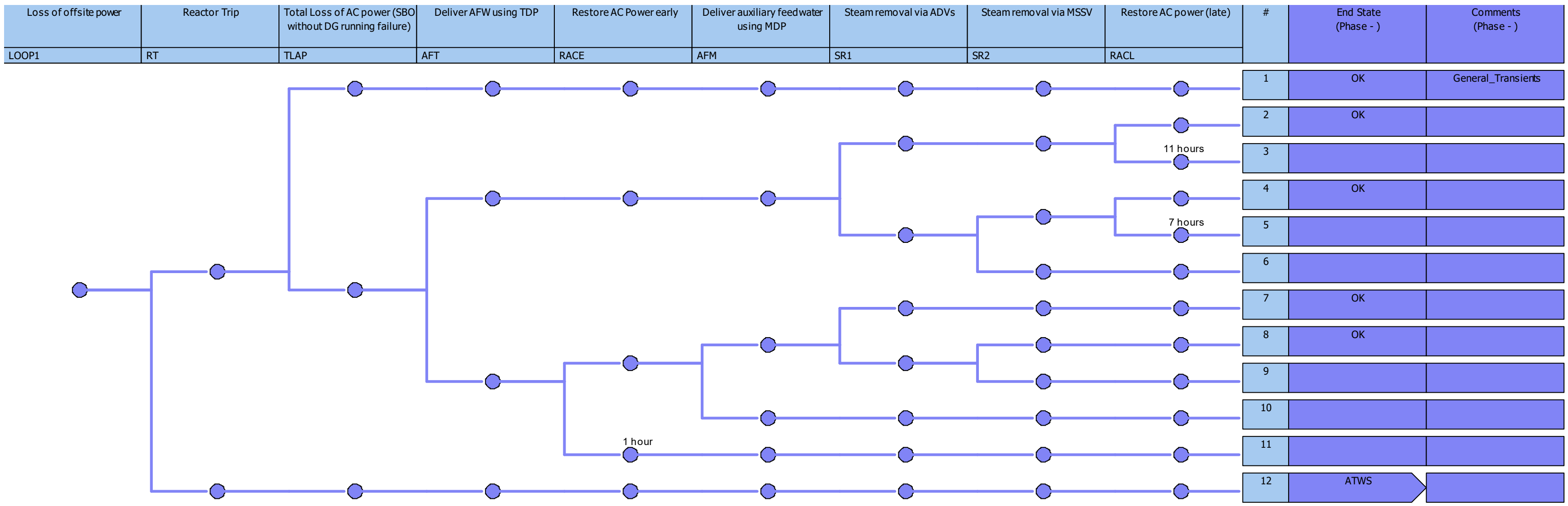

Figure 14. SBO event tree for a PWR reactor

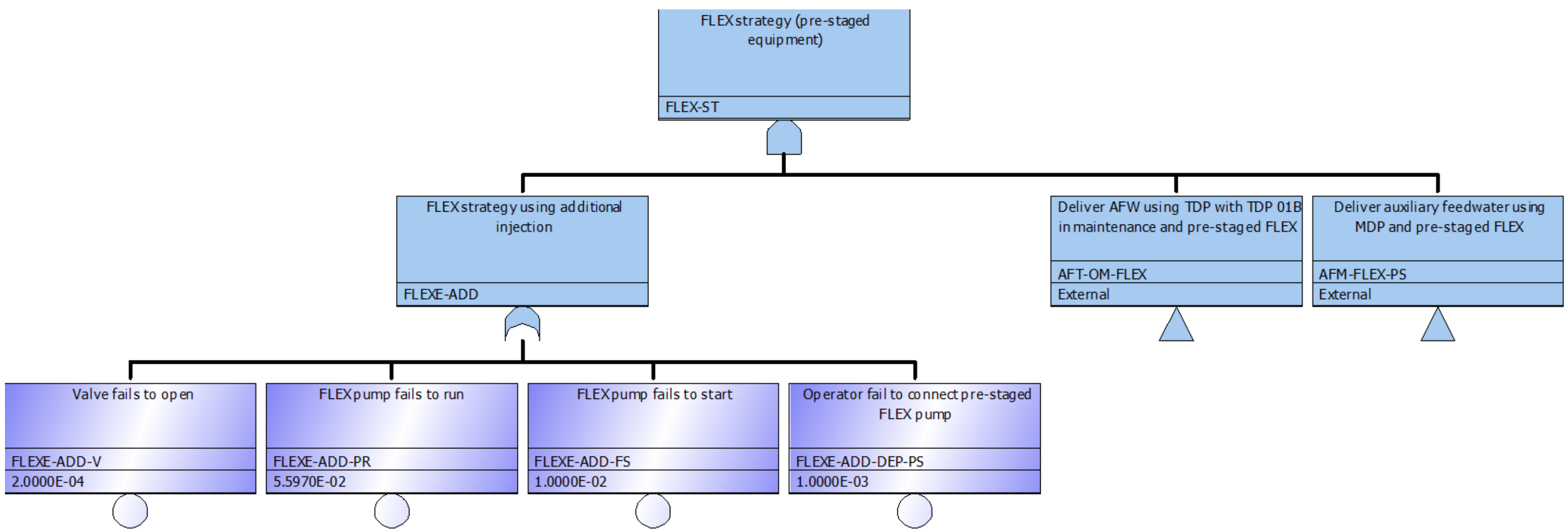

Figure 15. Fault tree for FLEX strategy

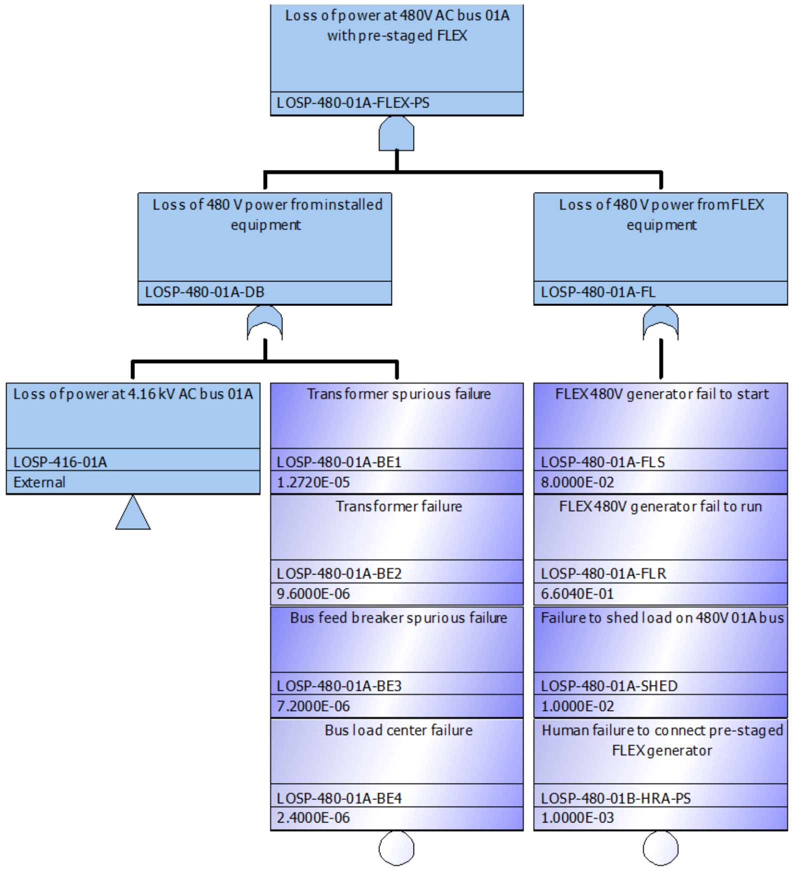

Figure 16. FLEX strategy using portable generator

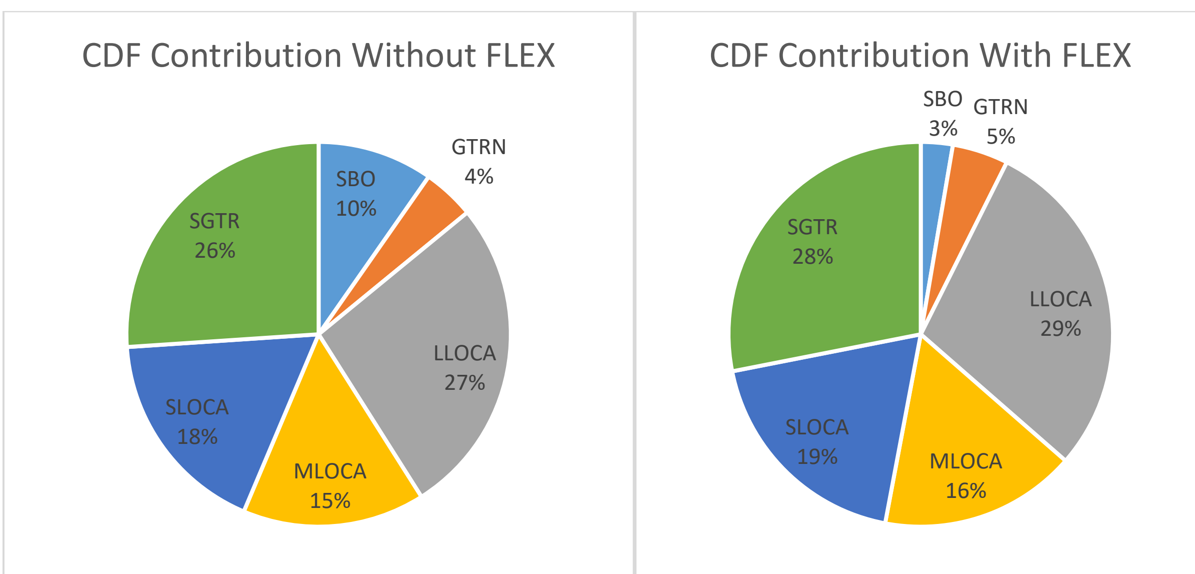

Figure 17. Plant risk change with FLEX introduction

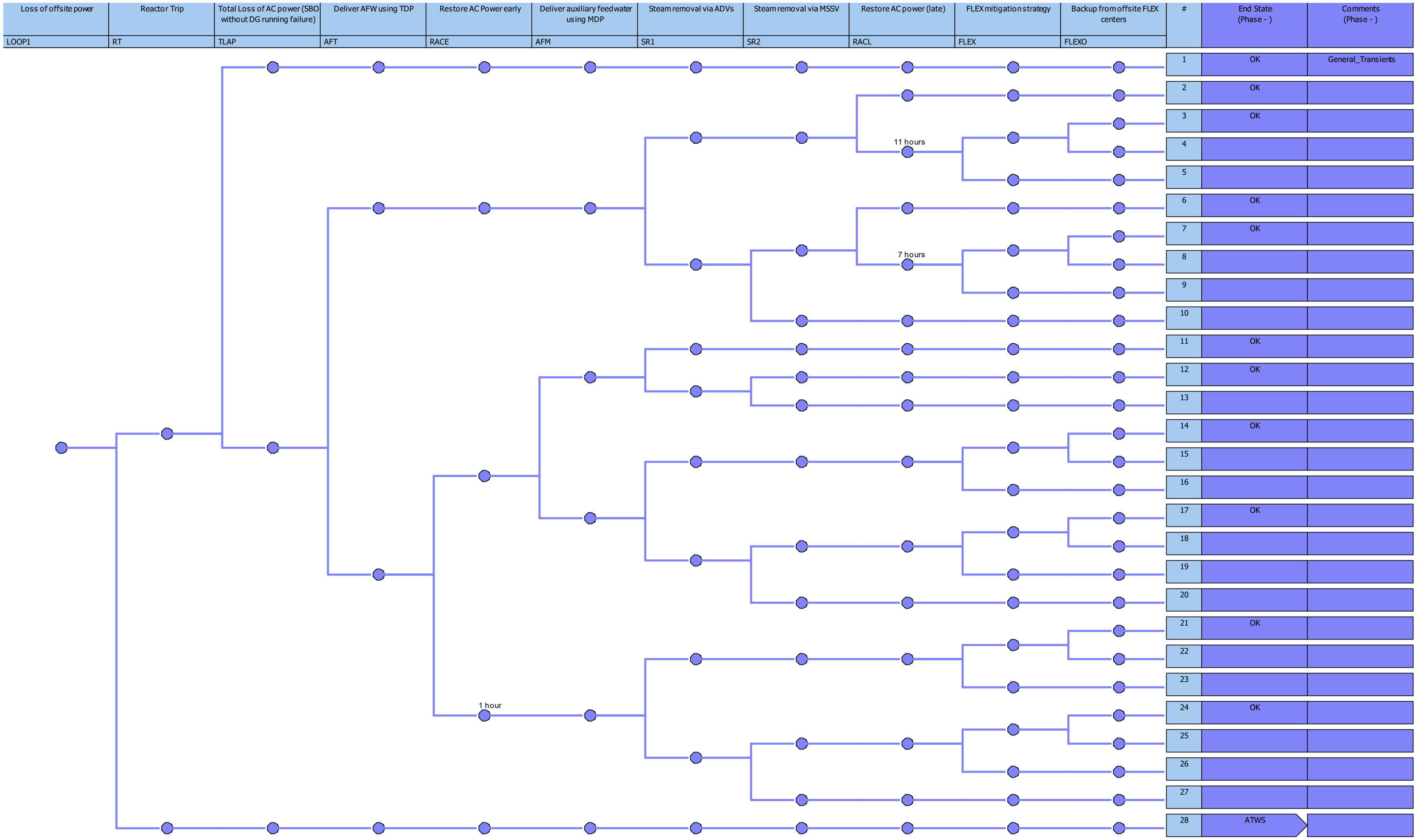

Figure 18. SBO mitigation with FLEX strategy

II.2. Margin Recovery

II.2.1. Online Maintenance

The portability of FLEX equipment can be leveraged to create accident mitigation strategies in order to enable online maintenance of installed equipment. NRC regulation [20] governs the risk acceptance guidelines due to a one-time change in an equipment's Technical Specifications (TS). This regulation can be used to estimate how long an installed equipment can be taken out of service, i.e. Allowed Outage Time (AOT), without shifting to the lower plant operation mode (ex: shutdown) as illustrated in Figure 19. AOT extension using portable equipment may shift components maintenance from refueling outage period to online maintenance. This maintenance scheme may reduce the burden of outage maintenance, allow a more effective outage planning, and increase NPP's capacity factor.

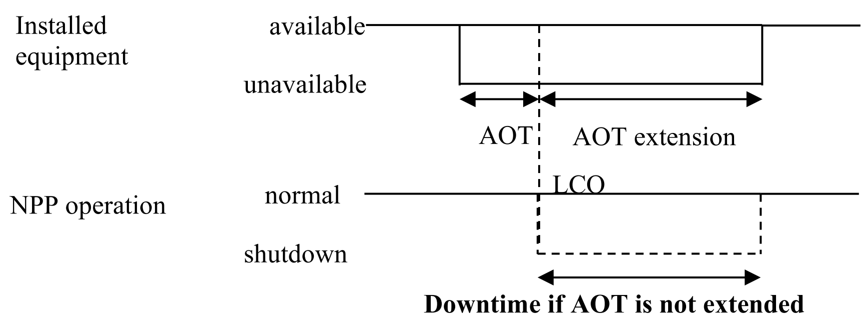

Figure 19. AOT extension

The steps to extend AOT using FLEX portable equipment are as follows:

1. Incorporate FLEX into plant PRA model as explained in the previous section (margin expansion). Generate cutsets and calculate the resulting Level 1 plant risk as CDF_1.
2. Identify the target components which AOT is considered too short and may need to be extended using risk information. Analyze the importance of Basic Events in cutsets from Step 1 using Risk Achievement Worth (RAW) parameter defined in Equation (3). This equation informs the increase in total risk if the component corresponding to the Basic Event is unavailable. The RAW parameter can therefore be compared to the risk acceptance guideline in NRC regulation [20], i.e. Incremental Conditional Core Damage Probability (ICCDP) defined in Equation (5). Shortlist components which RAW parameter exceeds the value given in Equation (6).

$$RAW = \frac{CDF_2}{CDF_1} \quad (3)$$

$$\Delta CDF = CDF_2 - CDF_1 = CDF_1 \times (RAW - 1) \quad (4)$$

$$ICCDP = \Delta CDF \times AOT < 10^{-6} \quad (5)$$

$$RAW > 1 + \frac{10^{-6}}{AOT \times CDF_1} \times 365 \quad (6)$$

3. Render a selected component unavailable for maintenance by setting its Basic Event probability to 1. Generate the PRA cutsets and calculate the resulting plant risk as CDF_2.

4. Identify the safety function(s) to reinforce in order to extend the AOT to the new desired Completion Time (CT). Analyze the importance of Basic Events in cutsets from Step 3 using Birnbaum (Bi) measure defined in Equation (7). This parameter informs the rate of change in total risk as a result of changes to the probability of an individual basic event. Therefore, it can be used to estimate the required change in a basic event probability (P_2), in order to lower the plant risk CDF_2 to a new level CDF_3, which satisfies NRC acceptance guideline for the specified CT. The new basic event probability P_3 is given by Equation (9). Calculate P_3 values for each basic event in the cutsets, and estimate the required failure probability for FLEX strategies to enable these values, i.e. to change P_2 into P_3. This FLEX failure probability is given in Equation (10), assuming that the strategy is implemented as a redundant mitigation strategy to the basic events.
5. Shortlist the FLEX failure probabilities which meets the limits given in Equation (11), and sort them ascendingly. Select the lowest FLEX failure probability from the list, and design the FLEX strategy using existing FLEX equipment to meet the required failure probability. Afterwards, implement this strategy as a redundant mitigation strategy to the corresponding installed safety function. It should be noted that there should be a procedure and sufficient time to return the FLEX equipment to their originally intended SBO mitigation functions.

$$Bi = \frac{\Delta CDF}{\Delta P} = \frac{CDF_2 - CDF_3}{P_2 - P_3} \quad (7)$$

$$CDF_3 - CDF_1 = CDF_2 - CDF_1 - Bi \times \Delta P < \frac{10^{-6}}{CT} \times 365 \quad (8)$$

$$P_3 < P_2 - \frac{(CDF_2 - CDF_1) - \left(\frac{10^{-6}}{CT} \times 365\right)}{Bi} \quad (9)$$

$$P_3 = P_2 \times P_{FLEX-FAIL} \rightarrow P_{FLEX-FAIL} = \frac{P_3}{P_2} \quad (10)$$

$$0 < P_{FLEX-FAIL} < 1 - \frac{(CDF_2 - CDF_1) - \left(\frac{10^{-6}}{CT} \times 365\right)}{Bi \times P_2} \quad (11)$$

Figure 20 illustrates the aforementioned steps to extend AOT. Step 1 sets the baseline plant risk CDF1. Step 3 increases the plant risk to CDF2. The ICCDP parameter given in Equation (5) is a product of delta CDF and AOT. Step 5 reduces the plant risk from the supposed CDF2 to CDF3, thereby lowering the delta CDF. This lower delta CDF enables AOT to be extended while complying with the ICCDP guideline of 1E-6.

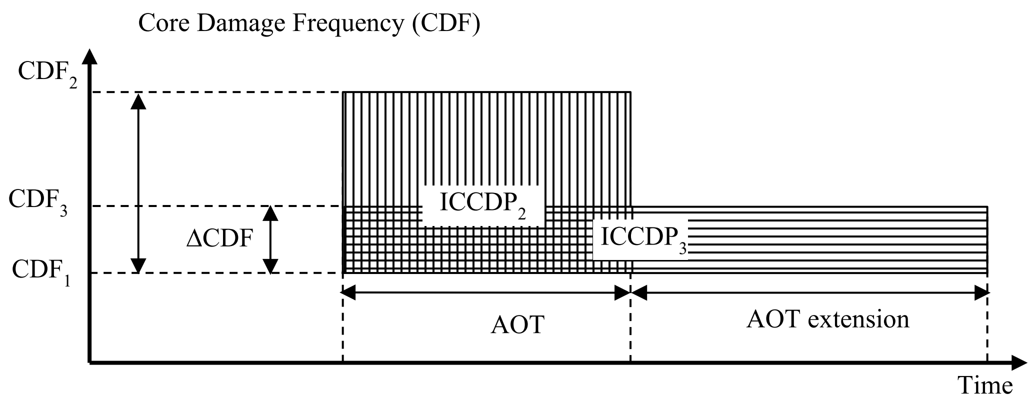

Figure 20. AOT extension in compliance to allowed risk acceptance guideline

Licensees may implement the AOT extension permanently if the change in plant risk complies with the risk acceptance guideline in Regulatory Guide 1.174 [21]. In such case, the FLEX strategy in Step 5 should follow the following equations:

$$CDF_3 - CDF_1 = CDF_2 - CDF_1 - Bi \times \Delta P < 10^{-6} \quad (12)$$

$$0 < P_{FLEX-FAIL} < 1 - \frac{(CDF_2 - CDF_1) - (10^{-6})}{Bi \times P_2} \quad (13)$$

II.2.2. Case Study

An example of AOT extension in a 1000 MWe PWR plant using the steps described in the previous subsection is as follows:

1. CDF_1 with the incorporation of FLEX strategy as shown in Figure 18 was at the order of 1E-5.
2. AOT less than 5 days was considered too short in this example. Therefore the minimum RAW calculated with Equation (6) was 4.25. Approximately 160 basic events were found having RAW values above 4.25, including valve failures and turbine-driven pump (TDP) failures. TDP with RAW values ranging from 4.3 to 4.5 was selected for further investigation, since a TDP maintenance may take longer than 5 days.
3. The fail-to-start probability of a TDP was set to 1, which resulted in a CDF_2 of 1E-4. This risk increase corresponded to an AOT of 4 days.
4. It was considered to extend the AOT to a total of at least 10 days. The safety functions which may be improved with FLEX strategies, as identified by Birnbaum importance, were emergency power using installed Emergency Diesel Generators (EDGs) and decay heat removal through the other Steam Generator (SG) where the TDP is available. Since the FLEX equipment in this case study as shown in Figure 15 and Figure 16 do not include a 4.16 kV diesel generator to reinforce installed EDGs, the selected FLEX strategy was to provide a diverse means of supplying feedwater through the intact SG. The required failure probability value (P_3) for this combined feedwater supply means was less than 4E-4.
5. The failure probability for the FLEX strategy in order to achieve the P_3 value should be less than 2.8E-2. This was achieved by pre-staging on-site FLEX equipment as shown in Figure 21 as a redundancy to existing AFW system, and pre-coordinating with off-site FLEX centers. These preliminary actions may lower the chance of human failure to activate and sustain FLEX equipment as a backup to provide feedwater. The resulting CT with this strategy was found to be 10 days.

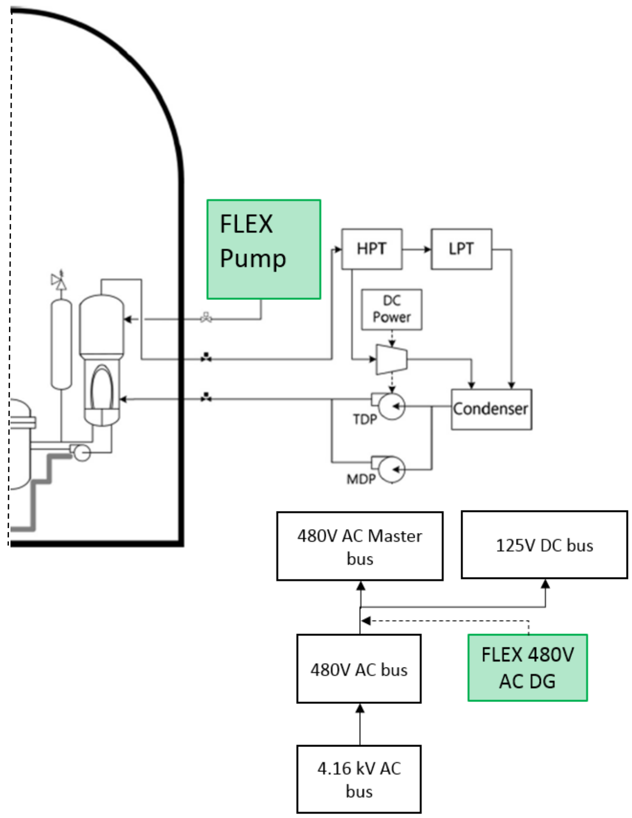

Figure 21. Pre-staging secondary side FLEX equipment

II.2.3. Refueling Outage Maintenance

FLEX equipment may also be utilized to provide maintenance flexibility during refueling outage [22]. One example is shown in Figure 22, where a portable FLEX pump is deployed to replace the High Pressure Safety Injection (HPSI) pump in refilling the Safety Injection Tank (SIT) during an outage. This strategy may reduce the wear and tear of the HPSI pump, and makes it available for maintenance. Another example is shown in Figure 23, where a portable FLEX generator is used to power the spent fuel pool pump. A self-powered FLEX pump is additionally staged as a redundant backup pump to further reduce risks. This strategy allows maintenance to be conducted on the electrical bus.

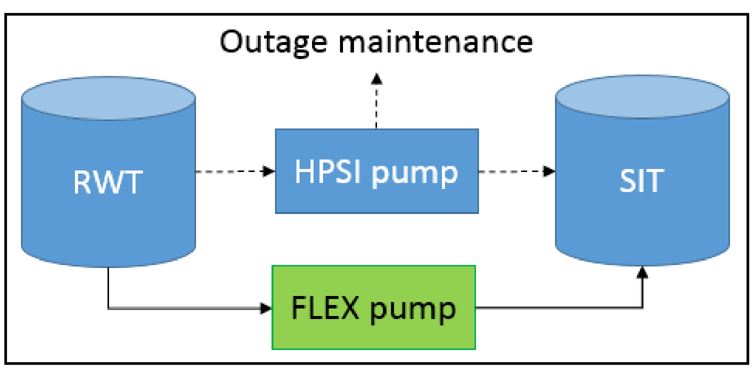

Figure 22. FLEX pump to refill SIT during refueling outage

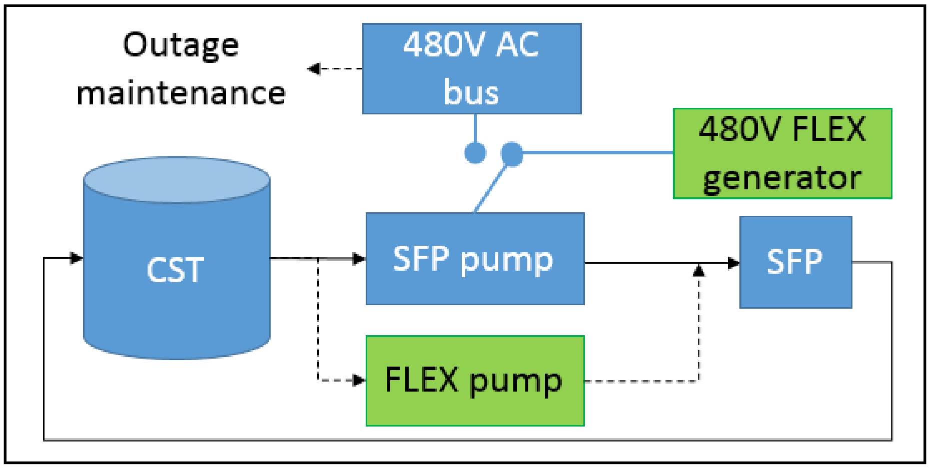

Figure 23. FLEX generator and pump used to cool spent fuel pool during outage

II.3. Outcome

Figure 24 shows the possible outcome of implementing FLEX strategy to reduce plant risk and enable maintenance flexibility. The expected plant unavailability due to Design Basis Events (DBEs) is expected to decrease due to the inclusion of FLEX strategy into the plant PRA model. Incidental plant unavailability due to Limiting Condition of Operations (LCOs) may be reduced because of AOT extension using FLEX strategies. This AOT extension may also enable some of the maintenance routines in the refueling outage period to be shifted to online maintenance. The reduction of outage maintenance tasks may in turn reduce the outage workload and allows for a better outage planning, which reduces the outage duration.

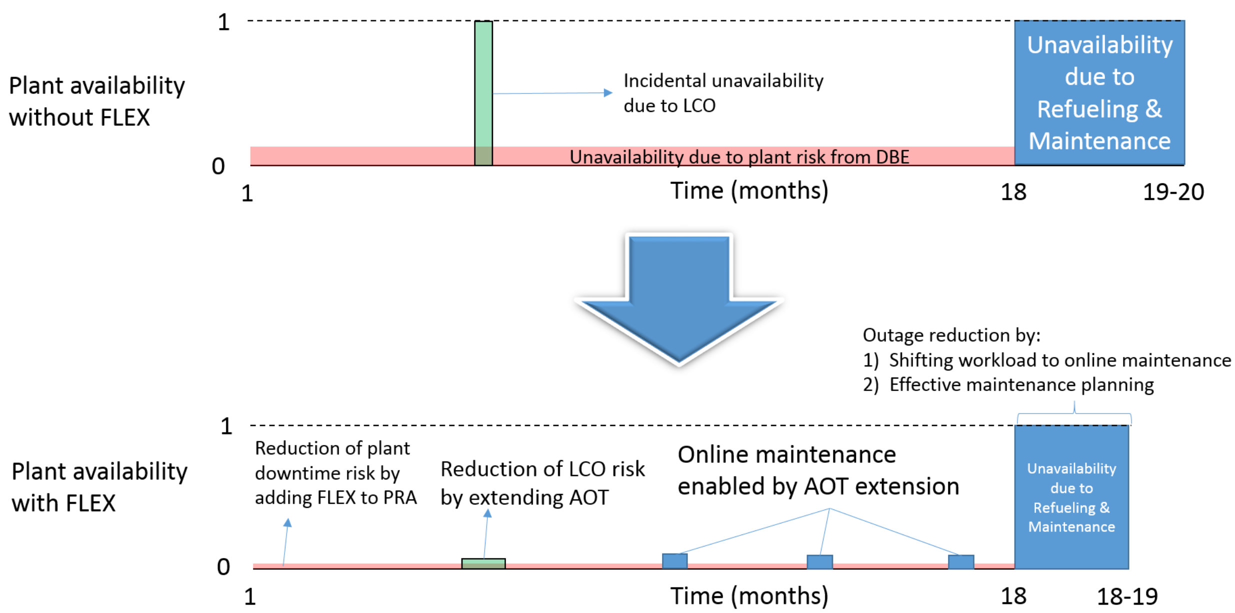

Figure 24. Expected Outcome

Figure 25 shows the various possible scenarios that may happen during a maintenance [23]. A maintenance may be planned or unplanned due to unpredicted faults discovered during routine testing or online monitoring. Both scenarios may require a completion time exceeding AOT. When this happens, Licensees either file a Notice of Enforcement Discretion (NOED) to the NRC, or shutdown the plant. Both options incur costs and/or a loss of revenue. This O&M costs may be averted by extending AOT using FLEX equipment. Furthermore, the extended AOT may allow maintenance activities to be conducted thoroughly, with a better quality compared to a "rushed" maintenance within a limited AOT. In that sense, this approach reduces the chance for a future equipment fault and a costly unplanned maintenance.

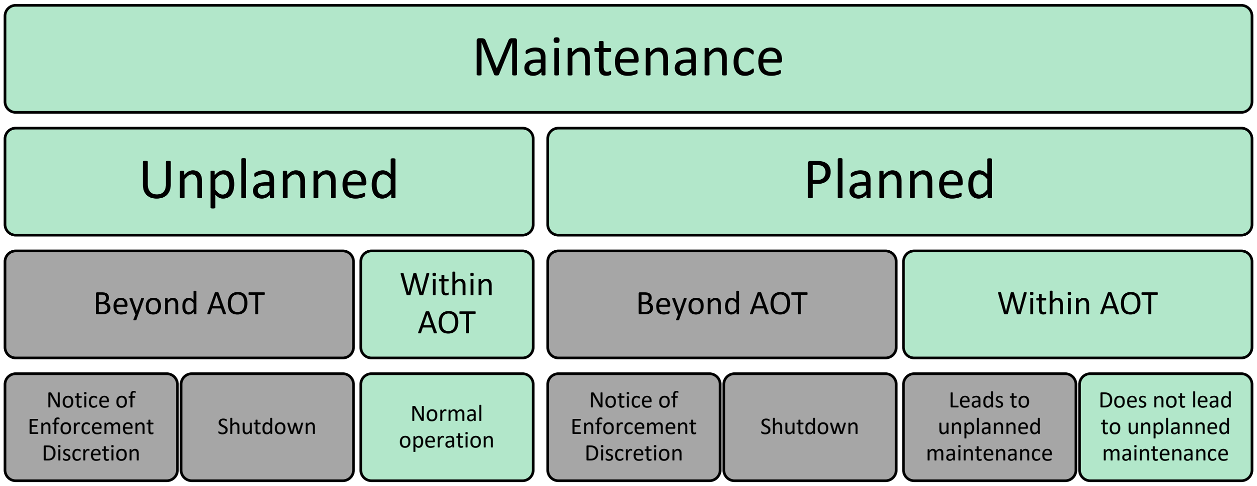

Figure 25. Expected maintenance scenarios

III. Conclusion

The benefits of a flexible O&M program for the industry are:

1. Little to none additional capital investments, because FLEX portable equipment are already available at NPP sites.
2. Reduced maintenance cost as suggested by Figure 25.
3. Increases profitability through an increased capacity factor and a reduced maintenance cost.
4. May help to avoid premature closures of NPPs.

Meanwhile, the regulator (NRC) may also have interests in the application of the proposed risk-informed cost reduction approach as follows:

1. The availability of a more realistic risk estimates which reflect as-built, as-operated conditions of current NPPs.
2. The increased motivation for Licensees to mature their Risk-Informed Application capabilities by incorporating new technologies and/or strategies.

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APPENDIX I

EVENT TREES USED IN CASE STUDY

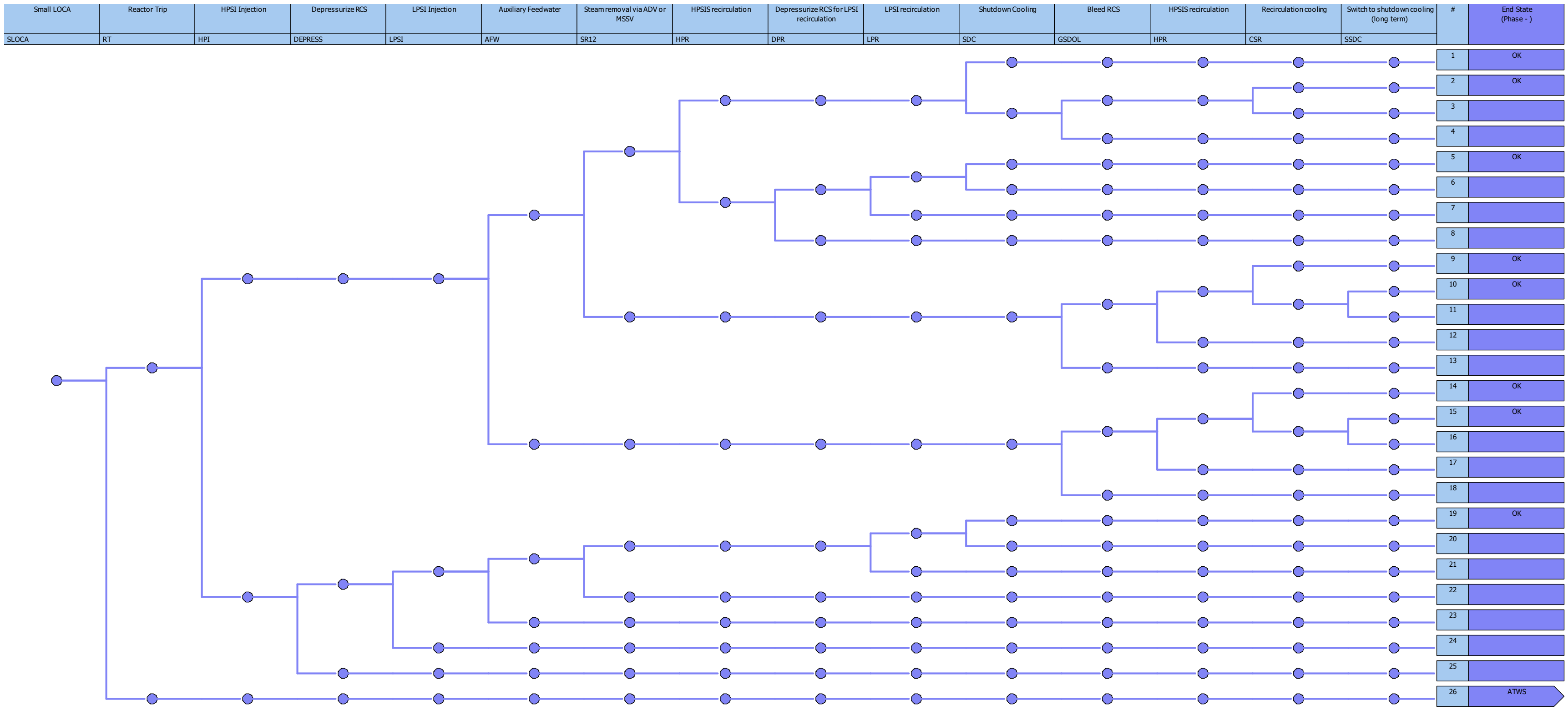

Figure 26. Small Break LOCA

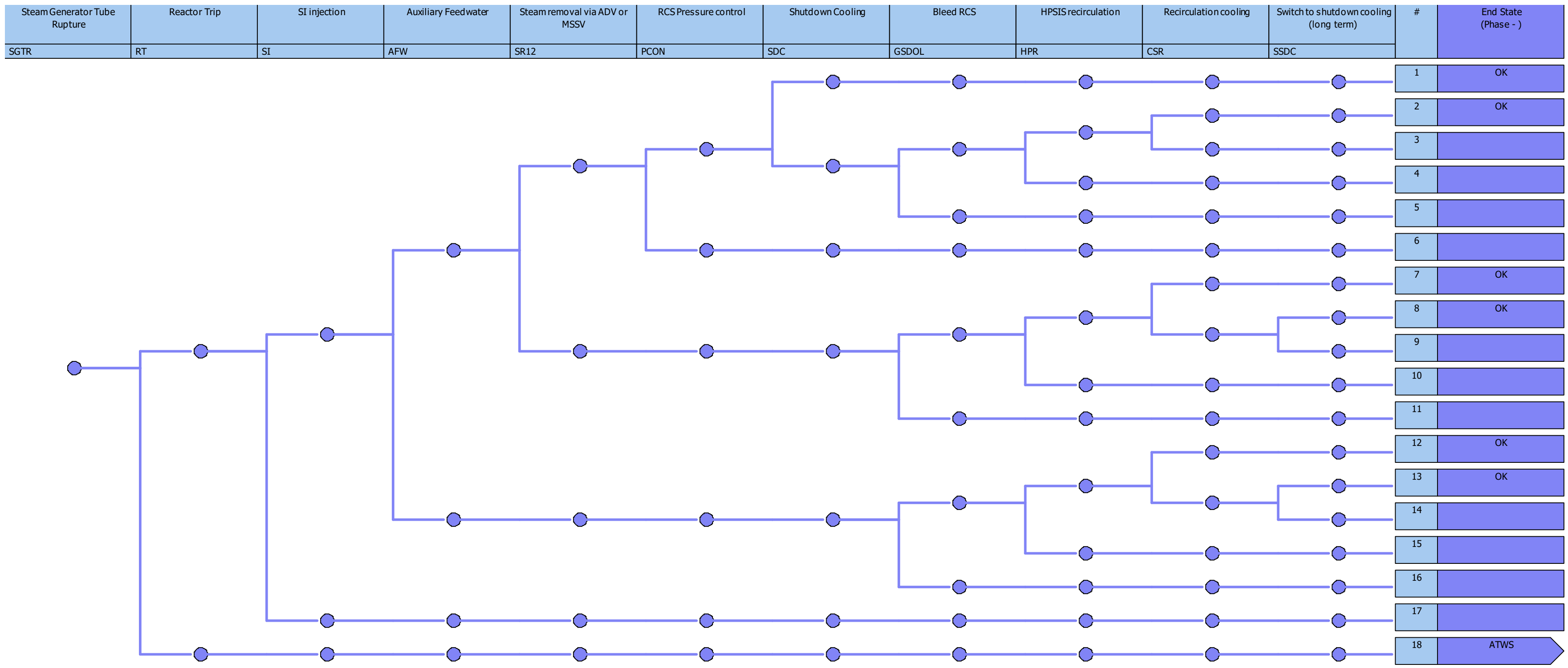

Figure 27. Steam Generator Tube Rupture

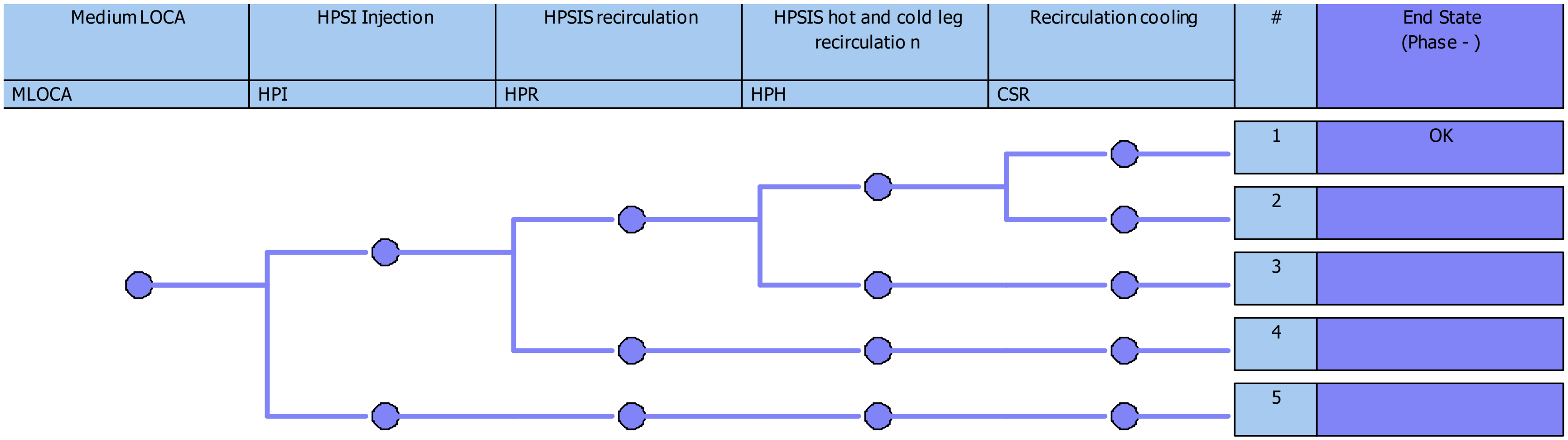

Figure 28. Medium Break LOCA

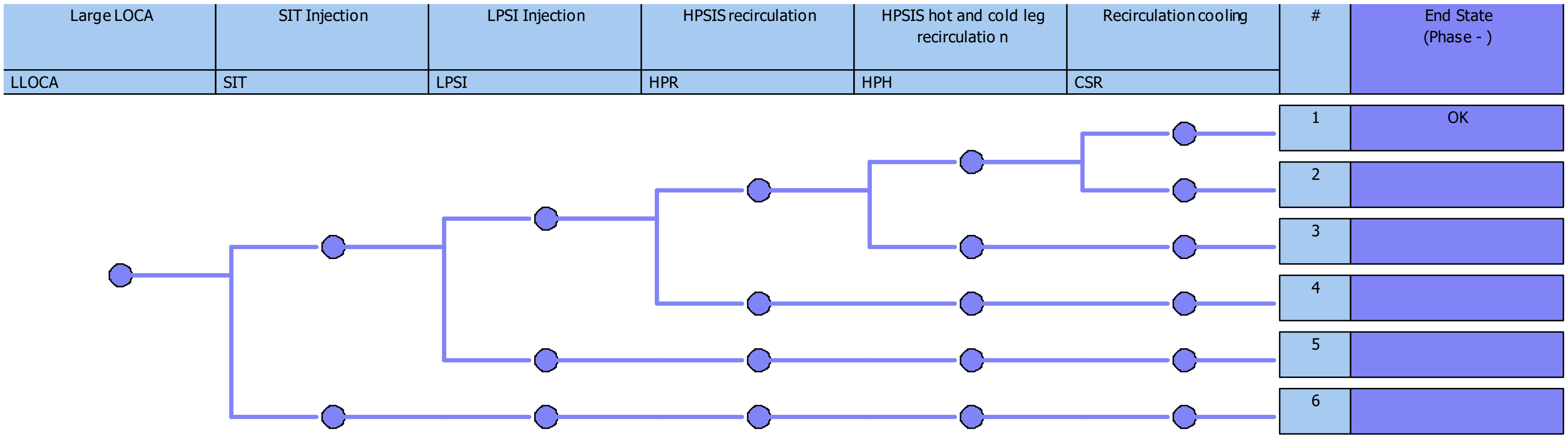

Figure 29. Large Break LOCA

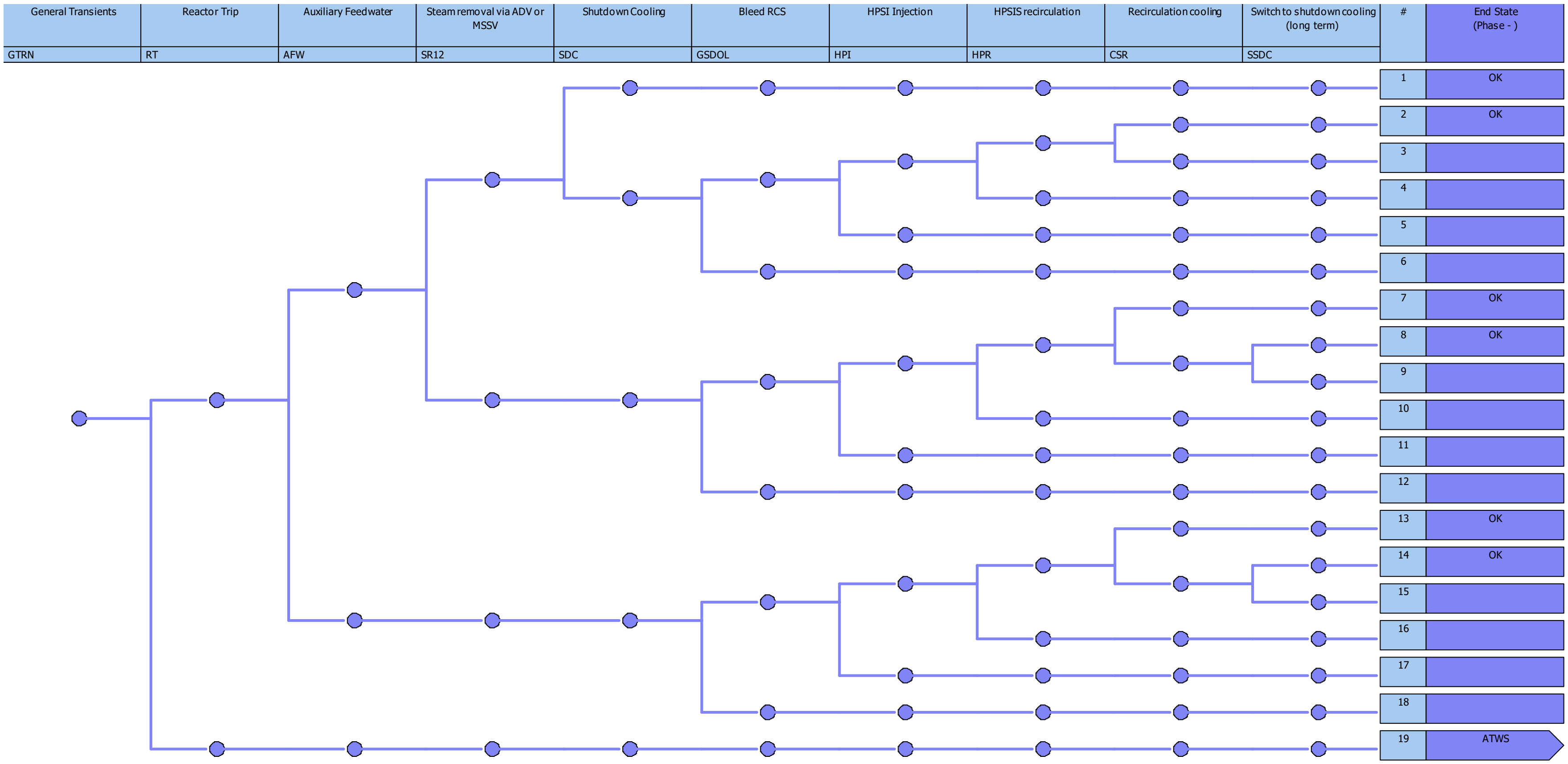

Figure 30. General Transients

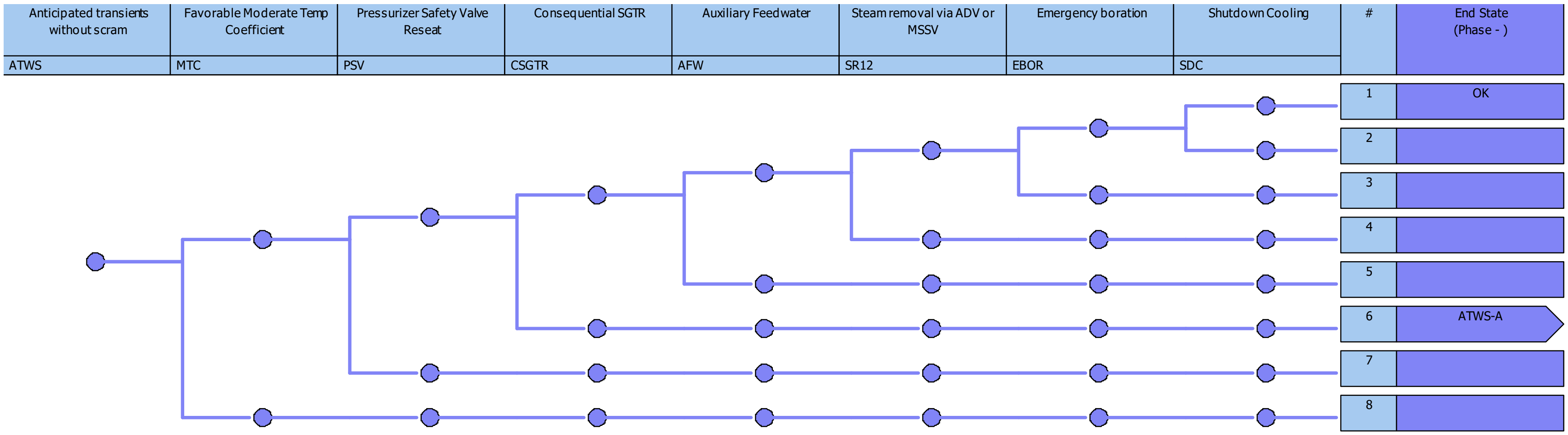

Figure 31. Anticipated Transients Without Scram

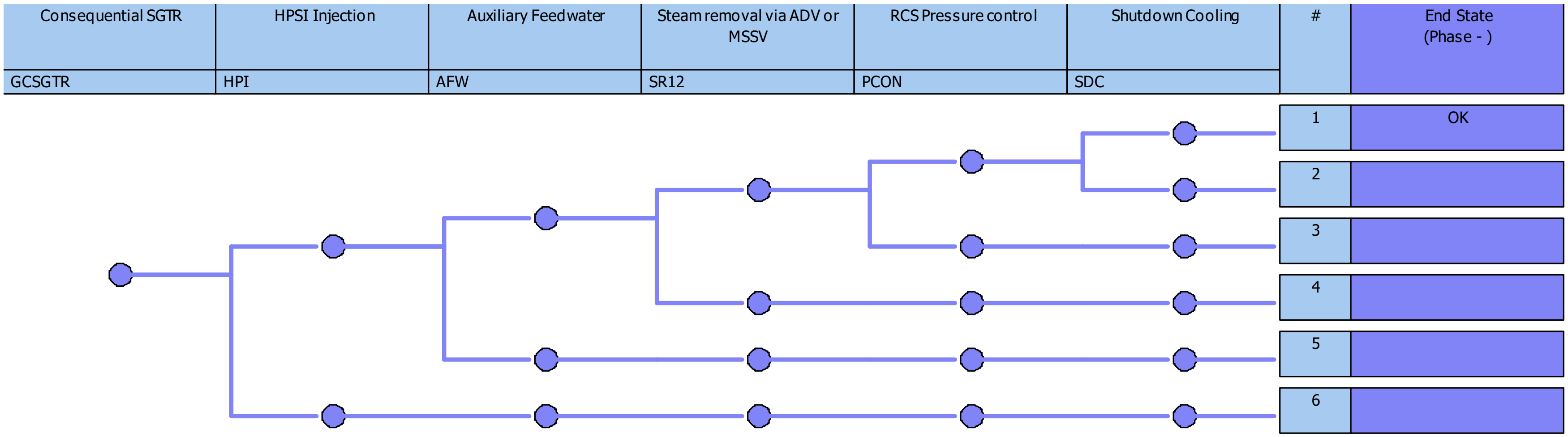

Figure 32. Consequential SGTR