Heat Balance Model Analysis and Equipment Assessment for 30% Thermal Extraction from a Nuclear Power Plant

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1. PURPOSE

As non-dispatchable renewables, predominantly wind and solar, continue to penetrate U.S. energy markets, economic and capability challenges are becoming increasingly prevalent for traditional baseload generators, such as nuclear power plants. These pressures have led to decreased efficiencies and closures for nuclear plants which are vital to meeting national decarbonization goals. In an attempt to maximize efficiency and maintain the existing nuclear fleet, new ways to integrate energy systems are being sought after. One of the focuses of the United States Department of Energy's (DOE) Light Water Reactor Sustainability (LWRS) program is to explore the diversification of light-water reactor (LWR) revenue streams through the Flexible Plant Operation and Generation (FPOG) Pathway. The utilization of nuclear plant steam for direct thermal applications includes hydrogen generation, district heating, thermal storage, and industrial processes. Steam utilization can help increase nuclear plant efficiencies and economics while providing a low-carbon solution for thermal power users. This report assesses the impacts of high levels of thermal extraction on a generic nuclear plant design to determine feasible extraction limits.

2. SCOPE

This work develops a detailed PEPSE heat balance model for a generic nuclear power plant and evaluates the impacts of 30% thermal extraction on the nuclear plant. Plant transients due to startup and shutdown of the thermal extraction system will be addressed, along with impacts to the main steam bypass and final feedwater temperature. Extraction effects on plant equipment, including the high- and low-pressure turbines, main condenser, drain systems, feedwater heaters, and extraction steam are then assessed.

3. MODEL DESIGN

3.1. REFERENCE PLANT

3.1.1. Plant Design

The reference plant modeled for this report is based on 4-loop Westinghouse pressurized water reactor (PWR) design. In a PWR, high-pressure water passes through the reactor core, where it is heated by thermal energy created by nuclear fission. This primary water flows through a steam generator, where it boils feedwater in the secondary plant cycle to create steam. This steam then drives a series of turbines that rotate, generating electricity in the process. This secondary steam is separated from primary loop coolant by the steam generator, and is therefore not radioactive. As a large portion of the U.S. commercial nuclear power plant fleet were designed as Westinghouse 4-loop PWRs, this design was selected to be applicable to the greatest number of existing nuclear plants.

The reactor modeled in this report has a thermal power rating of 3650 MWt, with a plant generating capacity of approximately 1225 MWe. A thermal extraction case of 30% (~1095 MWt) thermal extraction was considered in this report with respect to a baseline case with no thermal extraction. Sections 4 discusses this case in further detail.

3.1.2. Affected Equipment

This report is primarily focused on the impacts of large-volume thermal extraction on the plant secondary cycle. Equipment is assessed to determine which specific components will require additional maintenance or replacement for 30% thermal extraction. The equipment assessed in Section 4.2 of this report includes:

- High Pressure Turbines (HPTs)

- Low Pressure Turbines (LPTs)

- Condensers

- Pumps

- Moisture Separator Reheaters (MSRs)

- Feedwater Heaters (FWHs)

- Extraction Steam

- Feedwater Heater Drains

- MSR Drains

3.1.3. General Arrangement

A generic plant arrangement, including thermal extraction, is provided in Figure 3-1. The next section describes the method of steam extraction and thermal conversion.
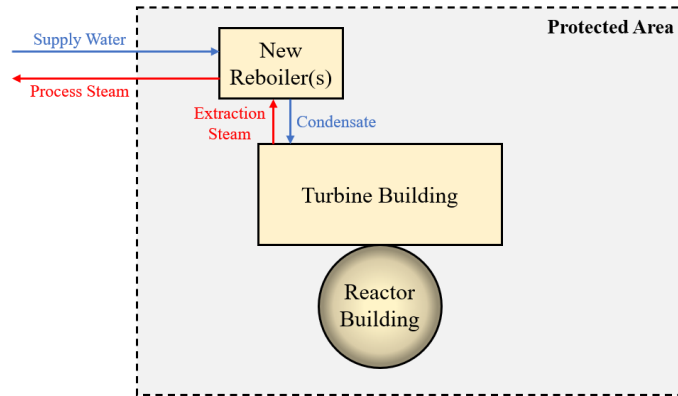
Figure 3-1. General Arrangement for Reference Plant Thermal Extraction

3.2. THERMAL EXTRACTION

Previous work has assessed the impacts of steam extraction up to 105 MWt (~3%) on the nuclear plant [1]. At this comparatively small volume of extraction, Cold Reheat (downstream of the high-pressure turbine) was deemed optimal from a nuclear plant efficiency standpoint. However, as higher steam volumes are extracted from the Cold Reheat, turbine shaft imbalance, blade loading, and thrust may cause the turbines to deviate from intended design. Therefore, Cold Reheat steam extraction is not recommended for higher power levels and not evaluated in this report. Additionally, higher quality and pressure of the main steam enables lower extraction volumes for the same thermal power, as well as smaller piping. As a result of these factors, the preferred location for 30% steam extraction is Main Steam (as opposed to Cold Reheat), upstream of the high-pressure turbine.

Main Steam extraction is shown in Figure 3-2.
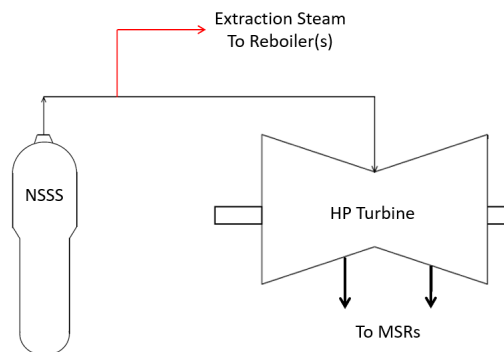
Figure 3-2. Main Steam Extraction

Following extraction, this steam would pass through a heat exchanger(s) in the Protected Area, where it would boil demineralized feed water which would be sent outside the plant boundary. The plant steam would condense in the heat exchanger before returning to the main condenser. Process steam would be piped to the desired use case. This could include hydrogen production (via high-temperature steam electrolysis), thermal storage, and district heating, among other applications.

The supply and return locations of nuclear steam/condensate is illustrated in Figure 3-3.
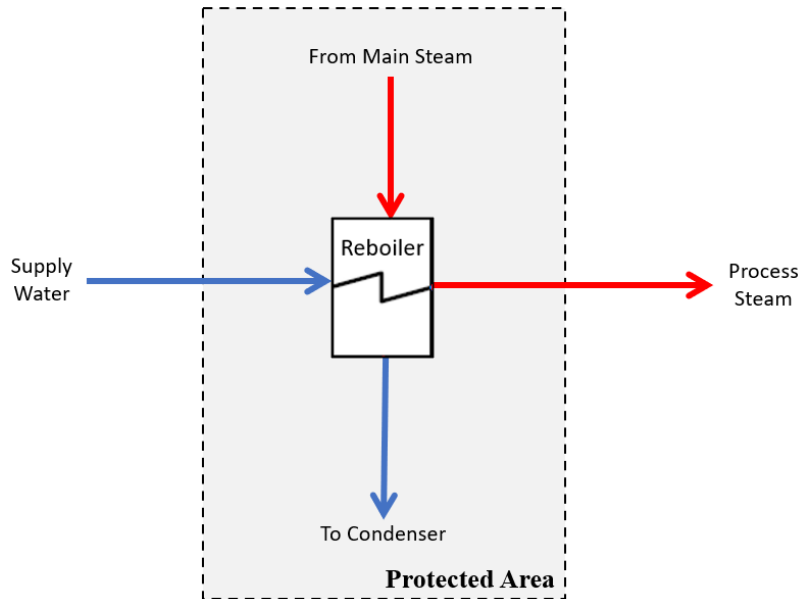
Figure 3-3. Supply and Return Locations

3.3. PEPSE HEAT BALANCE MODEL

3.3.1. Methodology

A generic PEPSE heat balance model of the reference plant is used as the starting point of this evaluation. This model is modified through the addition of splitters, mixers, and stream components to assess the impacts of 30% thermal extraction on the nuclear power cycle main steam system.

A heat exchanger component is used to model the steam reboiler thermal performance. The extracted steam is condensed and subcooled before it is returned to the power cycle. A pump component is used to model system pressure increase from a demineralized water supply tank to the reboiler. The amount of thermal energy extracted is calculated within PEPSE using operational variables. The amount of thermal energy extracted is controlled by changing the flow fraction out of the main steam splitter supplying the reboiler.

3.3.2. Assumptions

The PEPSE model is based on the following assumptions:

1. The temperature of the condensed and subcooled extraction steam is assumed to be 120°F before it is returned to condenser.

2. The discharge pressure for the water supply pump is assumed to be 650 psia.

3. The heat exchanger pressure drop is assumed to be 50 psid.

4. Pressure and temperature losses to the environment are included in the new associated stream components based on the assumed inputs in Table 3-1.

Table 3-1. PEPSE Model Input Assumptions

Description	Units	30% Extraction
Main Steam Extraction DP	psid	80
Main Steam Extraction Heat Loss	BTU/hr	210,000
Process Steam Extraction DP	psid	100
Process Steam Extraction Heat Loss	BTU/hr	2,230,000

4. 30% EXTRACTION RESULTS

4.1. THERMAL ANALYSIS

4.1.1. PEPSE

PEPSE computer program was utilized to determine the performance of the entire turbine cycle including prediction of the gross generator output. Modifying the generic PEPSE model, plant impact was assessed for 30% thermal extraction, as shown in Table 4-1. The PEPSE diagrams provided in Attachment A (pages A13, A14, and A15) show the results for the baseline (0% thermal extraction) and 30% thermal power extraction cases.

Table 4-1. General Impacts for 30% Thermal Extraction

Description	Units	0%	30%	Δ (30%)
Generator Electric Power	MWe	1,228.0	844.6	-31.2%
Thermal Power Extracted	MWt	0	1,095	-
% of Flow - MS	%	0	21.9	-
MS Flow from SGs	lbm/hr	16,037,390	15,436,290	-4%
HP Turbine Inlet Flow	lbm/hr	15,218,400	11,272,260	-26%
HP Turbine First Stage Pressure	psia	651.5	487.5	-25%
MSR Inlet Pressure	psia	190.3	140.2	-26%
LP Turbine Inlet Flow	lbm/hr	3,673,069	2,677,248	-27%
LP Turbine Inlet Pressure	psia	175.5	129.3	-26%
Condenser Duty	BTU/hr	8.21E+09	5.78E+09	-30%
Condensate Pump Flow	lbm/hr	11,334,490	11,723,820	3%
Heater Drain Pump Flow	lbm/hr	4,732,792	3,742,365	-21%
Feedwater Pump Flow	lbm/hr	16,067,280	15,466,190	-4%
Final Feedwater Temperature	°F	440.9	413.3	-27.6°F
Cascading Drain Flow to Condenser	lbm/hr	817,619	745,815	-9%
Cogen HX Inlet Mass Flow	lbm/hr	-	3,376,114	-
Cogen HX Inlet Pressure	psia	-	817.3	-
Cogen HX Inlet Temperature	°F	-	520.7	-
Cogen HX Inlet Enthalpy	BTU/lbm	-	1,197.2	-
Cogen HX Outlet Temperature	°F	-	120.0	-
Cogen HX Outlet Enthalpy	BTU/lbm	-	90.1	-

It is expected that this volume of thermal extraction will require four (4) trains. Each train should consist of a reboiler and drain cooler (to accommodate condensate cooling and preheating of reboiler feedwater). Using a Kettle style reboiler and shell and tube drain cooler, anticipated equipment dimensions are provided below in Figure 4-1.
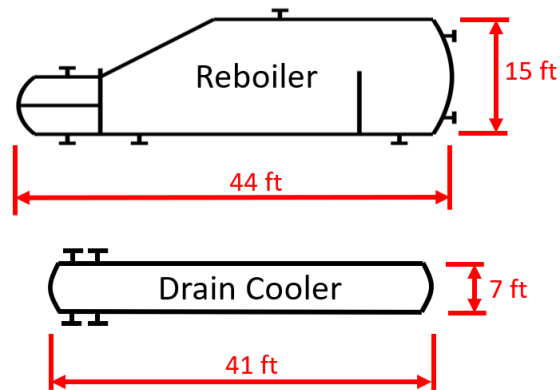
Figure 4-1. Heat Exchanger Dimensions (Side View)

Notes:
*   The reboiler is expected to be 12 ft wide.
**   The drain cooler is expected to be 5 ft wide.

4.1.2. Plant Impacts and Considerations

4.1.2.1.   Mechanical Transients

Plant operational transients must be assessed for 30% thermal extraction. Transient events will primarily occur during startup and shutdown of the extraction system. Under 1095 MWt extraction, approximately 3,380,000 lbm/hr of steam will be sent to the reboilers from Main Steam, corresponding to approximately 22% of Main Steam flow. This extraction will reduce total Main Steam flow by 600,000 lbm/hr, or 4%.

The below sections describe the capabilities of the reactor (in response to a load rejection event) and power cycle equipment in response to a transient event, as well as changes to normal operating conditions.

4.1.2.2.   Plant Hazards

Existing nuclear power plants are required to be protected from plant hazards such as high-energy line breaks (HELBs). Each station's licensing basis defines HELB criteria, which state the conditions required to define a high-energy system based on operating temperature and/or pressure limits. If a station is licensed to a temperature and pressure, both the minimum temperature and the minimum pressure criteria must be met for the system to be defined as a high-energy system. Conversely, if a station is licensed to a temperature or pressure, only one of the criteria need to be met for the system to be defined as a high-energy system. The temperature and pressure limits are defined as 200°F and 275 psig. As shown in the PEPSE heat balance diagram (Attachment A), the maximum operating conditions for 30% thermal extraction are 532°F and 897 psia. Both of these values exceed the criteria for a high-energy system, therefore steam extraction pipe design and installation would need to be performed under a station's HELB program.

A review of a plant's specific HELB program should be conducted to assess the impact of the new high-energy lines. Some stations analyze HELBs in the Turbine Building for impact on essential equipment. Any piping additions should be routed in such a way as to be separated from any equipment that may be important to safety or station operation. Any piping additions inside the Turbine Building routing to the steam reboilers are generally expected to be smaller than the main steam line they are tied into. Therefore, the impact of a HELB in the new piping is expected to be bounded by the mass and energy release rates for existing main steam piping. Any piping routed outdoors must also be designed in accordance with the station HELB program.

4.1.2.3. Water/Steam Hammer

During the detailed design of the thermal steam extraction system, the potential for water hammer or steam hammer must be addressed. These phenomena could occur if steam or water flow rapidly stops; this condition is typically addressed by selecting appropriate valve closing times.

4.1.2.4. Core Reactivity and Plant Response

4.1.2.4.1. Overview

The impact on core reactivity associated with extracting steam from the secondary cycle must be assessed for any plant-specific modification as described within this report. Reactivity impacts are derived not only from the steam extraction, but also from the reduced feedwater temperature resulting from the supply of reboiler condensate to the main condenser. Both steam extraction and feedwater temperature variation magnitude will impact core reactivity via the core negative moderator temperature coefficient (MTC). A negative core MTC can be understood broadly to create the effect "reactor power follows steam demand". The following description of core reactivity effects does not attempt to quantify the discrete contributions of the steam extraction and feedwater temperature variation. The goal is to explain reactivity changes resulting from thermal extraction operation and describe the expected nuclear plant control system response for extraction impacts relative to nominal plant response. The following descriptions assume that the nuclear plant is operating in Mode 1, above 15% reactor power.

Broadly speaking, thermal extraction will impact core reactivity much in the same manner as changing the main generator electrical output. Similar to raising generator output, ramp up of thermal extraction steam will add positive reactivity to the core through the negative MTC, resulting in a corresponding rise in reactor power. Shutdown of the thermal extraction supply will lower the reactor power through the same effects. The sequence described below illustrates how changes to the thermal demands on the nuclear plant secondary through operation of the extraction steam supply create this effect.

4.1.2.4.2. Core Reactivity Effects for Startup and Shutdown

In order to focus on the effects of the negative MTC, the following description purposely leaves out any discussion of plant control system response. That topic is discussed in the next section. The following describes how steam extraction and feedwater temperature changes result in reactivity changes in the core.

On extraction startup, steam extraction from the steam generators (SGs) increases. This higher flow lowers the pressure in the SGs. As SG pressure lowers, more liquid feedwater in the SGs flashes to steam. This results in more thermal energy being extracted from the reactor coolant flowing through the SG U-tubes, thereby lowering the primary coolant temperature. This "colder" primary coolant leaves the SGs and is supplied to the core. In possessing a negative MTC, colder water results in positive reactivity being added to the core.

In addition to steam extraction, startup of the thermal extraction system changes thermal characteristics of the nuclear plant through the lowering of feedwater temperature supplied to the SGs. As presented in Table 4-1, SG feedwater temperature lowers as extraction steam supply increases. Colder feedwater in the SG causes more thermal energy to be extracted from the primary coolant, once again delivering "colder" primary coolant to the core, adding positive reactivity, and causing a corresponding rise in reactor power. This occurs through the same negative MTC effect described in steam extraction above. Although the mechanism by which reactor coolant temperature lowers is different, the end result is the same; colder reactor coolant adds positive reactivity.

Startup, and subsequent raising of thermal extraction volume, adds positive reactivity to the core via the negative MTC. Both the added heat removal of steam extraction and the lower SG feedwater temperature occurring during thermal extraction system operations will lower the primary coolant returning to the core from the SGs. This positive reactivity causes more fissions in the core, thereby causing reactor power (i.e., thermal output) to rise. Increased heat production from more fissions raises the temperature of primary coolant leaving the core and being supplied to the SGs. With hotter primary coolant in the SG U-tubes, more feedwater boiling occurs and the SG pressure goes up. At this point, the effects described above are creating a new heat balance and begin to move towards achieving a new equilibrium.

After being initially lowered by added thermal output, the average primary coolant temperature rises with the increase in reactor power. The additional thermal extraction through startup and increased output of the thermal extraction system is now being provided through additional thermal power output of the core. As the average primary coolant temperature rises back to its previous level, reactor power will stabilize to meet the desired load.

Lowering the output and shutting down the thermal extraction system will result in the same effects described above but in reverse, with the negative MTC now causing an overall lowering of reactor thermal output. Reduced steam extraction and the associated increase in feedwater temperature will initially cause reactor coolant temperature to rise, and therefore reactor power to lower. When in operation, changes to thermal extraction output will drive the reactor thermal output to match the changes. As stated previously, the negative core MTC can be understood broadly to create the effect "reactor power follows steam demand".

4.1.2.4.3.   Control System Response

The previous description provides a straightforward discussion of the reactivity effects that will occur for changes in thermal extraction. The actual integrated plant response will be determined by the magnitude and rate of change for a particular transient. It is expected that any planned extraction output changes will be controlled within the same limits as planned main generator load changes in place for the station. Using this methodology, a planned extraction load change will cause a plant control system response that behaves nearly the same as a ramp down or ramp up of total plant power output. As described previously, there may be some minor differences created due to the lower feedwater temperatures. Changes should be evaluated in core and plant response analyses and accounted for through tuning of the plant controls.

The load change limits assumed in the reference plant are established based on typical Westinghouse 4-loop PWR controls designs. These limits would allow for the plant's Reactor Control System to act to preclude any compensatory actions beyond control rod motion. Typical Reactor Control System limits could enable the nuclear plant to accept a step load increase or decrease of 10% and a ramp increase or decrease of 5% per minute within the load range of 15% to 100% without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.

A condition for consideration is the sudden and complete loss of the thermal extraction steam when operating

at 100% capacity (i.e., 30% reactor power). In the event of this thermal load loss, the plant controls systems would respond to the resulting thermal imbalance. The Reactor Control System would activate control rod insertion at the maximum speed provided. This inward rod motion inserts negative reactivity to the core, reducing the number of fissions and thereby lowering reactor power. Additionally, the Steam Dump Controller would open valves that would dump steam directly to the main condenser. This would allow for continued heat removal from the core to prevent a rapid rise in primary coolant temperature and potential actuation of the pressurizer power-operated relief valves. The reference plant Reactor Control System is assumed to have the capacity to compensate for a 10% step change. Additionally, the Steam Dumps are assumed to compensate for up to 40% step change. Between the two responses, a complete loss of the 30% thermal extraction is well within plant control system response capacity.

4.2. EQUIPMENT ASSESSMENT

The effects of the 30% extraction on plant secondary equipment has been investigated. A detailed description of the effects on this equipment can be found in Attachments B through H.

4.2.1. Turbine Cycle

A representative turbine cycle was chosen to evaluate the impacts of thermal extraction on turbine performance and operations. A single HPT and three parallel LPTs were modeled. The representative cycle contains a MSR between the HPT and LPTs, where moisture is removed from the HPT exhaust and heated with two stages of regenerative heating. The turbines provide extraction to seven FWH stages.

The representative turbine cycle performance is modeled in a PEPSE model which contains cases benchmarked to the turbine vendor's thermal kit. Cases at Valves Wide Open (VWO), rated thermal power (100%), and 75% power are provided.

For the case with 30% turbine cycle thermal energy extracted, the PEPSE heat balance was modified as documented in Attachment A. The modification included removal of steam from the main steam system and return of the condensate to the main condenser after energy was extracted in the reboiler/s.

Table 4-2 shows the change in mass flows at various location along the turbines.

Table 4-2. Mass Flow Comparison

Location	Mass Flow Rate (lbm/hr)		Δ (30%)
	0%	30%	
Throttle Valve Inlet	15,218,400	11,272,260	-26%
HPT Bowl (Left)	7,609,201	5,636,129	-26%
Governing Stage Shell (Left)	7,609,201	5,636,129	-26%
FWH6 Extraction Stage (Left)	6,808,507	4,939,882	-27%
HPT Exhaust (Left)	6,808,507	4,939,882	-27%
HPT Bowl (Right)	7,609,201	5,636,129	-26%

Location	Mass Flow Rate (lbm/hr)		Δ (30%)
	0%	30%	
Governing Stage Shell (Right)	7,609,201	5,636,129	-26%
FWH7 + RH2 Extraction Stage (Right)	6,550,264	4,879,028	-26%
HPT Exhaust (Right)	6,550,264	4,879,028	-26%
LPT A Bowl	3,673,069	2,677,248	-27%
FWH4A Extraction Stage	3,470,241	2,479,494	-29%
FWH3A Extraction Stage	3,271,723	2,285,586	-30%
FWH2A Extraction Stage	3,075,061	2,108,017	-31%
MR (to FWH1A) Extraction Stage	3,015,812	2,069,513	-31%
FWH1A Extraction Stage	2,855,450	1,931,433	-32%
MR (to LPT A Exhaust) Extraction Stage	2,788,284	1,889,616	-32%
LPT A Exhaust	2,788,284	1,889,616	-32%
LPT B Bowl	3,673,069	2,677,248	-27%
FWH4B Extraction Stage	3,468,763	2,478,139	-29%
FWH3B Extraction Stage	3,273,638	2,287,097	-30%
FWH2B Extraction Stage	3,068,421	2,102,369	-31%
MR (to FWH1B) Extraction Stage	3,008,809	2,064,802	-31%
FWH1B Extraction Stage	2,847,364	1,924,897	-32%
MR (to LPT B Exhaust) Extraction Stage	2,780,228	1,882,541	-32%
LPT B Exhaust	2,780,228	1,882,541	-32%
LPT C Bowl	3,673,069	2,677,249	-27%
FWH4C Extraction Stage	3,473,448	2,482,813	-29%
FWH3CExtraction Stage	3,278,225	2,291,586	-30%
FWH2C Extraction Stage	3,070,612	2,103,231	-32%
MR (to FWH1C) Extraction Stage	3,011,389	2,064,763	-31%
FWH1C Extraction Stage	2,850,762	1,926,528	-32%
MR (to LPT C Exhaust) Extraction Stage	2,783,458	1,884,387	-32%
LPT C Exhaust	2,783,458	1,884,387	-32%

4.2.1.1. High-Pressure Turbine

As shown in Table 4-1, the main turbine is expected to experience a reduction in mass flow rate of at least 25% when operating in the 30% thermal extraction case. HPT flows are expected to reduce by a similar amount on either side of the HPT flow path. Therefore, additional stress due to turbine imbalance is not expected.

HPT performance modeled by PEPSE is visually represented on the Enthalpy-Entropy Chart in Figure 4-2.
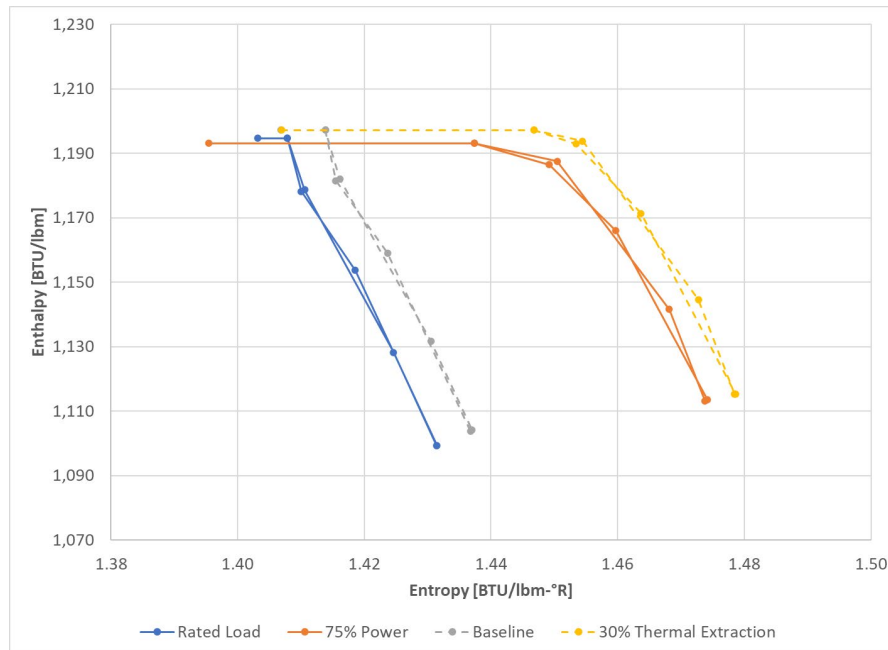
Figure 4-2. Enthalpy-Entropy Chart (HPT)

As shown in the entropy-enthalpy chart, the 30% thermal extraction case trends very closely with the 75% power case. Based on the review of PEPSE heat balance conditions, the turbine is expected to operate within design for the 30% thermal extraction case. However, final acceptability of operation under this condition must be confirmed with the turbine original equipment manufacturer (OEM) on a plant specific basis.

Complete HPT analysis is included as Attachment B.

4.2.1.2.   Low-Pressure Turbines

As shown in Table 4-1, the LPTs experience a mass flow rate reduction of at least 25% when operating in the 30% thermal extraction case.

The entropy-enthalpy chart for the LPTs is shown below in Figure 4-3.
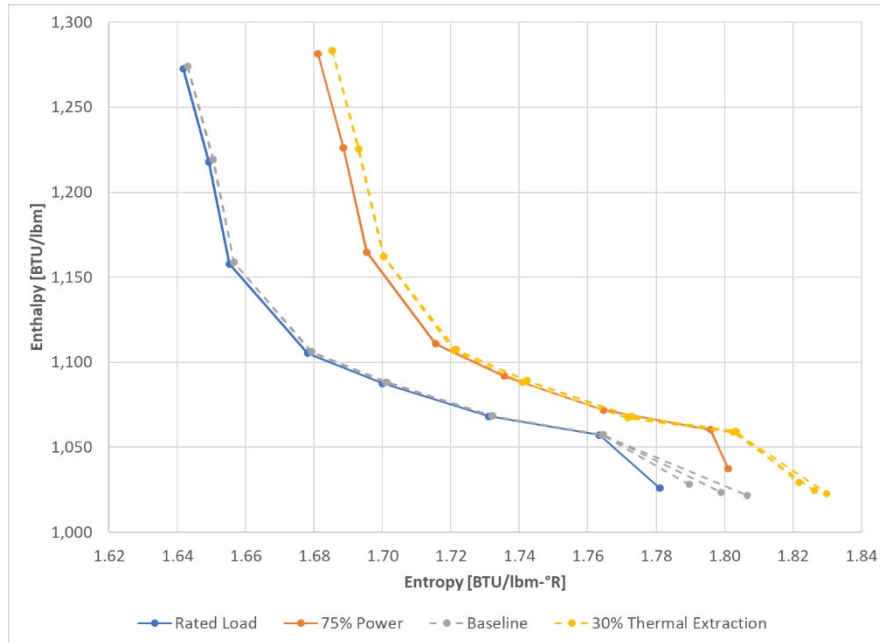
Figure 4-3. Enthalpy-Entropy Chart (LPTs)

As in the HPT Enthalpy-Entropy Chart, the 30% thermal extraction case trends very closely with the 75% power case. Based on the review of the PEPSE heat balance conditions, the turbine is expected to operate within design for up to 30% thermal extraction. Final acceptability of operation under this condition must be confirmed with the turbine OEM on a plant specific basis.

Complete analysis of the LPTs is included as Attachment B.

4.2.2. Condensers

The main condenser is the steam cycle heat sink. During normal operation it receives and condenses LP turbine exhaust steam and turbine bypass steam. The main condenser is also a collection point for other steam cycle miscellaneous flows, drains, and vents.

Although there are three independent zones for steam flow, the condenser has a single pass of Circulating Water (CW). CW enters at the low-pressure zone, passes through the intermediate-pressure zone, and exits at the high-pressure zone. The cold surface of the stainless steel tubes condense the steam into water, which is collected in the hotwell.

The operating conditions of the main condenser are evaluated for the 30% thermal extraction scenario with respect to baseline (0% thermal extraction) operation. Required air removal capacity is not specifically evaluated as, during operation, the major sources of noncondensable gases are not expected to change compared to baseline conditions.

Condenser operating conditions are tabulated below in Table 4-3.

Table 4-3. Condenser Operating Conditions

Description	Units	0%	30%	Δ (30%)
Condenser A Shell Pressure	psia	1.24	1.01	-18.9%
Condenser A Shell Flow	lbm/hr	3,120,435	2,198,666	-29.5%
Condenser A Duty	BTU/hr	2.92E+09	2.11E+09	-27.8%
Condenser B Shell Pressure	psia	1.38	1.07	-22.5%
Condenser B Shell Flow	lbm/hr	2850639	1,928,182	-32.4%
Condenser B Duty	BTU/hr	2.64E+09	1.83E+09	-30.7%
Condenser C Shell Pressure	psia	1.64	1.22	-25.9%
Condenser C Shell Flow	lbm/hr	2,854,037	1,929,813	-32.4%
Condenser C Duty	BTU/hr	2.65E+09	1.85E+09	-30.4%
Hotwell Temperature	°F	115.6	105.1	-10.5°F
Condensate Flow	lbm/hr	11,334,490	11,723,820	3.43%

The evaluation of condenser operating conditions shows that the condenser will continue to meet operation requirements for 30% thermal extraction conditions, and the evacuation capacity of the condensers is not affected by operating with 30% thermal extraction conditions. Condenser steam flow rates, backpressures, and heat loads decrease for the thermal extraction case; therefore, backpressure limits will not be challenged and flow-induced vibrations will be reduced. Overall condenser duty decreases for 30% thermal extraction since diverting large amount of main steam from the turbine cycle and condensing it elsewhere results in less heat removal in condenser given the same amount of circulating water.

A detailed analysis of the condenser can be found as Attachment C.

4.2.3. Pumps

The power conversion system is a closed cycle, with the condensate (CD), condensate booster (CB), and feedwater (FW) systems working to deliver water from the condenser hotwell to the four SGs. The Condensate Pumps (CDPs) draw water from the condenser and pump it through the Steam Jet Air Ejector (SJAE) Condensers and Gland Steam Condensers (GSCs) to the Condensate Booster Pumps (CBPs). The booster pumps provide the required head to pump condensate through the Low Pressure (LP) FWHs and to provide sufficient suction head at the two Turbine Driven Feed Pumps (TDFPs). The water collected from the heater

drains is stored in the Heater Drain Tank (HDT) and is forwarded into the CB system upstream of the 5th point heaters through the Heater Drain Pumps (HDPs). In the FW system, the water is pumped through one stage of High Pressure (HP) FWHs and then on to four SGs.

The power train pump systems evaluated in this report are the CDPs, CBPs, FWPs, and the HDPs, along with the associated HDT control valves. Each system is analyzed through the use of a generic Fathom hydraulic model of the CD, CB, HD forwarding, and FW systems. The condenser pressure, FW flow, HD flow, and water temperatures are taken from the PEPSE Heat Balance results. These conditions are shown in Attachment D.

4.2.3.1. Preferred Operating Region (POR)

Table 4-4 shows the preferred operating region (POR) for the four pumps evaluated. For the CDPs, CBPs, and TDFPs, the percent best efficiency point (BEP) remains within the associated POR, and changes from the base scenario to the 30% extraction case are minimal. The HDPs experience a significant change in operating point and will have to be evaluated on a plant-specific basis. However, it is not expected that any equipment changes will be required.

Table 4-4. Pump Preferred Operating Regions

Pump	Acceptance Criteria	0%	30%	Δ (30%)
Condensate Pumps (CDP)	70% - 120%	109.6	113.0	3.1%
Condensate Booster Pumps (CBP)	70% - 120%	114.3	117.8	3.1%
Turbine Drain Feed Pump (TDFP)	70% - 120%	99.1	95.2	-3.9%
Heater Drain Pumps (HDP)	80% - 115%	102.8	79.9	-22.3%

4.2.3.2. Pump Driver Duty

The power requirement for each pump to perform as hydraulically characterized in the Fathom model is reported as part of the pump performance results. The evaluation of these pump drivers under the baseline (0% thermal extraction) and 30% thermal extraction scenarios is tabulated in Table 4-5 below.

Table 4-5. Evaluation of Pump Driver Duty (hp)

Pump	Horsepower (hp)		Δ (30%)
	0%	30%	
CDP Gearbox	664	680	2.3%
CDP/CBP Motor	3157	3224	2.1%
TDFP Turbine	8590	8170	-4.9%
HDP Motor	1894	1877	-0.9%

The duty on the CDP gearbox and CDP/CBP motor increases slightly for the 30% extraction case. These will need to be evaluated against the rated horsepower of their associated drivers. The duty on the TDFP turbine and HDP motor decreases and is expected to meet the acceptance criteria for the 30% extraction case.

4.2.3.3. Net Positive Suction Head (NPSH) Ratio

The NPSH ratio (NPSHa/NPSHr) is a measure of the available suction head margin for a pump. Vertical pumps often operate without NPSH margin, and only require that the net positive suction head available (NPSHa) exceed the net positive suction head required (NPSHr). Though vertical pumps require an NPSH ratio of 1, a general acceptance criterion of 2.0 is used for conservatism.

Table 4-6 provides the NPSH ratio for the evaluated pumps.

Table 4-6. Evaluation of NPSH Ratio

Pump	HI / ANSI Guideline	0%	30%	Δ (30%)
CDP	≥ 2.0	1.86	1.76	-5.5%
CBP	≥ 2.5	2.86	2.39	-16.5%
TDFP	≥ 2.5	2.42	3.55	46.7%
HDP	≥ 2.0	16.27	16.13	-0.9%

The NPSH ratio for the TDFPs significantly improves, and while the NPSH ratio decreases for the HDPs, this change is small. The CDP NPSH ratio is below the HI/ANSI guideline for both cases, but it is not expected that thermal extraction will significantly increase the risk of cavitation since the change from the baseline scenario is relatively small (~5.5%). The NPSH ratio for CBPs decreases more significantly (over 16%) and it falls below the guideline for the 30% extraction case. Therefore, although no physical changes are expected to the CDPs, CBPs, and HDPs, they should be evaluated for acceptance on a plant-specific basis for the 30% extraction case.

4.2.3.4. Suction and Discharge Pressure

Suction and discharges pressures for each pump are compared in Table 4-7 below. This evaluation is used to see which pumps may be at risk of falling below alarm setpoints.

Table 4-7. Pump Suction and Discharge Pressures

Pump	Suction Pressure (psig)			Discharge Pressure (psig)		
	0%	30%	Δ (30%)	0%	30%	Δ (30%)
CDP	-5.1	-5.5	-3.9%	129.5	127.1	-1.6%
CBP	99.2	94.9	-3.8%	584.3	570.3	-2.3%
TDFP	425.0	412.3	-2.9%	1130.5	1122.1	-0.7%
HDP	184.8	136.5	-24.2%	696.1	763.6	9.5%

Overall, suction and discharge pressures decrease for the 30% thermal extraction case. Suction pressures will need to be evaluated on a plant-specific basis to ensure that they do not fall below low alarm setpoints. Alarm setpoints may need to be adjusted based on the conclusions of the plant-specific evaluation.

4.2.3.5.   Turbine Driven Feedwater Pump Speed

The FW flow through the pumps is regulated by the speed of the driving turbine, which receives steam from the main steam system. In the Fathom model, the turbine speed is calculated based on the required flow and developed head required of the TDFPs.

Table 4-8. Evaluation of FWP Turbine Speed

Description	Speed (rpm)		Δ (30%)
	0%	30%	
Max Calculated Turbine Speed	5,022	4,934	-1.8%

As shown in Table 4-8 above, the max calculated turbine speed decreases, therefore the margin improves for the 30% extraction case and is not expected to challenge the acceptance criteria for TDFP speed.

4.2.3.6.   Heater Drain Tank Level Control Valves

The heater drain tank level control valves are evaluated for controlling margin. Acceptable control margin corresponds to a valve position of less than 50% open, so that each operating valve maintains the ability to pass all of the drain flow.

Table 4-9. Heater Drain Level Control Valve Evaluation

Description	Acceptance Criteria	Valve Position (% Open)		Δ (30%)
		0%	30%	
HD Level Control Valve	≤ 50%	26.0	16.9	-35.1%

Based on these results in Table 4-9, the HD tank level control valves meet the acceptance criteria, improving margin for the 30% extraction case.

4.2.3.7.   Power Train Pump Assessment Summary

Based on the analysis above, the changes from baseline (0% extraction) operation to 30% extraction on power train pumps are minimal. It is not expected that there will be any equipment changes necessary. However, pumps should be evaluated on a plant-specific basis to ensure all acceptance criteria are met.

A detailed pump analysis is provided in Attachment D.

4.2.4. Moisture Separator Reheaters (MSRs)

The MSRs take wet exhaust steam from the HPT and pass it through a series of chevrons to remove moisture. The steam then goes through two stages of heat exchangers where it is heated before being sent to the LPTs.

MSR operating conditions for the baseline (0% thermal extraction) and 30% thermal extraction scenarios are compared in Table 4-10.

Table 4-10. MSR Operating Conditions

Description	Units	0%	30%	Δ (30%)
MSR Removal Effectiveness	-	0.95	0.95	0.00%
MSR Chevrons Inlet Flow	lbm/hr	3,151,396	2,266,680	-28.1%
MSR Chevrons Inlet Enthalpy	BTU/lbm	1,104	1,115	1.02%
MSR Chevrons Inlet Pressure	psia	190.3	140.2	-26.3%
MSR 1st Stage Inlet Enthalpy	BTU/lbm	1,193	1,189	-0.31%
MSR 1st Stage Inlet Pressure	psia	184.6	136.0	-26.3%
MSR 2nd Stage Inlet Enthalpy	BTU/lbm	1,227	1,222	-0.41%
MSR 2nd Stage Inlet Pressure	psia	181.8	134.0	-26.3%

The impacts to the MSRs are primarily a reduction in flow, with minimal change in enthalpies. The approximately 28% mass flow reduction is similar to 75% power with no thermal extraction. From these results, it is concluded that MSRs will not be affected by 30% thermal extraction operating conditions.

For a detailed analysis of the MSR, refer to Attachment E.

4.2.5. Feedwater Heaters

The Condensate (CD) and Feedwater (FW) systems deliver feedwater (condensed steam) to the steam generators. The CD system first directs flow through three parallel strings of low-pressure feedwater heaters (1st point external drain cooler and 1st through 4th point heaters). Flow then passes through two parallel strings of low-pressure feedwater heaters (5th point external drain cooler, 5th and 6th point heaters) to the TDFPs. FW flow then continues through two parallel high pressure feedwater heaters (7th point heaters) to the steam generators. The feedwater heaters receive extraction steam flow and moisture separator reheater drain flow from the turbine system. Relevant values from the FWH evaluation are provided below.

4.2.5.1. Nozzle and Tube Velocities

Table 4-11 provides the feedwater heater channel end nozzle velocities under baseline (0% thermal extraction) and 30% thermal extraction scenarios.

Table 4-11. Condensate/Feedwater Heater Nozzle Velocities

FW Heater	Velocity (ft/s)			Δ (30%)
	HEI Limit	0%	30%	
1st EDC	10	11.9	12.3	3.4%
1st Point	10	11.9	12.3	3.4%
2nd Point	10	11.9	12.3	3.4%
3rd Point	10	11.9	12.3	3.4%
4th Point	10	11.9	12.3	3.4%
5th EDC	10	10.0	10.3	3.4%
5th Point	10	9.6	9.2	-3.7%
6th Point	10	9.6	9.2	-3.7%
7th Point Inlet	10	10.2	9.8	-3.7%
7th Point Outlet	10	15.8	15.2	-3.7%

Tube side nozzle velocities exceed the Heat Exchange Institute (HEI) guidelines for several of the FWHs; however, changes from the baseline case are small. As a result, feedwater nozzle wear is not expected to be an issue.

Table 4-12 provides the FWH tube velocities based on the density at average tube temperature.

Table 4-12. FWH Tube Velocities

FW Heater	Velocity (ft/s)			Δ (30%)
	HEI Limit	0%	30%	
1st EDC	10	10.7	11.0	3.1%
1st Point	10	8.9	9.2	3.0%
2nd Point	10	9.1	9.3	2.7%
3rd Point	10	9.6	9.9	2.5%
4th Point	10	8.1	8.2	2.2%
5th EDC	10	7.0	7.1	2.0%
5th Point	10	9.1	8.6	-5.2%
6th Point	10	8.5	8.0	-5.4%
7th Point	10	8.8	8.3	-5.8%

Tube velocities remain below or marginally exceed the HEI guidelines for the 30% thermal extraction case. Because changes are small, it is not expected that this will impact FWH tube degradation.

Table 4-13 and Table 4-14 provide the FWH steam inlet and drain outlet nozzle velocities, respectively.

Table 4-13. Steam Inlet Nozzle Velocity

FW Heater	Velocity (ft/s)			Δ (30%)
	HEI Limit	0%	30%	
1st Point	215	137	181	32.6%
2nd Point	195	148	206	38.9%
3rd Point	179	179	249	39.1%
4th Point	167	156	214	37.5%
5th Point	156	101	115	37.2%
6th Point	150	103	139	19.8%
7th Point	146	80	123	5.39%

Table 4-14. Drain Outlet Nozzle Velocity

FW Heater	Velocity (ft/s)			Δ (30%)
	HEI Limit	0%	30%	
1st EDC	4.0	2.3	2.1	-9.13%
1st Point	4.0	1.8	1.5	-20.2%
2nd Point	4.0	2.9	2.7	-5.49%
3rd Point	4.0	2.4	2.3	-3.27%
4th Point	4.0	2.8	2.7	-3.63%
5th EDC	4.0	1.8	1.5	-14.1%
5th Point	4.0	2.5	2.1	-14.3%
6th Point	4.0	2.7	2.3	-13.7%
7th Point	4.0	2.2	1.9	-13.6%

Steam inlet nozzle velocities for the thermal extraction case increase for all FWHs and exceed the HEI guideline for the 2nd, 3rd and 4th point heaters. Shell wear rates will likely slightly increase and should be considered during regular future inspections. Based on the past experience with the power uprate projects which similarly increased flow velocities no FWH replacement is expected unless the existing FWH are in poor condition.

Drain outlet velocities decrease for the thermal extraction case, therefore HEI guidelines are not challenged, and wear rates may decrease.

4.2.5.2. Tube Side Pressure Drop

The tube side pressure drop principally affects two design issues, (i) the differential pressure across the pass partition plate (PPP), and (ii) the total pressure drop in the feedwater train.

To review the impact on PPP pressure loss, the change in mass flow rate squared is shown in Table 4-15.

Table 4-15. Pass Partition Plate Pressure Loss

FW Heater	Mass Flow Rate (lbm/hr)		Ratio of Flow Rates, R (30% / 0%)		PPP dP
	0%	30%	R	R²	
1st EDC	3,778,163	3,907,940	103%	107%	7.0%
1st Point	3,778,163	3,907,940	103%	107%	7.0%
2nd Point	3,778,163	3,907,940	103%	107%	7.0%
3rd Point	3,778,163	3,907,940	103%	107%	7.0%
4th Point	3,778,163	3,907,940	103%	107%	7.0%
5th EDC	5,667,245	5,861,910	103%	107%	7.0%
5th Point	8,033,640	7,733,095	96%	93%	-7.3%
6th Point	8,033,640	7,733,095	96%	93%	-7.3%
7th Point	8,033,640	7,733,095	96%	93%	-7.3%

The pressure loss across the PPP is expected to increase in FWHs 1 through 4 and both external drain coolers. However, the expected increase in tube side pressure drop for the thermal extraction case is not expected to appreciably impact reliable operation of the heaters.

4.2.5.3. Drain Inlet Nozzle Mass Flux

The mass flux and mass flux parameter of flashing condensate flows entering the shell side of the FWHs are provided in Table 4-16.

Drain inlet mass fluxes remain below HEI guidelines. However, the FWH 7 inlet mass flux parameter increases by nearly 50%; therefore, if the subject station does not show sufficient margin to allow for this increase, the drain inlets could see the additional flashing steam causing increased wear which should be considered during future inspections.

Table 4-16. Heater Drain Inlet Nozzle Mass Flux and Mass Flux Parameter

FW Heater	Mass Flux (lbm/s/ft^2)				Mass Flux Parameter (lbm/ft/s^2)			
	HEI Limit	0%	30%	Δ (30%)	HEI Limit	0%	30%	Δ (30%)
1st EDC	250	141	129	-8.9%	4,000	4,755	4,110	-13.6%
2nd Point	250	148	144	-2.4%	4,000	6,491	7,214	11.1%
3rd Point	250	179	174	-2.5%	4,000	4,141	4,741	14.5%
5th EDC	250	102	89	-12.9%	4,000	199	150	-25.4%
5th Point (cascading)	250	188	165	-12.2%	4,000	647	490	-24.3%
5th Point (MSR)	250	119	79	-33.2%	4,000	4409	2,414	-45.2%
6th Point	250	118	104	-11.7%	4,000	515	404	-21.7%
7th Point	250	112	107	-3.9%	4,000	2,177	3,231	48.4%

4.2.5.4. Operating Pressure and Temperature

Shell side operating pressure and temperature is provided in Table 4-17. Tube side operating temperature is provided in Table 4-18.

Table 4-17. Shell Side Operating Pressures and Temperatures

FW Heater	Pressure (psia)			Temperature (°F)		
	0%	30%	Δ (30%)	0%	30%	Δ (30%)
1st EDC	5.4	3.6	-33.4%	165.6	149.0	-16.6°F
1st Point	5.4	3.6	-33.0%	165.6	149.0	-16.6°F
2nd Point	15.9	10.8	-32.0%	215.9	196.8	-19.1°F
3rd Point	40.6	28.2	-30.6%	268.1	246.7	-21.4°F
4th Point	89.5	64.5	-28.0%	319.9	297.4	-22.4°F
5th EDC	186.1	137.1	-26.3%	375.8	351.4	-24.4°F
5th Point	186.1	137.1	-26.3%	375.8	351.4	-24.4°F
6th Point	287.1	212.7	-25.9%	413.3	387.0	-26.3°F
7th Point	408.7	303.0	-25.9%	446.7	418.3	-28.4°F

Table 4-18. Tube Side Operating Temperatures

FW Heater	Temperature (°F)		Δ (30%)
	0%	30%	
1st EDC	126.6	113.5	-13.1°F
1st Point	161.7	144.8	-16.9°F
2nd Point	212.8	192.6	-20.2°F
3rd Point	265.0	243.3	-21.7°F
4th Point	316.4	293.5	-22.9°F
5th EDC	332.2	306.8	-25.4°F
5th Point	370.2	345.9	-24.3°F
6th Point	409.7	383.7	-25.9°F
7th Point	441.5	413.8	-27.7°F

Operating temperatures and pressures decrease for all FWHs, therefore margins with design values will improve for the thermal extraction case.

4.2.5.5. Drain Cooler Tube Vibration

Tube vibration in the 1st through 7th point heater drain coolers is evaluated by comparing the drain cooler volumetric flow rates. Results are provided in Table 4-19 below.

Table 4-19. Drain Cooler Vibration

FW Heater	Drain Volumetric Flow Rate (gpm)		Δ (30%)
	0%	30%	
1st EDC	1,671	1,518	-9.1%
2nd Point	1,240	1,172	-5.5%
3rd Point	842	814	-3.3%
4th Point	439	423	-3.6%
5th EDC	3,767	3,235	-14.1%
6th Point	2,434	2,100	-13.7%
7th Point	1,578	1,363	-13.6%

The volumetric flow through all drain coolers is expected to decrease during operation, resulting in increased margin for tube vibration parameters.

4.2.5.6. Feedwater Heater Assessment Summary

Tube and tube side nozzle velocities exceed the HEI guidelines for several of the FWHs, but changes from the baseline case are small or decrease, therefore it is not expected that FWH tube degradation or nozzle wear will be an issue. Steam inlet nozzle velocities exceed HEI guidelines for the 2nd, 3rd, and 4th point heaters. This could affect wear patterns of the shells, which should be noted during future inspection. Tube side pressure drop for the thermal extraction case is not expected to appreciably impact reliable operation of the heaters. Drain inlet mass fluxes remain below HEI guidelines, but the mass flux parameters for various heaters exceed the guidelines for the thermal extraction case. For most FWHs, however, the mass flux parameter decreases or exhibits small increases. Operating temperatures and pressures decrease for all FWHs; therefore, design margins will improve for the thermal extraction case. Volumetric flow through all drain coolers is also expected to decrease during thermal extraction operation, resulting in increased margin for tube vibration parameters.

It is not anticipated that feedwater heaters replacement will be required for 30% thermal extraction. However, normal plant inspections would remain suitable to identify potential flow accelerated corrosion issues. This conclusion is supplemented by the past experience with power uprates which similarly increased flow velocities in these and many other locations no FWH replacements were required if the condition of the existing FWHs was satisfactory.

A detailed evaluation of the feedwater heaters is provided in Attachment F.

4.2.6. Extraction Steam

To maximize steam cycle efficiency, the Extraction Steam (ES) system diverts steam taken from the turbine to the feedwater heaters. There are three stages of extraction from the HPT and four stages of extraction from each LPT. The Extraction Steam is used to heat the feedwater in seven separate feedwater heater stages.

There are three trains for the 1st through 4th point LP feedwater heaters, two trains for the 5th and 6th point LP feedwater heaters, and two trains for the 7th point HP feedwater heater.

Heat balance data for the baseline (0% thermal extraction) and 30% thermal extraction scenarios is discussed below.

4.2.6.1. Pressure Drop

Table 4-20 shows the pressure drop in the ES lines.

Table 4-20. Extraction Steam Line Pressure Drop

Description	Upstream Pressure (psia)			Pressure Drop (psid)		
	0%	30%	Δ (30%)	0%	30%	Δ (30%)
HPT to 7th Stg FWH	451.0	337.0	-25.3%	6.50	5.24	-19.4%
HPT to 6th Stg FWH	296.5	219.7	-25.9%	8.46	8.82	4.2%
HPT to 5th Stg FWH	190.3	140.2	-26.3%	4.97	6.82	37.4%

Description	Upstream Pressure (psia)			Pressure Drop (psid)		
	0%	30%	Δ (30%)	0%	30%	Δ (30%)
LPT to 4th Stg FWH	92.39	66.6	-27.9%	4.33	5.80	33.9%
LPT to 3rd Stg FWH	41.9	29.11	-30.5%	3.24	4.41	35.8%
LPT to 2nd Stg FWH	16.43	11.18	-32.0%	0.78	0.98	25.9%
LPT to 1st Stg FWH	5.428	3.637	-33.0%	0.13	0.14	6.4%

The pressure drop in the lines from the HPT to 7th stage FWHs decreases, but all other extraction steam lines see an increase in pressure drop for the extraction case, with the most significant changes in lines to the 2nd, 3rd, 4th, and 5th stage FWHs.

4.2.6.2.　　Operating Conditions

ES line pressures and temperatures are compared below in Table 4-21.

Table 4-21. Extraction Steam Line Operating Conditions

Description	Line Pressure (psia)			Line Temperature (°F)		
	0%	30%	Δ (30%)	0%	30%	Δ (30%)
HPT to 1st Stg Rhtr	448.7	335.3	-25.3%	456.50	428.15	-28.4°F
HPT to 7th Stg FWH	408.7	303.0	-25.9%	456.50	428.15	-28.4°F
HPT to 6th Stg FWH	287.1	212.7	-25.9%	416.29	389.77	-26.5°F
HPT to 5th Stg FWH	186.1	137.1	-26.3%	377.64	353.15	-24.5°F
LPT to 4th Stg FWH	89.6	64.6	-27.9%	382.52	386.44	3.9°F
LPT to 3rd Stg FWH	40.6	28.2	-30.5%	270.06	248.61	-21.4°F
LPT to 2nd Stg FWH	15.9	10.8	-32.0%	217.68	198.51	-19.2°F
LPT to 1st Stg FWH	5.4	3.6	-33.0%	165.73	149.10	-16.6°F

Pressures and temperatures decrease for the thermal extraction case in all lines other than a small temperature increase in the 4th Stg FWH line. Based on these results, margins for design pressures and temperatures will largely improve for relevant valves and expansion joints.

4.2.6.3. Expansion Joint Liner Thickness

Required liner thicknesses are compared in Table 4-22.

Table 4-22. Expansion Joint Liner Thickness

Description	Required Liner Thickness (in)		Δ (30%)
	0%	30%	
LPT to 4th Stg FWH	0.137	0.160	17.2%
LPT to 3rd Stg FWH	0.138	0.163	17.9%
LPT to 2nd Stg FWH	0.156	0.184	17.8%
LPT to 1st Stg FWH	0.149	0.172	15.1%

Liner thickness requirements increase for the thermal extraction case. Existing expansion joints will need to be evaluated on a plant-specific basis and may need to be replaced to ensure they meet new liner thickness requirements.

4.2.6.4. Extraction Steam Assessment Summary

Analysis of the extraction steam system for the 30% thermal extraction scenario shows that overall, extraction steam line pressure drops increase due to higher flow velocities. The increased flow velocities should be included in the individual station Flow Accelerated Corrosion (FAC) program to ensure that any potential degradation is properly monitored and addressed.

Expansion joint liner thickness requirements also increase, and existing expansion joints will need to be evaluated on a plant-specific basis. Replacement may be needed to ensure expansion joint requirements are met. Pressures and temperatures mostly decrease during operation with thermal extraction, therefore operating condition design margins will largely improve for valves and expansion joints in the extraction steam system.

Refer to Attachment G for a detailed evaluation of the Extraction Steam system.

4.2.7. Heater Drain System

There are seven stages of feedwater heating for normal operations. Two parallel trains ('A' and 'B' trains), each consisting of FWH 5, 6 and 7 are available for normal operation. Drains cascade back to the heater drain tank starting at FWH 7. Flow for each train passes through the FWH 5 external drain coolers before entering the HDT. Emergency drains to the condenser are available for FWHs 5, 6, and 7.

Three parallel FWH drain trains ('A' train, 'B' train, and 'C' train), each consisting of a FWH 1, 2, 3, and 4, are available for normal operation. Drains cascade from FWH 4 to the flash tanks through FWHs 3 and 2. FWH 1 drain to the flash tanks as well. Each flash tank drains to the condenser via the FWH 1 external drain coolers. Emergency drains to the condenser are available for FWHs 4, 3, and 2, as well as the flash tanks.

Four MSR drain trains ('A' train, 'B' train, 'C' train, and 'D' train), each consisting of a moisture separator drain tank (MSDT), 1st stage reheater drain tank (RH1DT), and a 2nd stage reheater drain tank (RH2DT), are available for normal operation as well. The MSDT drains are directed to the HDT. The 1st and 2nd stage reheater drains are directed to FWHs 5 and 7, respectively. Emergency drain lines to the condenser are available for each of the drain lines.

4.2.7.1. Valve Flow Capacity

Valve volumetric flow is computed based on the mass flow rate and fluid temperature. Table 4-23 compares volumetric flow for the baseline (0% thermal extraction) and 30% thermal extraction scenarios.

Table 4-23. Drain Volumetric Flow Comparison

Description	Volumetric Flow Rate (gpm)		Δ (30%)
	0%	30%	
Flash Tank Normal	1,683	1,527	-9.3%
FWH 2 Normal	1,234	1,168	-5.4%
FWH 3 Normal	836	809	-3.2%
FWH 4 Normal	434	419	-3.6%
FWH 6 Normal	2,416	2,086	-13.7%
FWH 7 Normal	1,557	1,346	-13.5%
MSDT Normal	756	433	-42.8%
RHDT1 Normal	331	215	-34.9%
RHDT2 Normal	527	507	-3.9%
Flash Tank Emergency	1,683	1,527	-9.3%
FWH 2 Emergency	1,234	1,168	-5.4%
FWH 3 Emergency	836	809	-3.2%
FWH 4 Emergency	434	419	-3.6%
FWH 5 Emergency	3,890	3,335	-14.3%
FWH 6 Emergency	2,416	2,086	-13.7%
FWH 7 Emergency	1,557	1,346	-13.5%
MSDT Emergency	756	433	-42.8%
RHDT1 Emergency	331	215	-34.9%
RHDT2 Emergency	527	507	-3.9%

As shown above, all drains experience a decrease in flow.

4.2.7.2. Valve Pressure Drop

The pressure drop across the valve is the minimum of the allowable pressure drop due to choked flow and the available pressure drop from valve inlet to outlet based on flow conditions and frictional losses. Pressure loss is computed in Table 4-24.

Table 4-24. Drain Valve Pressure Loss

Description	Pressure Drop (psid)				Δ (30%)	
	0%		30%			
	Choked	Available	Choked	Available	Choked	Available
Flash Tank Normal	2.7	7.3	2.9	6.2	8.0%	-14.6%
FWH 2 Normal	2.3	3.2	0.5	0.5	-77.6%	-83.4%
FWH 3 Normal	9.1	14.6	4.7	7.6	-48.7%	-48.0%
FWH 4 Normal	32.1	44.5	23.5	32.2	-26.5%	-27.6%
FWH 6 Normal	85.0	95.9	63.3	70.8	-25.5%	-26.2%
FWH 7 Normal	90.9	108.1	65.3	76.9	-28.1%	-28.8%
MSDT Normal	19.6	5.9	15.1	6.5	-23.0%	11.0%
RHDT1 Normal	42.7	249.3	28.1	187.3	-34.0%	-24.9%
RHDT2 Normal	115.6	454.6	116.0	562.4	0.4%	23.7%
Flash Tank Emergency	4.1	9.2	4.1	7.8	-0.7%	-15.1%
FWH 2 Emergency	5.5	11.7	3.7	7.6	-32.5%	-35.0%
FWH 3 Emergency	15.0	37.1	10.6	25.4	-29.1%	-31.4%
FWH 4 Emergency	38.4	92.0	30.0	67.8	-21.9%	-26.3%
FWH 5 Emergency	23.0	196.4	18.5	148.1	-19.4%	-24.6%
FWH 6 Emergency	86.9	283.3	65.3	209.6	-24.9%	-26.0%
FWH 7 Emergency	97.5	405.9	72.0	300.9	-26.1%	-25.9%
MSDT Emergency	16.4	186.0	11.8	137.9	-28.2%	-25.9%
RHDT1 Emergency	47.6	444.7	32.9	333.2	-30.9%	-25.1%
RHDT2 Emergency	116.8	862.6	117.3	865.2	0.4%	0.3%

All drain control valves experience choked flow conditions except the moisture separator drain tank. With respect to valve capacity, a decrease in valve pressure loss is non-conservative; therefore, nearly all valves see a non-conservative reduction in allowable pressure loss. In most cases, the reduction in allowable pressure drop is significant, with FWH 2 normal drains seeing a greater than 80% reduction in pressure drop available.

4.2.7.3. Required Valve C_v

Required valve C_v values are shown in Table 4-25.

Table 4-25. Drain Valve Required C_v Capacity

Description	C_v		Δ (30%)
	0%	30%	
Flash Tank Normal	1019	892	-12.5%
FWH 2 Normal	796	1595	100.5%
FWH 3 Normal	271	367	35.8%
FWH 4 Normal	74	84	13.1%
FWH 6 Normal	245	248	0.9%
FWH 7 Normal	150	155	3.2%
MSDT Normal	292	160	-45.2%
RHDT1 Normal	46	37	-18.8%
RHDT2 Normal	43	41	-4.1%
Flash Tank Emergency	823	751	-8.7%
FWH 2 Emergency	520	600	15.5%
FWH 3 Emergency	211	243	15.4%
FWH 4 Emergency	68	74	9.7%
FWH 5 Emergency	759	731	-3.7%
FWH 6 Emergency	243	244	0.5%
FWH 7 Emergency	145	147	1.7%
MSDT Emergency	175	119	-31.9%
RHDT1 Emergency	43	34	-20.7%
RHDT2 Emergency	43	41	-4.1%

The required C_v capacity for all FWHs increases with 30% thermal extraction. Flash tank and the various MSR drain tanks all see reduced capacity requirements. FWHs 2 and 3 show significant increase in required flow capacity, with FWH 2 requiring approximately double the baseline capacity. It is expected that a station specific review of these FWHs would result in requiring valve replacement prior to 30% thermal extraction operation. Additional equipment changes are not expected, but station specific review is required.

4.2.7.4. Drain Tank Parameters

Table 4-26 provides the operating parameters for the drain tanks (MSDT, RH1DT, RH2DT, and Flash Tank).

Table 4-26. Drain Tank Conditions

Parameter	Units	0%	30%	Δ (30%)
MSDT Drain Flow	lbm/hr	331,167	192,757	-41.8%
RH1DT Drain Flow	lbm/hr	135,811	90,676	-33.2%
RH2DT Drain Flow	lbm/hr	200,488	192,645	-3.9%
Flash Tank Drain Flow	lbm/hr	821,877	749,629	-8.8%
MSDT Drain Pressure	psia	184.6	136.0	-26.3%
RH1DT Drain Pressure	psia	444.2	332.0	-25.3%
RH2DT Drain Pressure	psia	864.2	866.1	0.2%
Flash Tank Drain Pressure	psia	5.42	3.63	-33.0%
MSDT Drain Temperature	°F	375.1	350.8	-24.3°F
RH1DT Drain Temperature	°F	455.0	426.7	-28.3°F
RH2DT Drain Temperature	°F	527.2	527.4	0.3°F
Flash Tank Drain Temperature	°F	165.2	148.4	-16.8°F

Operating parameters for all heater drain system drain tanks either decrease or show minimal change and are expected to operate normally during thermal power extraction operation.

4.2.7.5. Heater Drain Assessment Summary

The required C_V capacity for all the flash tank and the various MSR drain tank drain control valves (DCVs) show reduced capacity requirements when operating with thermal power extraction. DCVs for all FWHs will require greater flow passing capability. FWHs 4, 6, and 7 exhibit required increases of less than 15%, which is typically within the operating margin of a well sized drain control valve. Therefore, no equipment changes would be expected, but a station specific review is required. FWHs 2 and 3, on the other hand, show significant increase in required flow capacity, with FWH 2 requiring approximately double the baseline capacity. Therefore, it is expected that a station specific review of these FWHs would result in requiring valve replacement prior to operation with thermal power extracted for FWHs 2 and 3. Operating parameters for all heater drain system drain tanks either decrease or show minimal change and are expected to operate normally during thermal power extraction operation.

A detailed evaluation of the Heater Drain system is provided in Attachment H.

5. CONCLUSIONS

This report develops a detailed PEPSE heat balance model for a generic nuclear power plant and evaluates the impact of 30% thermal extraction on the nuclear plant. Plant transients, hazards, and core reactivity impacts are assessed. New steam extraction lines would be included under station HELB programs. Reactor response to load rejection or other transient events would need to be assessed for acceptability through further core and plant response analysis. Following development of the PEPSE model, major equipment was analyzed to assess margin, maintenance, and replacement impacts under 30% thermal extraction.

High-pressure(HP)/low-pressure(LP) turbine and moisture separator reheater performance is very similar to the performance under a 75% power case; this operating profile is expected to be maintainable for long durations.

Condenser operating conditions are expected to continue to meet operation requirements while evacuation capacity will not be impacted.

There are minimal impacts on the power train pumps and replacement is not anticipated.

It is not expected that feedwater heater tube degradation or nozzle wear will be an issue, although heater shell wear patterns could be affected, resulting in increased degradation. Tube side pressure drop for the thermal extraction case is not expected to appreciably impact reliable operation of the heaters. Drain inlet mass fluxes remain bounded by industry guidance. However, mass flux parameters for specific heaters were shown to exceed guidelines and could result in increased wear rates. Operating temperatures and pressures decreased for all feedwater heaters, increasing design margin. Volumetric flow through all drain coolers is also expected to decrease, resulting in increased margin for tube vibration parameters.

Analysis of the extraction steam system shows that overall, extraction steam line pressure drops increase due to higher flow velocities. The increased flow velocities should be included in the individual station Flow Accelerated Corrosion (FAC) program to ensure that any potential degradation is properly monitored and addressed. Expansion joint liner thickness requirements also increased. Replacement of expansion joints may be needed to ensure requirements are met with thermal extraction conditions. As a result of pressures and temperatures mostly decreasing with thermal extraction, operating condition margins largely improved for valves and expansion joints in the extraction steam system.

Heater drain tanks are expected to operate normally. Feedwater heater (FWH) drain control valves (DCVs) will require greater flow passing capability. Therefore, station specific review is required. It is expected that station specific review will find replacement of the FWH 2 and 3 DCVs necessary due to significant increase in required valve C_V when operating with 30% thermal extraction.

The conclusions above establish that 30% thermal extraction can be performed safely without major plant equipment replacement. Minor upgrades and increased maintenance may be required for specific plant components (e.g., expansion joints and DCVs).

The results described herein are based on a generic reference plant and PEPSE model. Plant specific evaluation of core/plant response and equipment would be required for any station considering a modification of this type. The results of a site-specific evaluation may differ from this generic PEPSE model analysis and equipment assessment based on plant/equipment design, operation, and age.

6. REFERENCES

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7. ATTACHMENTS

Attachment A – PEPSE Modeling for 30% Extraction

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Reviewed: Nic Richards

A1   Purpose

The purpose of this attachment is to evaluate the impact of extracting steam from the nuclear power cycle main steam system to supply thermal energy to the plant boundary for off-site use. The steam is condensed in a reboiler unit and returned to the nuclear power cycle. The thermal energy used by the reboiler unit is used to boil water to steam which is then directly supplied to the plant boundary. The main purpose of this attachment is to evaluate the impact on plant systems for 30% extraction of thermal energy from the main power cycle.

A2   Methodology

A generic station PEPSE model is used as the starting point of this evaluation. The generic station is a representative 4 Loop Westinghouse PWR with a targeted generator output of ~1225 MWe.

The generic PEPSE model is modified by adding splitters, mixers, and stream components to allow extraction from main steam and return to the main condenser.

A heat exchanger component is used to model the steam reboiler thermal performance. The extracted steam is condensed and subcooled before it is returned to the main power cycle.

A pump component is used to model system pressure increase from a demineralized water supply tank supplying water to the reboiler, which boils this water to steam (which is then supplied to the plant boundary). The amount of thermal energy extracted is calculated within PEPSE using operational variables. The amount of thermal energy extracted is controlled by changing the flow fraction out of the main steam splitter supplying the reboiler.

A3   Assumptions

A3.1   The temperature of the condensed and subcooled extraction steam is assumed to be 120°F before it is returned to condenser.

A3.2   The discharge pressure for the cogen water supply pump is assumed to be 650 psia.

A3.3   The cogen heat exchanger and piping pressure drop is assumed to be 50 psid. Therefore, the heat exchanger discharge is saturated steam at 600 psia.

A3.4   Pressure and temperature losses to the environment are included in the new associated stream components based on the assumed inputs in the following table.

Description	Units	30%
Main Steam Extraction DP	psid	80
Main Steam Extraction Heat Loss	BTU/hr	210,000
Process Steam Extraction DP	psid	100
Process Steam Extraction Heat Loss	BTU/hr	2,230,000

A4   References

A4.1   PEPSE V84 Computer software, (S&L program # 03.7.551-84.0)

A5   Results of 30% thermal extraction

The base PEPSE model is modified, as discussed in Section A2, to allow the targeted thermal extraction level to be achieved. The PEPSE diagrams (located at the end of the Attachment A) show the results considering 1) No thermal power extraction (i.e., no off-site use), 2) 30% thermal power extraction. Tables A5.1-A5.7 compare important operating parameters within the nuclear power cycle to determine possible significant impact to station equipment.

Table A5.1: General Impacts

Description	Units	0%	30%	Δ (30%)
Generator Electric Power	MWe	1,228.0	844.6	-31.2%
Thermal Power Extracted	MWt	0	1,095	-
% of Flow - MS	%	0	21.9	-
MS Flow	lbm/hr	16,037,390	15,436,290	-4%
HP Turbine Inlet Flow	lbm/hr	15,218,400	11,272,260	-26%
HP Turbine First Stage Pressure	psia	651.5	487.5	-25%
MSR Inlet Pressure	psia	190.3	140.2	-26%
LP Turbine Inlet Flow	lbm/hr	3,673,069	2,677,248	-27%
LP Turbine Inlet Pressure	psia	175.5	129.3	-26%
Condenser Duty	BTU/hr	8.21E+09	5.78E+09	-30%
Condensate Pump Flow	lbm/hr	11,334,490	11,723,820	3%
Heater Drain Pump Flow	lbm/hr	4,732,792	3,742,365	-21%
Feedwater Pump Flow	lbm/hr	16,067,280	15,466,190	-4%
Final Feedwater Temperature	°F	440.9	413.3	-27.6°F
Cascading Drain Flow to Condenser	lbm/hr	817,619	745,815	-9%
Cogen HX Inlet Mass Flow	lbm/hr	-	3,376,114	-
Cogen HX Inlet Pressure	psia	-	817.3	-
Cogen HX Inlet Temperature	°F	-	520.7	-
Cogen HX Inlet Enthalpy	BTU/lbm	-	1,197.2	-
Cogen HX Outlet Temperature	°F	-	120.0	-
Cogen HX Outlet Enthalpy	BTU/lbm	-	90.1	-

Table A5.2: MSR Impacts

Description	Units	0%	30%	Δ (30%)
MSR A Removal Effectiveness	-	95.0%	95.0%	0.0%
MSR A Chevrons Inlet Flow	lbm/hr	3,151,396	2,266,680	-28.1%

Description	Units	0%	30%	Δ (30%)
MSR A Chevrons Inlet Enthalpy	BTU/lbm	1,104.0	1,115.3	1.0%
MSR A Chevrons Inlet Pressure	psia	190.3	140.2	-26.3%
MSR A 1st Stage Inlet Enthalpy	BTU/lbm	1,192.7	1,189.0	-0.3%
MSR A 1st Stage Inlet Pressure	psia	184.6	136.0	-26.3%
MSR A 2nd Stage Inlet Enthalpy	BTU/lbm	1,226.8	1,221.8	-0.4%
MSR A 2nd Stage Inlet Pressure	psia	181.8	134.0	-26.3%
MSR B Removal Effectiveness	-	95.0%	95.0%	0.0%
MSR B Chevrons Inlet Flow	lbm/hr	3,151,396	2,266,680	-28.1%
MSR B Chevrons Inlet Enthalpy	BTU/lbm	1,104.0	1,115.3	1.0%
MSR B Chevrons Inlet Pressure	psia	190.3	140.2	-26.3%
MSR B 1st Stage Inlet Enthalpy	BTU/lbm	1,192.7	1,189.0	-0.3%
MSR B 1st Stage Inlet Pressure	psia	184.6	136.0	-26.3%
MSR B 2nd Stage Inlet Enthalpy	BTU/lbm	1,226.8	1,221.8	-0.4%
MSR B 2nd Stage Inlet Pressure	psia	181.8	134.0	-26.3%
MSR C Removal Effectiveness	-	95.0%	95.0%	0.0%
MSR C Chevrons Inlet Flow	lbm/hr	3,151,396	2,266,680	-28.1%
MSR C Chevrons Inlet Enthalpy	BTU/lbm	1,104.0	1,115.3	1.0%
MSR C Chevrons Inlet Pressure	psia	190.3	140.2	-26.3%
MSR C 1st Stage Inlet Enthalpy	BTU/lbm	1,192.7	1,189.0	-0.3%
MSR C 1st Stage Inlet Pressure	psia	184.6	136.0	-26.3%
MSR C 2nd Stage Inlet Enthalpy	BTU/lbm	1,226.8	1,221.8	-0.4%
MSR C 2nd Stage Inlet Pressure	psia	181.8	134.0	-26.3%
MSR D Removal Effectiveness	-	95.0%	95.0%	0.0%
MSR D Chevrons Inlet Flow	lbm/hr	3,151,396	2,266,680	-28.1%
MSR D Chevrons Inlet Enthalpy	BTU/lbm	1,104.0	1,115.3	1.0%
MSR D Chevrons Inlet Pressure	psia	190.3	140.2	-26.3%
MSR D 1st Stage Inlet Enthalpy	BTU/lbm	1,192.7	1,189.0	-0.3%
MSR D 1st Stage Inlet Pressure	psia	184.6	136.0	-26.3%
MSR D 2nd Stage Inlet Enthalpy	BTU/lbm	1,226.8	1,221.8	-0.4%
MSR D 2nd Stage Inlet Pressure	psia	181.8	134.0	-26.3%

Table A5.2: MSR Drain Impacts

Description	Units	0%	30%	Δ (30%)
MSDT A Drain Flow	lbm/hr	331,167	192,757	-41.8%
MSDT A Drain Enthalpy	BTU/lbm	348.4	322.6	-7.4%
MSDT A Drain Pressure	psia	184.6	136.0	-26.3%
MSDT A Drain Temperature	°F	375.1	350.8	-24.3°F
RH1 A Drain Flow	lbm/hr	135,811	90,676	-33.2%

Description	Units	0%	30%	Δ (30%)
RH1 A Drain Enthalpy	BTU/lbm	451.2	420.3	-6.9%
RH1 A Drain Pressure	psia	444.2	332.0	-25.3%
RH1 A Drain Temperature	°F	455.0	426.7	-28.3°F
RH2 A Drain Flow	lbm/hr	200,587	192,740	-3.9%
RH2 A Drain Enthalpy	BTU/lbm	534.5	534.8	0.1%
RH2 A Drain Pressure	psia	865.1	866.9	0.2%
RH2 A Drain Temperature	°F	527.3	527.5	0.2°F
MSDT B Drain Flow	lbm/hr	331,167	192,757	-41.8%
MSDT B Drain Enthalpy	BTU/lbm	348.4	322.6	-7.4%
MSDT B Drain Pressure	psia	184.6	136.0	-26.3%
MSDT B Drain Temperature	°F	375.1	350.8	-24.3°F
RH1 B Drain Flow	lbm/hr	135,811	90,676	-33.2%
RH1 B Drain Enthalpy	BTU/lbm	451.2	420.3	-6.9%
RH1 B Drain Pressure	psia	444.2	332.0	-25.3%
RH1 B Drain Temperature	°F	455.0	426.7	-28.3°F
RH2 B Drain Flow	lbm/hr	200,731	192,982	-3.9%
RH2 B Drain Enthalpy	BTU/lbm	535.2	535.4	0.0%
RH2 B Drain Pressure	psia	869.3	870.8	0.2%
RH2 B Drain Temperature	°F	527.9	528.1	0.2°F
MSDT C Drain Flow	lbm/hr	331,167	192,757	-41.8%
MSDT C Drain Enthalpy	BTU/lbm	348.4	322.6	-7.4%
MSDT C Drain Pressure	psia	184.6	136.0	-26.3%
MSDT C Drain Temperature	°F	375.1	350.8	-24.3°F
RH1 C Drain Flow	lbm/hr	135,811	90,676	-33.2%
RH1 C Drain Enthalpy	BTU/lbm	451.2	420.3	-6.9%
RH1 C Drain Pressure	psia	444.2	332.0	-25.3%
RH1 C Drain Temperature	°F	455.0	426.7	-28.3°F
RH2 C Drain Flow	lbm/hr	200,371	192,469	-3.9%
RH2 C Drain Enthalpy	BTU/lbm	533.9	534.2	0.1%
RH2 C Drain Pressure	psia	861.3	863.5	0.2%
RH2 C Drain Temperature	°F	526.8	527.1	0.3°F
MSDT D Drain Flow	lbm/hr	331,167	192,757	-41.8%
MSDT D Drain Enthalpy	BTU/lbm	348.4	322.6	-7.4%
MSDT D Drain Pressure	psia	184.6	136.0	-26.3%
MSDT D Drain Temperature	°F	375.1	350.8	-24.3°F
RH1 D Drain Flow	lbm/hr	135,811	90,676	-33.2%
RH1 D Drain Enthalpy	BTU/lbm	451.2	420.3	-6.9%
RH1 D Drain Pressure	psia	444.2	332.0	-25.3%

Description	Units	0%	30%	Δ (30%)
RH1 D Drain Temperature	°F	455.0	426.7	-28.3°F
RH2 D Drain Flow	lbm/hr	200,264	192,389	-3.9%
RH2 D Drain Enthalpy	BTU/lbm	533.8	534.2	0.1%
RH2 D Drain Pressure	psia	861.0	863.2	0.2%
RH2 D Drain Temperature	°F	526.7	527.0	0.3°F

Table A5.3: Turbine Impacts

Description	Units	0%	30%	Δ (30%)
MSR to LPT A Flow	lbm/hr	3,673,069	2,677,248	-27.1%
MSR to LPT A Enthalpy	BTU/lbm	1,273.9	1,283.4	0.7%
LPT A Inlet Pressure	psia	175.5	129.3	-26.3%
LPT A Inlet Temperature	°F	504.2	513.4	9.2°F
MSR to LPT B Flow	lbm/hr	3,673,069	2,677,248	-27.1%
MSR to LPT B Enthalpy	BTU/lbm	1,273.9	1,283.4	0.7%
LPT B Inlet Pressure	psia	175.7	129.4	-26.3%
LPT B Inlet Temperature	°F	504.2	513.4	9.2°F
MSR to LPT C Flow	lbm/hr	3,673,069	2,677,249	-27.1%
MSR to LPT C Enthalpy	BTU/lbm	1,273.9	1,283.4	0.7%
LPT C Inlet Pressure	psia	175.7	129.4	-26.3%
LPT C Inlet Temperature	°F	504.2	513.4	9.2°F
HPT to 7th Stage FWHs Flow	lbm/hr	515,692	394,398	-23.5%
HPT to 7th Stage FWHs Enthalpy	BTU/lbm	1,144.6	1,159.7	1.3%
HPT to 7th Stage FWHs Pressure	psia	408.7	303.0	-25.9%
HPT to 6th Stage FWHs Flow	lbm/hr	800,695	696,247	-13.0%
HPT to 6th Stage FWHs Enthalpy	BTU/lbm	1,114.2	1,130.8	1.5%
HPT to 6th Stage FWHs Pressure	psia	287.1	212.7	-25.9%
HPT to 5th Stage FWHs Flow	lbm/hr	746,538	747,410	0.1%
HPT to 5th Stage FWHs Enthalpy	BTU/lbm	1,104.0	1,115.3	1.0%
HPT to 5th Stage FWHs Pressure	psia	186.1	137.1	-26.3%
LPT A to FWH 1A Flow	lbm/hr	219,611	176,583	-19.6%
LPT A to FWH 1A Enthalpy	BTU/lbm	729.4	797.3	9.3%
LPT A to FWH 1A Pressure	psia	5.43	3.64	-33.0%
LPT A to FWH 2A Flow	lbm/hr	196,662	177,570	-9.7%
LPT A to FWH 2A Enthalpy	BTU/lbm	969.8	1,011.7	4.3%
LPT A to FWH 2A Pressure	psia	15.91	10.82	-32.0%
LPT A to FWH 3A Flow	lbm/hr	198,518	193,908	-2.3%
LPT A to FWH 3A Enthalpy	BTU/lbm	1,158.7	1,162.2	0.3%
LPT A to FWH 3A Pressure	psia	40.6	28.2	-30.6%

Description	Units	0%	30%	Δ (30%)
LPT A to FWH 4A Flow	lbm/hr	202,828	197,755	-2.5%
LPT A to FWH 4A Enthalpy	BTU/lbm	1,219.2	1,225.5	0.5%
LPT A to FWH 4A Pressure	psia	89.5	64.5	-28.0%
LPT B to FWH 1B Flow	lbm/hr	221,057	177,472	-19.7%
LPT B to FWH 1B Enthalpy	BTU/lbm	730.6	800.9	9.6%
LPT B to FWH 1B Pressure	psia	5.41	3.62	-33.0%
LPT B to FWH 2B Flow	lbm/hr	205,217	184,728	-10.0%
LPT B to FWH 2B Enthalpy	BTU/lbm	972.9	1,020.5	4.9%
LPT B to FWH 2B Pressure	psia	15.87	10.79	-32.0%
LPT B to FWH 3B Flow	lbm/hr	195,125	191,042	-2.1%
LPT B to FWH 3B Enthalpy	BTU/lbm	1,158.7	1,162.2	0.3%
LPT B to FWH 3B Pressure	psia	40.6	28.2	-30.6%
LPT B to FWH 4B Flow	lbm/hr	204,306	199,109	-2.5%
LPT B to FWH 4B Enthalpy	BTU/lbm	1,219.1	1,225.4	0.5%
LPT B to FWH 4B Pressure	psia	89.5	64.5	-28.0%
LPT C to FWH 1C Flow	lbm/hr	219,850	176,703	-19.6%
LPT C to FWH 1C Enthalpy	BTU/lbm	729.7	797.4	9.3%
LPT C to FWH 1C Pressure	psia	5.42	3.63	-33.1%
LPT C to FWH 2C Flow	lbm/hr	207,613	188,354	-9.3%
LPT C to FWH 2C Enthalpy	BTU/lbm	976.3	1,016.5	4.1%
LPT C to FWH 2C Pressure	psia	15.88	10.79	-32.0%
LPT C to FWH 3C Flow	lbm/hr	195,223	191,228	-2.0%
LPT C to FWH 3C Enthalpy	BTU/lbm	1,158.8	1,162.4	0.3%
LPT C to FWH 3C Pressure	psia	40.6	28.2	-30.5%
LPT C to FWH 4C Flow	lbm/hr	199,621	194,435	-2.6%
LPT C to FWH 4C Enthalpy	BTU/lbm	1,219.2	1,225.6	0.5%
LPT C to FWH 4C Pressure	psia	89.6	64.6	-27.9%

Table A5.4: Feedwater Heater Impacts

Description	Units	0%	30%	Δ (30%)
DC 1A Discharge Temp	°F	126.3	113.3	-13.0°F
FWH 1A Discharge Temp	°F	161.1	144.2	-16.9°F
FWH 1A Extraction Pressure	psia	5.43	3.64	-33.0%
FWH 1A Drain Temp	°F	165.3	148.4	-16.8°F
FWH 2A Discharge Temp	°F	210.1	189.9	-20.2°F
FWH 2A Extraction Pressure	psia	15.91	10.82	-32.0%
FWH 2A Drain Temp	°F	169.8	151.9	-17.9°F
FWH 3A Discharge Temp	°F	263.1	241.3	-21.8°F

Description	Units	0%	30%	Δ (30%)
FWH 3A Extraction Pressure	psia	40.6	28.2	-30.6%
FWH 3A Drain Temp	°F	224.4	203.6	-20.8°F
FWH 4A Discharge Temp	°F	314.3	291.3	-23.0°F
FWH 4A Extraction Pressure	psia	89.5	64.5	-28.0%
FWH 4A Drain Temp	°F	274.0	251.6	-22.4°F
DC 5A Discharge Temp	°F	331.4	306.0	-25.5°F
FWH 5A Discharge Temp	°F	369.9	345.6	-24.3°F
FWH 5A Extraction Pressure	psia	186.1	137.1	-26.3%
FWH 5A Drain Temp	°F	375.8	351.4	-24.4°F
FWH 6A Discharge Temp	°F	409.5	383.5	-25.9°F
FWH 6A Extraction Pressure	psia	287.1	212.7	-25.9%
FWH 6A Drain Temp	°F	374.3	348.7	-25.6°F
FWH 7A Discharge Temp	°F	440.2	412.7	-27.5°F
FWH 7A Extraction Pressure	psia	408.7	303.0	-25.9%
FWH 7A Drain Temp	°F	420.2	392.4	-27.8°F
DC 1B Discharge Temp	°F	126.6	113.5	-13.1°F
FWH 1B Discharge Temp	°F	161.7	144.8	-16.9°F
FWH 1B Extraction Pressure	psia	5.41	3.62	-33.0%
FWH 1B Drain Temp	°F	165.1	148.3	-16.8°F
FWH 2B Discharge Temp	°F	212.8	192.6	-20.2°F
FWH 2B Extraction Pressure	psia	15.87	10.79	-32.0%
FWH 2B Drain Temp	°F	170.2	152.2	-17.9°F
FWH 3B Discharge Temp	°F	265.0	243.3	-21.7°F
FWH 3B Extraction Pressure	psia	40.6	28.2	-30.6%
FWH 3B Drain Temp	°F	225.3	204.5	-20.8°F
FWH 4B Discharge Temp	°F	316.4	293.5	-22.9°F
FWH 4B Extraction Pressure	psia	89.5	64.5	-28.0%
FWH 4B Drain Temp	°F	277.9	255.6	-22.3°F
DC 5B Discharge Temp	°F	332.2	306.8	-25.4°F
FWH 5B Discharge Temp	°F	370.2	345.9	-24.3°F
FWH 5B Extraction Pressure	psia	186.1	137.1	-26.3%
FWH 5B Drain Temp	°F	375.8	351.4	-24.4°F
FWH 6B Discharge Temp	°F	409.7	383.7	-25.9°F
FWH 6B Extraction Pressure	psia	287.1	212.7	-25.9%
FWH 6B Drain Temp	°F	375.5	349.8	-25.7°F
FWH 7B Discharge Temp	°F	441.5	413.8	-27.7°F
FWH 7B Extraction Pressure	psia	408.7	303.0	-25.9%
FWH 7B Drain Temp	°F	421.9	393.8	-28.0°F

Description	Units	0%	30%	Δ (30%)
DC 1C Discharge Temp	°F	125.9	113.0	-13.0°F
FWH 1C Discharge Temp	°F	160.8	143.9	-16.9°F
FWH 1C Extraction Pressure	psia	5.42	3.63	-33.1%
FWH 1C Drain Temp	°F	165.2	148.3	-16.9°F
FWH 2C Discharge Temp	°F	212.7	192.5	-20.3°F
FWH 2C Extraction Pressure	psia	15.88	10.79	-32.0%
FWH 2C Drain Temp	°F	169.9	151.9	-18.0°F
FWH 3C Discharge Temp	°F	264.6	242.9	-21.7°F
FWH 3C Extraction Pressure	psia	40.6	28.2	-30.5%
FWH 3C Drain Temp	°F	226.6	205.7	-20.9°F
FWH 4C Discharge Temp	°F	315.0	292.0	-22.9°F
FWH 4C Extraction Pressure	psia	89.6	64.6	-27.9%
FWH 4C Drain Temp	°F	274.6	252.3	-22.3°F
FWH 1A TTD	°F	4.7	4.9	0.2°F
FWH 1A DCA	°F	7.4	7.4	0.0°F
FWH 2A TTD	°F	5.9	7.0	1.1°F
FWH 2A DCA	°F	8.8	7.8	-1.0°F
FWH 3A TTD	°F	5.0	5.5	0.5°F
FWH 3A DCA	°F	14.3	13.6	-0.6°F
FWH 4A TTD	°F	5.6	6.2	0.6°F
FWH 4A DCA	°F	10.9	10.3	-0.5°F
FWH 5A TTD	°F	5.9	5.9	0.0°F
FWH 5A DCA	°F	6.2	4.2	-2.0°F
FWH 6A TTD	°F	3.9	3.5	-0.4°F
FWH 6A DCA	°F	4.4	3.1	-1.2°F
FWH 7A TTD	°F	6.5	5.6	-0.9°F
FWH 7A DCA	°F	7.5	5.8	-1.7°F
FWH 1B TTD	°F	3.9	4.2	0.3°F
FWH 1B DCA	°F	6.6	6.6	0.0°F
FWH 2B TTD	°F	3.1	4.2	1.1°F
FWH 2B DCA	°F	8.5	7.5	-1.0°F
FWH 3B TTD	°F	3.1	3.5	0.4°F
FWH 3B DCA	°F	12.5	11.9	-0.6°F
FWH 4B TTD	°F	3.5	4.0	0.5°F
FWH 4B DCA	°F	12.9	12.3	-0.6°F
FWH 5B TTD	°F	5.6	5.5	0.0°F
FWH 5B DCA	°F	6.1	4.2	-2.0°F
FWH 6B TTD	°F	3.7	3.3	-0.4°F

Description	Units	0%	30%	Δ (30%)
FWH 6B DCA	°F	5.3	3.9	-1.4°F
FWH 7B TTD	°F	5.2	4.4	-0.8°F
FWH 7B DCA	°F	9.2	7.2	-2.0°F
FWH 1C TTD	°F	4.9	5.1	0.2°F
FWH 1C DCA	°F	9.3	9.3	0.0°F
FWH 2C TTD	°F	3.2	4.4	1.2°F
FWH 2C DCA	°F	9.1	8.0	-1.1°F
FWH 3C TTD	°F	3.6	4.0	0.4°F
FWH 3C DCA	°F	13.9	13.3	-0.6°F
FWH 4C TTD	°F	5.0	5.5	0.5°F
FWH 4C DCA	°F	10.0	9.4	-0.5°F
Final FW Temperature	°F	440.9	413.2	-27.6°F
Final FW Flow	lbm/hr	16,067,280	15,466,190	-3.7%
Heater Drain Tank Pressure	psia	185.1	136.5	-26.3%
Heater Drain Tank Temperature	°F	336.6	307.7	-28.8°F
FWH 7A Drain Flow	lbm/hr	650,363	575,781	-11.5%
FWH 7B Drain Flow	lbm/hr	667,282	589,198	-11.7%
FWH 6A Drain Flow	lbm/hr	1,051,707	924,845	-12.1%
FWH 6B Drain Flow	lbm/hr	1,066,632	936,381	-12.2%
DC 5A Drain Flow	lbm/hr	1,698,661	1,481,925	-12.8%
DC 5B Drain Flow	lbm/hr	1,709,462	1,489,413	-12.9%
FWH 4A Drain Flow	lbm/hr	202,828	197,755	-2.5%
FWH 4B Drain Flow	lbm/hr	204,306	199,109	-2.5%
FWH 4C Drain Flow	lbm/hr	199,621	194,435	-2.6%
FWH 3A Drain Flow	lbm/hr	401,346	391,662	-2.4%
FWH 3B Drain Flow	lbm/hr	399,431	390,151	-2.3%
FWH 3C Drain Flow	lbm/hr	394,844	385,663	-2.3%
FWH 2A Drain Flow	lbm/hr	598,008	569,232	-4.8%
FWH 2B Drain Flow	lbm/hr	604,648	574,879	-4.9%
FWH 2C Drain Flow	lbm/hr	602,457	574,017	-4.7%
DC 1A Drain Flow	lbm/hr	817,619	745,815	-8.8%
DC 1B Drain Flow	lbm/hr	825,705	752,351	-8.9%
DC 1C Drain Flow	lbm/hr	822,307	750,720	-8.7%

Table A5.5: Condenser Impacts

Description	Units	0%	30%	Δ (30%)
Condenser A Shell Pressure	psia	1.242	1.007	-18.9%
Condenser B Shell Pressure	psia	1.381	1.071	-22.5%

Description	Units	0%	30%	Δ (30%)
Condenser C Shell Pressure	psia	1.642	1.218	-25.9%
CW Inlet Temperature	°F	83.3	83.3	0.0°F
CW Outlet Temperature	°F	105.6	99.0	-6.6°F

Table A5.6: Pump Impacts

Description	Units	0%	30%	Δ (30%)
Condensate Pumps dP	psid	139.9	140.3	0.3%
Condensate Booster Pumps dP	psid	398.5	398.5	0.0%
Condensate Flow	lbm/hr	11,334,490	11,723,820	3.4%
FWP A Flow	lbm/hr	8,033,640	7,733,095	-3.7%
FWP A dP	psid	659.4	665.2	0.9%
FWPT A Steam Flow	lbm/hr	130,855	131,974	0.9%
FWPT A Inlet Pressure	psia	173.9	128.1	-26.3%
FWPT A Inlet Enthalpy	BTU/lbm	1,273.9	1,283.4	0.7%
FWP B Flow	lbm/hr	8,033,640	7,733,095	-3.7%
FWP B dP	psid	659.4	665.2	0.9%
FWPT B Steam Flow	lbm/hr	130,855	131,974	0.9%
FWPT B Inlet Pressure	psia	173.9	128.1	-26.3%
FWPT B Inlet Enthalpy	BTU/lbm	1,273.9	1,283.4	0.7%

MSR Drain Parameters
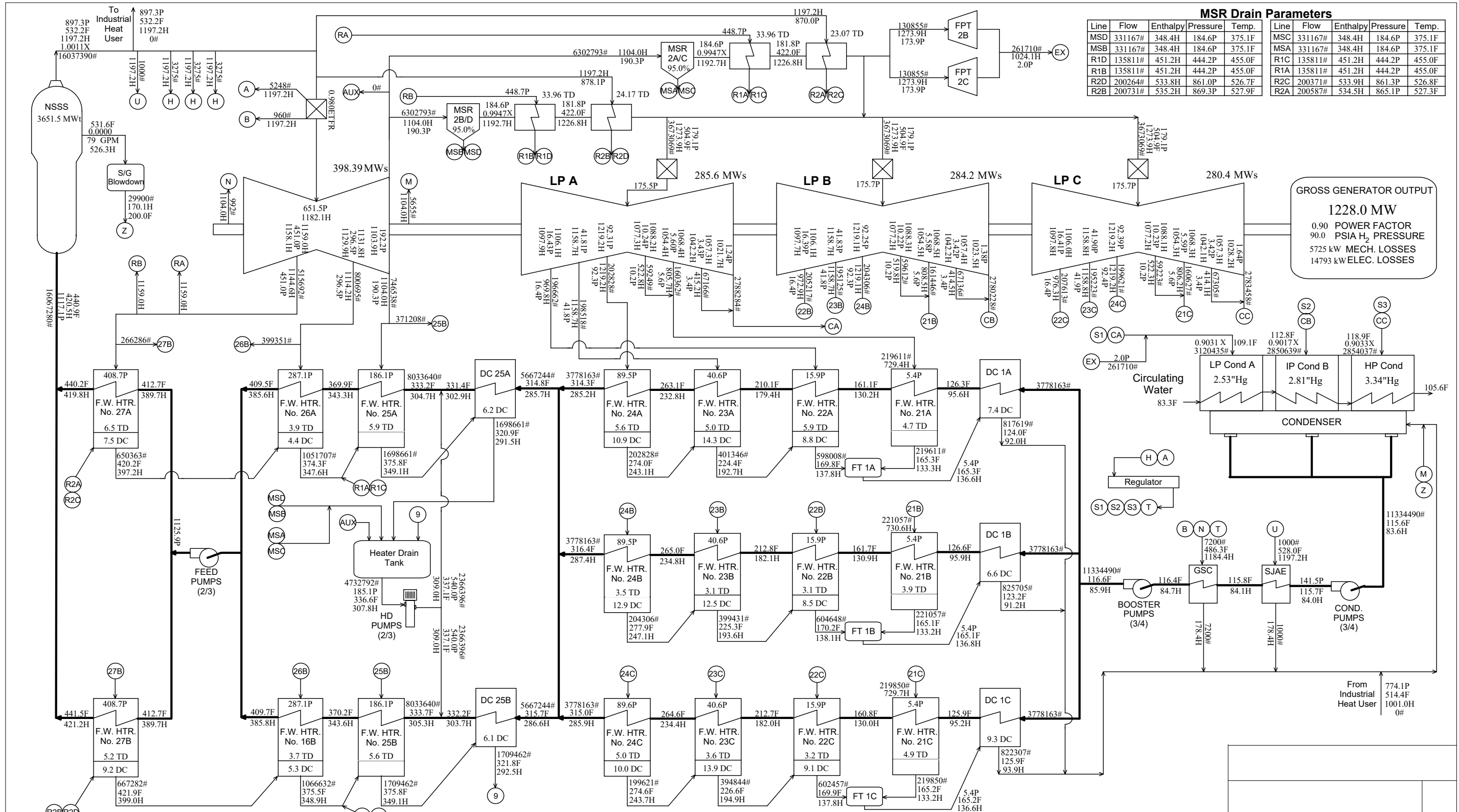
Line	Flow	Enthalpy	Pressure	Temp.	Line	Flow	Enthalpy	Pressure	Temp.
MSD	331167#	348.4H	184.6P	375.1F	MSC	331167#	348.4H	184.6P	375.1F
MSB	331167#	348.4H	184.6P	375.1F	MSA	331167#	348.4H	184.6P	375.1F
R1D	135811#	451.2H	444.2P	455.0F	R1C	135811#	451.2H	444.2P	455.0F
R1B	135811#	451.2H	444.2P	455.0F	R1A	135811#	451.2H	444.2P	455.0F
R2D	200264#	533.8H	861.0P	526.7F	R2C	200371#	533.9H	861.3P	526.8F
R2B	200731#	535.2H	869.3P	527.9F	R2A	200587#	534.5H	865.1P	527.3F

GROSS GENERATOR OUTPUT

1228.0 MW

0.90 POWER FACTOR
90.0 PSIA H₂ PRESSURE
5725 kW MECH. LOSSES
14793 kW ELEC. LOSSES

Notes:
1. Flows are schematic only and may represent two or more parallel paths.
2. FW heater vent flows are not modeled.
3. 1st and 2nd stage reheater scavenging steam is not modeled.
4. ETFR is estimated based on the thermal kit, and not benchmarked.
5. Generator p.f. is used to compute var losses. It should not be used for electrical system evaluations.
6. MSR reheat and heating steam P, T, & H shown for the 'B,' 'C' vessels as representative.

Gross Power:	1228.0 MW
NSSS Power:	3651.5 MWt
Gross HR:	10146B/kWh

Baseline (0% Thermal Extraction)

P - Pressure, psia
F - Temperature, F
H - Enthalpy, Btu/lbm
- Flow Rate, lbm/hr
× - Quality

MW - Megawatts
MWs - Megawatts Shaft Power
MWt - Megawatts Thermal

Prepared by:	Date:
Gabriel Neimark	06/01/23
Reviewed by:	Date:
Nic Richards	06/01/23

MSR Drain Parameters

Line	Flow	Enthalpy	Pressure	Temp.	Line	Flow	Enthalpy	Pressure	Temp.
MSD	192757#	322.6H	136.0P	350.8F	MSC	192757#	322.6H	136.0P	350.8F
MSB	192757#	322.6H	136.0P	350.8F	MSA	192757#	322.6H	136.0P	350.8F
R1D	90676#	420.3H	332.0P	426.7F	R1C	90676#	420.3H	332.0P	426.7F
R1B	90676#	420.3H	332.0P	426.7F	R1A	90676#	420.3H	332.0P	426.7F
R2D	192389#	534.2H	863.2P	527.0F	R2C	192469#	534.2H	863.5P	527.1F
R2B	192982#	535.4H	870.8P	528.1F	R2A	192740#	534.8H	866.9P	527.5F

GROSS GENERATOR OUTPUT

844.6 MW

0.90 POWER FACTOR
90.0 PSIA H$_2$ PRESSURE
5725 kW MECH. LOSSES
14110 kW ELEC. LOSSES

NSSS
3651.5 MWt

LP A   204.2 MWs
LP B   203.0 MWs
LP C   200.8 MWs

256.47 MWs

30% Thermal Extraction

Gross Power:	844.6 MW
NSSS Power:	3651.5 MWt
Gross HR:	14751 B/kWh

P - Pressure, psia
F - Temperature, F
H - Enthalpy, Btu/lbm
- Flow Rate, lbm/hr
× - Quality

MW - Megawatts
MWs - Megawatts Shaft Power
MWt - Megawatts Thermal

Notes:
1. Flows are schematic only and may represent two or more parallel paths.
2. FW heater vent flows are not modeled.
3. 1st and 2nd stage reheater scavenging steam is not modeled.
4. ETFR is estimated based on the thermal kit, and not benchmarked.
5. Generator p.f. is used to compute var losses. It should not be used for electrical system evaluations.
6. MSR reheat and heating steam P, T, & H shown for the 'B,' 'C' vessels as representative.

Prepared by: Gabriel Neimark	Date: 06/01/23
Reviewed by: Nic Richards	Date: 06/01/23
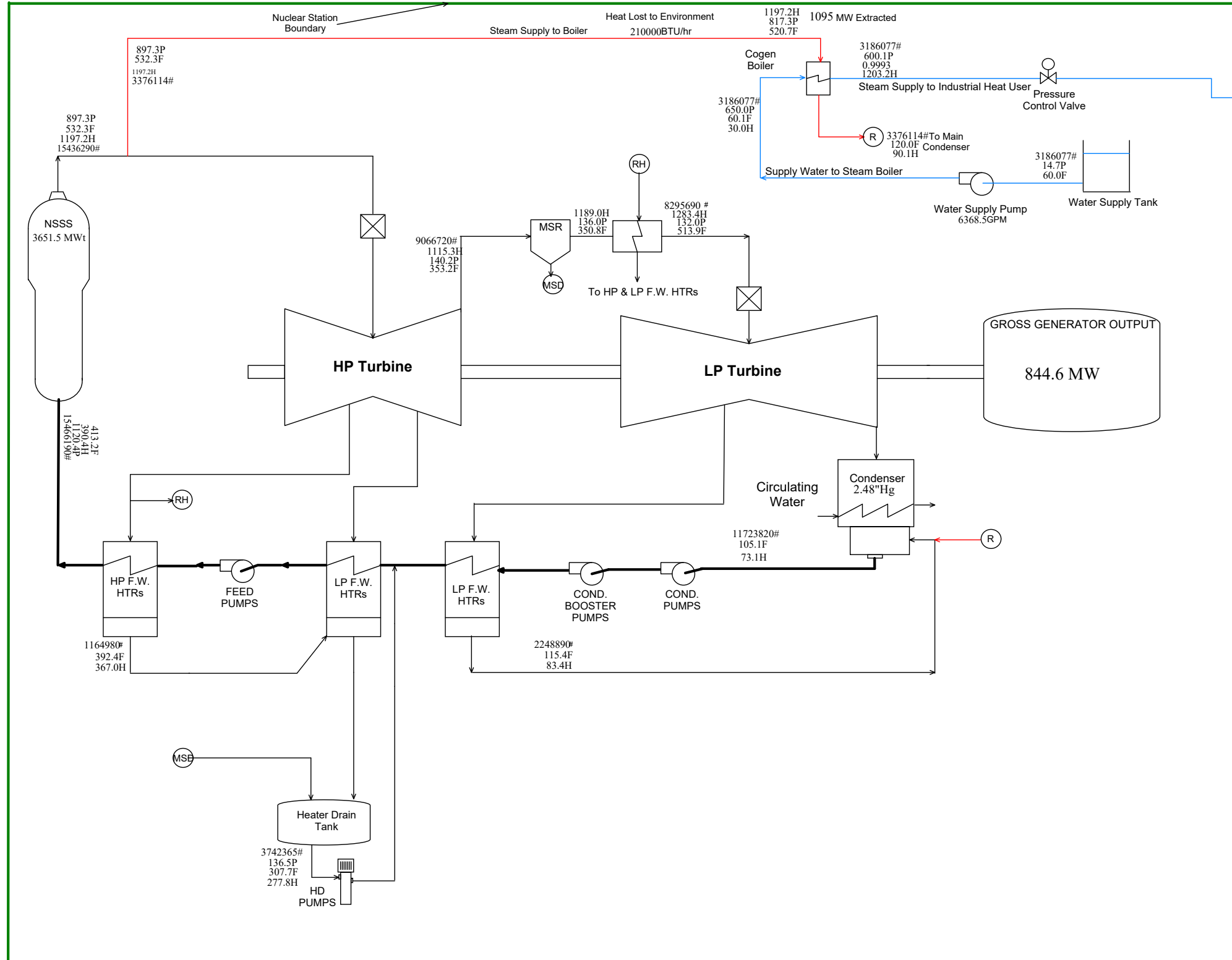
Turbine Cycle Heat Balance

30% Thermal Extraction

P - Pressure, psia	MW - Megawatts
F - Temperature, F	MWs - Megawatts Shaft Power
H - Enthalpy, Btu/lbm	MWt - Megawatts Thermal
# - Flow Rate, lbm/hr	
× - Quality	

Prepared by:	Date:
Gabriel Neimark	06/01/23
Reviewed by:	Date:
Nic Richards	06/01/23

Attachment B – HP and LP Turbine Assessment

Prepared: Nic Richards

Reviewed: Pawel Kut

B1.0   PURPOSE

The purpose of this appendix is to assess the turbine performance and expected changes to operating conditions due to operation with 30% turbine cycle thermal energy extracted from the main steam.

B2.0   SYSTEM & COMPONENT DESCRIPTION

A representative turbine cycle is chosen to evaluate the impact of energy extraction. A PWR unit with a single High Pressure Turbine (HPT) and three parallel Low Pressure Turbines (LPTs) is used. The representative cycle contains a Moisture Separator Reheater (MSR) between the HPT and LPTS, where moisture is removed from the HPT exhaust and heated with two stages of regenerative heating. The turbines provide extraction to seven feedwater heater stages.

The representative turbine cycle performance is modeled in a PEPSE™ model which contains cases benchmarked to the turbine vendor's thermal kit. Cases at Valves Wide Open (VWO), rated thermal power (100%), and 75% power are provided.

For the case with 30% turbine cycle thermal energy extracted, the PEPSE heat balance was modified as documented in Attachment A. The modification included removal of steam from the main steam system and return of the condensate to the main condenser after the energy was extracted.

B3.0   METHODOLOGY

B3.1   Enthalpy-Entropy Chart

Turbine performance modeled by PEPSE is visually represented on an Enthalpy-Entropy Chart. Turbine interstage pressures and enthalpies are taken from the PEPSE model for the Rated Load and 75% Load cases (see Input B5.1) to determine design turbine performance. The entropy of each condition is computed using Excel add-on STMFUNC, and plotted against the corresponding enthalpy. The same properties are extracted from the PEPSE model for the baseline scenario (0% thermal extraction) and 30% turbine cycle thermal energy extracted and plotted for comparison to the design turbine performance.

B3.2   Flow Comparison

The interstage mass flow rates from the baseline scenario and 30% turbine cycle thermal energy extracted case are compared. Any increases in flows are noted. Also, as the HPT is not symmetrical (FWH7 and 2nd Stage Reheat (RH2) extractions are taken from the right side and FWH6 extraction from the left), flow rates are reviewed for any potential imbalance between the two sides created when operating with 30% turbine cycle thermal energy extracted.

B4.0   ASSUMPTIONS

None

B5.0 **DESIGN INPUTS**

B5.1 Turbine Design Conditions at Rated and 75% Load

Turbine flows, pressures, and enthalpies are taken from the PEPSE model for the rated and 75% Load design case and presented in Table B5-1 below.

Table B5-1 – Turbine Design Values (from PEPSE™)

Location	Rated Load			75% Load		
	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]
Throttle Valve Inlet	15,606,360	882.0	1,195	10,980,900	948.9	1,193
HPT Bowl (Left)	7,803,179	834.6	1,195	5,490,452	583.8	1,193
Governing Stage Shell (Left)	7,803,179	666.4	1,179	5,490,452	473.0	1,188
FWH6 Extraction Stage (Left)	6,976,506	302.7	1,128	5,001,862	222.3	1,142
HPT Exhaust (Left)	6,976,506	192.1	1,099	5,001,862	144.9	1,113
HPT Bowl (Right)	7,803,179	834.6	1,195	5,490,452	583.8	1,193
Governing Stage Shell (Right)	7,803,179	666.4	1,178	5,490,452	473.3	1,186
FWH7 + RH2 Extraction Stage (Right)	6,517,590	447.4	1,154	4,791,225	329.6	1,166
HPT Exhaust (Right)	6,517,590	192.1	1,099	4,791,225	144.9	1,113
LPT A Bowl	3,675,072	175.3	1,273	2,743,459	132.2	1,282
FWH4A Extraction Stage	3,471,365	92.2	1,218	2,601,926	69.8	1,226
FWH3A Extraction Stage	3,277,938	41.9	1,158	2,467,812	31.4	1,165
FWH2A Extraction Stage	3,075,305	16.4	1,105	2,328,238	12.4	1,111
MR (to FWH1A) Extraction Stage	3,015,678	10.2	1,088	2,286,391	7.7	1,092
FWH1A Extraction Stage	2,869,644	5.62	1,068	2,206,928	4.31	1,072
MR (to LPT A Exhaust) Extraction Stage	2,801,781	3.44	1,057	2,158,431	2.64	1,060
LPT A Exhaust	2,801,781	1.72	1,026	2,158,431	1.72	1,038
LPT B Bowl	3,675,072	175.5	1,273	2,743,459	132.4	1,282
FWH4B Extraction Stage	3,471,369	92.2	1,218	2,601,930	69.8	1,226

	Rated Load			75% Load		
Location	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]
FWH3B Extraction Stage	3,277,928	41.9	1,158	2,467,806	31.4	1,165
FWH2B Extraction Stage	3,075,253	16.4	1,105	2,328,200	12.4	1,111
MR (to FWH1B) Extraction Stage	3,015,598	10.2	1,088	2,286,331	7.7	1,092
FWH1B Extraction Stage	2,869,548	5.62	1,068	2,206,856	4.31	1,072
MR (to LPT B Exhaust) Extraction Stage	2,801,669	3.44	1,057	2,158,346	2.64	1,060
LPT B Exhaust	2,801,669	1.72	1,026	2,158,346	1.72	1,037
LPT C Bowl	3,675,072	175.5	1,273	2,743,459	132.4	1,282
FWH4C Extraction Stage	3,471,370	92.2	1,218	2,601,930	69.8	1,226
FWH3CExtraction Stage	3,277,928	41.9	1,158	2,467,806	31.4	1,165
FWH2C Extraction Stage	3,075,259	16.4	1,105	2,328,195	12.4	1,111
MR (to FWH1C) Extraction Stage	3,015,604	10.2	1,088	2,286,326	7.7	1,092
FWH1C Extraction Stage	2,869,642	5.62	1,068	2,206,766	4.31	1,072
MR (to LPT C Exhaust) Extraction Stage	2,801,762	3.44	1,057	2,158,258	2.64	1,060
LPT C Exhaust	2,801,762	1.72	1,026	2,158,258	1.72	1,037

B5.2   Turbine Baseline and 30% Thermal Extraction Conditions

Turbine flows, pressures, and enthalpies are taken from the PEPSE model for the baseline (0% thermal extraction) and 30% Thermal Extraction cases and presented in Table B5-2 below.

Table B5-2 – Turbine Performance Values (from PEPSE™)

	Baseline (0% Thermal Extraction)			30% Thermal Extraction		
Location	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]
Throttle Valve Inlet	15,218,400	870.3	1,197	11,272,260	870.3	1,197
HPT Bowl (Left)	7,609,201	801.5	1,197	5,636,129	552.2	1,197
Governing Stage Shell (Left)	7,609,201	651.5	1,182	5,636,129	487.5	1,194

Location	Baseline (0% Thermal Extraction)			30% Thermal Extraction		
	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]
FWH6 Extraction Stage (Left)	6,808,507	296.5	1,132	4,939,882	219.7	1,145
HPT Exhaust (Left)	6,808,507	192.2	1,104	4,939,882	141.7	1,115
HPT Bowl (Right)	7,609,201	801.5	1,197	5,636,129	552.2	1,197
Governing Stage Shell (Right)	7,609,201	651.6	1,182	5,636,129	487.8	1,193
FWH7 + RH2 Extraction Stage (Right)	6,550,264	451.0	1,159	4,879,028	337.0	1,171
HPT Exhaust (Right)	6,550,264	192.2	1,104	4,879,028	141.7	1,115
LPT A Bowl	3,673,069	175.5	1,274	2,677,248	129.3	1,283
FWH4A Extraction Stage	3,470,241	92.3	1,219	2,479,494	66.5	1,226
FWH3A Extraction Stage	3,271,723	41.8	1,159	2,285,586	29.0	1,162
FWH2A Extraction Stage	3,075,061	16.4	1,106	2,108,017	11.2	1,108
MR (to FWH1A) Extraction Stage	3,015,812	10.2	1,088	2,069,513	7.0	1,089
FWH1A Extraction Stage	2,855,450	5.60	1,068	1,931,433	3.75	1,068
MR (to LPT A Exhaust) Extraction Stage	2,788,284	3.43	1,057	1,889,616	2.42	1,059
LPT A Exhaust	2,788,284	1.24	1,022	1,889,616	1.00	1,023
LPT B Bowl	3,673,069	175.7	1,274	2,677,248	129.4	1,283
FWH4B Extraction Stage	3,468,763	92.3	1,219	2,478,139	66.5	1,225
FWH3B Extraction Stage	3,273,638	41.8	1,159	2,287,097	29.0	1,162
FWH2B Extraction Stage	3,068,421	16.4	1,106	2,102,369	11.1	1,107
MR (to FWH1B) Extraction Stage	3,008,809	10.2	1,088	2,064,802	7.0	1,088
FWH1B Extraction Stage	2,847,364	5.58	1,068	1,924,897	3.74	1,067
MR (to LPT B Exhaust) Extraction Stage	2,780,228	3.42	1,057	1,882,541	2.42	1,059
LPT B Exhaust	2,780,228	1.38	1,023	1,882,541	1.07	1,024

Location	Baseline (0% Thermal Extraction)			30% Thermal Extraction		
	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]	Mass Flow [lbm/hr]	Pressure [psia]	Enthalpy [BTU/lbm]
LPT C Bowl	3,673,069	175.7	1,274	2,677,249	129.4	1,283
FWH4C Extraction Stage	3,473,448	92.4	1,219	2,482,813	66.6	1,226
FWH3CExtraction Stage	3,278,225	41.9	1,159	2,291,586	29.1	1,162
FWH2C Extraction Stage	3,070,612	16.4	1,106	2,103,231	11.1	1,107
MR (to FWH1C) Extraction Stage	3,011,389	10.2	1,088	2,064,763	7.0	1,089
FWH1C Extraction Stage	2,850,762	5.59	1,068	1,926,528	3.74	1,068
MR (to LPT C Exhaust) Extraction Stage	2,783,458	3.42	1,057	1,884,387	2.42	1,059
LPT C Exhaust	2,783,458	1.64	1,028	1,884,387	1.22	1,029

B6.0   REFERENCES

B6.1   Computer Code PEPSE™ (Performance Evaluation of Power System Efficiencies), Version 84.1 by Scientech Incorporated, S&L Program No. 03.7.551-84.0, Controlled File Path: C:\Program Files (x86)\Applist\PEP55184\

B6.2   STMFUNC, "Steam Table Function Dynamic Link Library," S&L Program Number 03.7.598-2.0

B7.0   EVALUATIONS

B7.1   H-S Diagram

Turbine performance can be visualized by plotting on an enthalpy-entropy chart (H-S). Figures B7-1 and B7-2 plot the design turbine performance at 100% and 75% thermal power along with the baseline and 30% extraction cases.
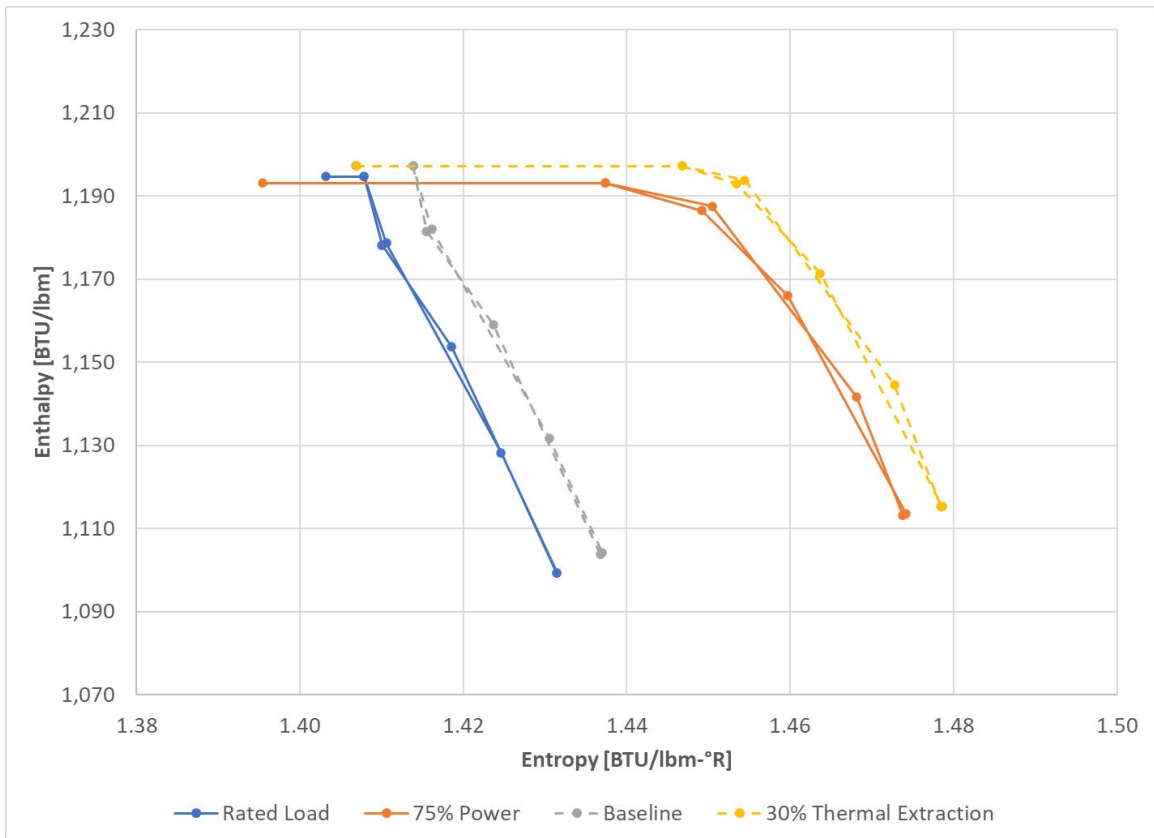
Figure B7-1: Enthalpy-Entropy Chart (HPT)
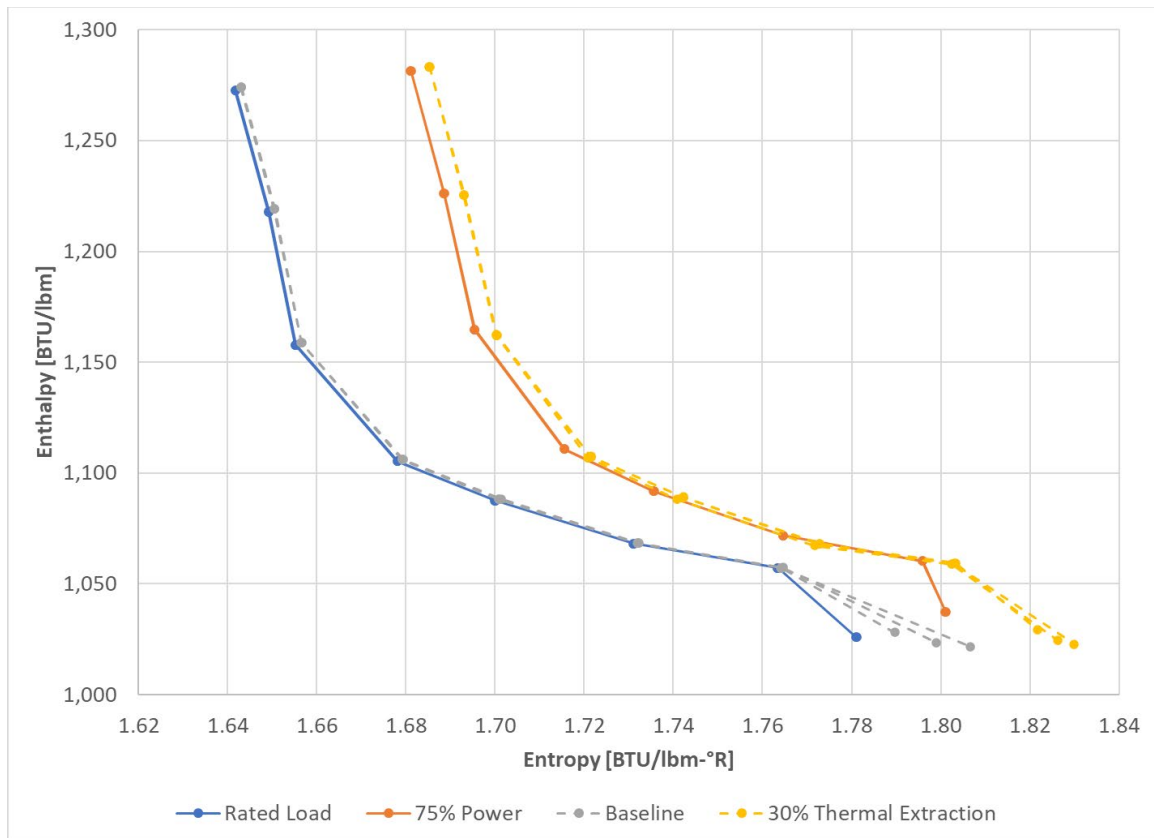
Figure B7-2: Enthalpy-Entropy Chart (LPT)

As shown in Figures B7-1 and B7-2, the Baseline turbine performance trends very closely to the Rated Load case. Similarly, the 30% Extraction turbine performance trends closely to the 75% Power case.

B7.2   Flow Comparison

Table B7-1 provides a comparison of the mass flow rates from baseline scenario to 30% power extraction.

Table B7-1 – Mass Flow Comparison

Location	Baseline (0% Thermal Extraction) [lbm/hr]	30% Thermal Extraction [lbm/hr]	Percent Change [-]
Throttle Valve Inlet	15,218,400	11,272,260	-26%
HPT Bowl (Left)	7,609,201	5,636,129	-26%
Governing Stage Shell (Left)	7,609,201	5,636,129	-26%
FWH6 Extraction Stage (Left)	6,808,507	4,939,882	-27%
HPT Exhaust (Left)	6,808,507	4,939,882	-27%
HPT Bowl (Right)	7,609,201	5,636,129	-26%
Governing Stage Shell (Right)	7,609,201	5,636,129	-26%
FWH7 + RH2 Extraction Stage (Right)	6,550,264	4,879,028	-26%

Location	Baseline (0% Thermal Extraction) [lbm/hr]	30% Thermal Extraction [lbm/hr]	Percent Change [-]
HPT Exhaust (Right)	6,550,264	4,879,028	-26%
LPT A Bowl	3,673,069	2,677,248	-27%
FWH4A Extraction Stage	3,470,241	2,479,494	-29%
FWH3A Extraction Stage	3,271,723	2,285,586	-30%
FWH2A Extraction Stage	3,075,061	2,108,017	-31%
MR (to FWH1A) Extraction Stage	3,015,812	2,069,513	-31%
FWH1A Extraction Stage	2,855,450	1,931,433	-32%
MR (to LPT A Exhaust) Extraction Stage	2,788,284	1,889,616	-32%
LPT A Exhaust	2,788,284	1,889,616	-32%
LPT B Bowl	3,673,069	2,677,248	-27%
FWH4B Extraction Stage	3,468,763	2,478,139	-29%
FWH3B Extraction Stage	3,273,638	2,287,097	-30%
FWH2B Extraction Stage	3,068,421	2,102,369	-31%
MR (to FWH1B) Extraction Stage	3,008,809	2,064,802	-31%
FWH1B Extraction Stage	2,847,364	1,924,897	-32%
MR (to LPT B Exhaust) Extraction Stage	2,780,228	1,882,541	-32%
LPT B Exhaust	2,780,228	1,882,541	-32%
LPT C Bowl	3,673,069	2,677,249	-27%
FWH4C Extraction Stage	3,473,448	2,482,813	-29%
FWH3CExtraction Stage	3,278,225	2,291,586	-30%
FWH2C Extraction Stage	3,070,612	2,103,231	-32%
MR (to FWH1C) Extraction Stage	3,011,389	2,064,763	-31%
FWH1C Extraction Stage	2,850,762	1,926,528	-32%
MR (to LPT C Exhaust) Extraction Stage	2,783,458	1,884,387	-32%
LPT C Exhaust	2,783,458	1,884,387	-32%

As shown in Table B7-1, the turbine experiences a ~26% to ~32% reduction in mass flow rate when operating with 30% thermal energy extracted for off-site use. Notably, the HPT interstage flows all decrease by a similar margin (~27%). This is important as the HPT is not symmetric, with FWH7 and 2nd Stage Reheat (RH2) extractions coming off the right side and FWH6 extraction coming from the left. Based on the consistent reduction in flow on either side, additional stress due to imbalanced loading on the turbine is not expected.

B8.0   RESULTS AND CONCLUSIONS

A review of the turbine performance modeled in PEPSE for baseline (0% thermal extraction) and 30% thermal energy extraction conditions shows good alignment with the design turbine performance at rated and 75% thermal power conditions. The turbine is expected to experience a reduction in mass flow rate of at least 25% when operating with 30% thermal energy extracted for off-site use. HPT flows are expected to reduce by a similar amount on either side of the HPT flow path. Therefore, additional stress due to imbalanced loading on the turbine is not expected.

Based on the review of the PEPSE heat balance conditions, the turbine is expected to operate within design for operation with up to 30% thermal energy extracted for off-site use. However, final acceptability of operation under this condition must be confirmed with the turbine vendor on a plant specific basis.

The turbine control system is expected to require changes to accommodate operation with thermal energy extracted for off-site use. The evaluation of, and potential changes to, turbine controls needs to be performed separately and is not within the scope of this assessment.

Attachment C – Condenser Evaluation

Prepared: Gabriel Neimark

Reviewed: Nic Richards

C1.0   PURPOSE

The purpose of this evaluation is to examine required duty and expected changes to operating conditions and performance parameters in relation to the design of the Main Condenser. These changes are due to steam extraction for supplying thermal energy off-site. These evaluations are done for the scenario where 30% thermal energy is extracted from main steam.

C2.0   SYSTEM & COMPONENT DESCRIPTION

The main condenser is the steam cycle heat sink. During normal operation it receives and condenses main turbine exhaust steam. Turbine bypass steam is also routed to the main condenser when required. The main condenser is also a collection point for other steam cycle miscellaneous flows, drains, and vents

Although there are three independent zones for steam flow, the condenser has a single pass of Circulating Water (CW). CW enters at the low pressure zone, passes through the intermediate pressure zone and exits at the high pressure zone. The cold surface of the stainless steel tubes condenses the steam into water, which is collected in the hotwell.

The purpose of the main condenser evacuation and off-gas system is to maintain a vacuum in the condenser and to remove noncondensable gas (including air inleakage and other noncondensable gases introduced to the condenser).

For the purpose of this assessment it is assumed that the main steam used for the 30% thermal extraction is condensed and routed back to the main condenser as shown on PEPSE Heat Balance diagrams documented in Attachment A.

C3.0   METHODOLOGY

The operating conditions of the main condenser are evaluated for the 30% thermal extraction scenario and compared to baseline operation. These operating conditions are taken from the PEPSE Heat Balance results documented in Attachment A. The results of this comparison are used to evaluate the impact on condenser thermal performance and flow-induced tube vibration.

The required air removal capacity is not specifically evaluated as, during power operation, the major sources of noncondensable gases in the main condenser are air leaks in the condenser shell, which is not expected to change for the 30% thermal extraction scenario.

C4.0   ASSUMPTIONS

C4.1   Circulating Water Conditions – The PEPSE results presented in Attachment A assume constant Circulating Water (CW) conditions (inlet temperature and flow rate) between the baseline and 30% thermal energy extraction cases. This is assumed for simplicity and is reasonable as thermal energy extraction is not expected to have any impact on CW availability.

C5.0   DESIGN INPUTS

Operating conditions are taken from the PEPSE Heat Balance results documented in Attachment A and presented in Table C7-1.

C6.0   REFERENCES

None

C7.0   EVALUATIONS

The condenser operating conditions for the baseline and 30% thermal extraction scenarios are compared in Table C7-1.

Table C7-1: Condenser Operating Conditions

Description	Units	0%	30%	Δ (30%)
Condenser A Shell Pressure	psia	1.24	1.01	-18.9%
Condenser A Shell Flow	lbm/hr	3,120,435	2,198,666	-29.5%
Condenser A Duty	BTU/hr	2.92E+09	2.11E+09	-27.8%
Condenser B Shell Pressure	psia	1.38	1.07	-22.5%
Condenser B Shell Flow	lbm/hr	2850639	1,928,182	-32.4%
Condenser B Duty	BTU/hr	2.64E+09	1.83E+09	-30.7%
Condenser C Shell Pressure	psia	1.64	1.22	-25.9%
Condenser C Shell Flow	lbm/hr	2,854,037	1,929,813	-32.4%
Condenser C Duty	BTU/hr	2.65E+09	1.85E+09	-30.4%
Hotwell Temperature	°F	115.6	105.1	-10.5°F
Condensate Flow	lbm/hr	11,334,490	11,723,820	3.43%

As shown in Table C7-1, with constant CW conditions, condenser backpressures decrease when thermal energy is extracted, so this scenario will not trigger a high backpressure alarm or exceed the turbine trip setpoint. Any limits on condensate hotwell temperature will not be challenged as this temperature decreases for the thermal extraction case. Decreased steam flow rates will also reduce the severity of flow-induced vibrations. Since the main steam used for the 30% thermal extraction is condensed and routed back to the main condenser there is a small increase in the total condensate flow. Additionally, since the overall condenser duty goes down with thermal energy extraction, the condenser's ability to accept turbine bypass steam is not affected.

C8.0   RESULTS AND CONCLUSIONS

An evaluation of condenser operating conditions shows that the condenser will continue to meet operation requirements for 30% thermal extraction conditions. Condenser steam flow rates, backpressures, and heat loads decrease for the thermal extraction case, so backpressure limits will not be challenged, and the severity of flow-induced vibrations will be reduced. Due to the additional condensate routed back to the main condenser there is a small increase in the total condensate flow.   Additionally, since the overall condenser duty goes down with thermal energy extraction, the condenser's ability to accept turbine bypass steam is not affected.

The evacuation capacity of the condensers is not affected by operating with 30% thermal extraction conditions.

Attachment D – Power Train Pumps Evaluation

Prepared: Gabriel Neimark

Reviewed: Nic Richards

D1.0   PURPOSE

The purpose of this evaluation is to examine the required duty and expected changes to operating conditions and performance parameters in relation to the power train pumps and drivers, consisting of the Condensate Pumps (CDPs), Condensate Booster Pumps (CBPs), Heater Drain Pumps (HDPs), and the Feedwater Pumps (FWPs). Changes to the heater drain tank level control valves are also evaluated. These changes are due to extracting steam from the nuclear power cycle main steam system to supply thermal energy to the plant boundary for off-site use. These evaluations are done for the scenario where 30% thermal energy is extracted.

D2.0   SYSTEM & COMPONENT DESCRIPTION

D2.1   System Description

The power conversion system is a closed cycle, with the CD, CB, and FW systems working to deliver water from the condenser hotwell to the four Steam Generators (S/Gs). The CDPs draw water from the condenser and pump it through the Steam Jet Air Ejector (SJAE) condensers and gland steam condensers (GSCs) to the CBPs. The booster pumps provide the required head to pump the condensate through the Low Pressure (LP) FW heaters and to provide sufficient suction head at the two Turbine Driven Feed Pumps (TDFPs). The water collected from the heater drains is stored in the Heater Drain Tank (HDT) and is forwarded into the CB system upstream of the 5th point heaters through the HDPs. In the FW system, the water is pumped through one stage of High Pressure (HP) FW heaters and then on to four S/Gs.

D2.2   Pump Description

The suction energy level of each pump is given in table D2-1. This is used in determining the Preferred Operating Region and minimum NPSH ratio acceptance criteria for the pumps in Section D3.3.

Table D2-1: CDP Best Efficiency Point

	Suction Energy Evaluation (Low / High / Very High)
CDP	High
CBP	Very High
FWP	Very High

D3.0   METHODOLOGY & ACCEPTANCE CRITERIA

D3.1   Methodology

The power train pump systems evaluated in this report are the CDPs, CBPs, FWPs, and the HDPs, along with the associated HD tank control valves. Each system is analyzed through the use of a generic Fathom hydraulic model of the CD, CB, HD forwarding, and FW systems.

The condenser pressure, FW flow, HD flow, and water temperatures are taken from the PEPSE Heat Balance results documented in Attachment A. Cases are run for 1) no thermal extraction, and 2) 30% thermal extraction.

D3.2   Computer Programs and Software

The hydraulic model used in this task report is created using Fathom Version 11.0 [Ref. D6.1]. Fathom is run on S&L PC 13857 under the Windows 10 operating system.

D3.3   Acceptance Criteria

D3.3.1 Condensate Pumps

a) Acceptance Criterion 3.3.1a: CDP Preferred Operating Region – Under normal operation, the CDPs should operate within the POR. Per HI Standards [Ref. D6.2], the POR for horizontal centrifugal pumps is between 70% and 120% of the BEP.

b) Acceptance Criterion 3.3.1b: CDP Driver Horsepower – The CDPs and CBPs are driven by a common motor, yet the CDPs operate at a lower speed and are driven by gearbox connected to the motor. The CDP brake horsepower (BHP) should not exceed the rated service horsepower of the gearbox.

c) Acceptance Criterion 3.3.1c: CDP NPSH Margin – Per Table 9.6.1.1 of the HI Standard 9.6.1 [Ref. D6.3], the guideline for the minimum NPSH margin ratio for high suction energy horizontal pumps in nuclear power applications is 2.0.

D3.3.2 Condensate Booster Pumps

a) Acceptance Criterion 3.3.2a: CBP Preferred Operating Region – Under normal operation, the CBPs should operate within the POR. Per HI Standards [Ref. D6.2], the POR for horizontal centrifugal pumps is between 70% and 120% of the BEP.

b) <u>Acceptance Criterion 3.3.2b: CBP Driver Horsepower</u> – The CBP is directly driven by the motor common to the CDPs and CBPs. The combined CDP and CBP BHP should not exceed the rated horsepower of this motor.

c) <u>Acceptance Criterion 3.3.2c: CBP NPSH Margin</u> – Per Table 9.6.1.1 of the HI Standard 9.6.1 [Ref. D6.3], the guideline for the minimum NPSH margin ratio for very high suction energy horizontal pumps in nuclear power applications is 2.5.

D3.3.3 <u>Heater Drain Tank Pumps (HDPs)</u>

a) <u>Acceptance Criteria 3.3.3a: Preferred Operating Region</u> – The HI Standard for the allowable operating region [Ref. D6.2] states that for a vertical pump the most conservative POR is between 80% and 115% of the BEP.

b) <u>Acceptance Criterion 3.3.3b: HDP Driver Horsepower</u> – The HDP BHP should not exceed the rated horsepower of its motor.

c) <u>Acceptance Criterion 3.3.3c: HDP NPSH Margin</u> – HI Standard 9.6.1 [Ref. D6.2] states that vertical turbine pumps are designed to withstand constant cavitation. Therefore, the minimum NPSH ratio for the HDPs should be 1.0, yet this evaluation will conservatively evaluate the pumps to a minimum NPSH ratio requirement of 2.0.

D3.3.4 <u>Turbine Driven Feed Pumps</u>

a) <u>Acceptance Criterion 3.3.4a: TDFP Preferred Operating Region</u> – The HI Standard for the allowable operating region [Ref. D6.2] states that the POR for a horizontal, centrifugal pump, is between 70% and 120% of the BEP.

b) <u>Acceptance Criterion 3.3.4b: TDFP Driver Horsepower</u> – The TDFP BHP should not exceed the rated horsepower of the turbine.

c) <u>Acceptance Criterion 3.3.4c: TDFP NPSH Margin</u> – Per Table 9.6.1.1 of the HI Standard 9.6.1 [Ref. D6.3], the guideline for the minimum NPSH margin ratio for very high suction energy horizontal pumps in nuclear power applications is 2.5.

d) <u>Acceptance Criterion 3.3.4d: Turbine Driven Feed Pump Speed</u> – The turbine should have sufficient margin below the overspeed setpoint for the TDFPs.

D3.3.5 <u>Control Valves</u>

a) <u>Acceptance Criterion 3.3.5a: HD Tank Level Control Valve Position</u> – The HD tank control valves operate together during normal conditions to control the HD pump flow, however it is required that one valve shall pass 100% of the HD flow with margin for control (< 80% open) in the event that one of the valves is failed closed. However, during normal operation with two valves, the valve position should not exceed 50% open.

D4.0 ASSUMPTIONS

D4.1 <u>Fugitive Flow</u> – An additional 1% of total FW flow is added to the analysis cases to account for flows which are present in the system, but do not reach the S/Gs. Fugitive flow represents any unaccounted flows (i.e., valve leakage) and adds conservatism to the calculation. The fugitive flow is removed from the FW system at the feed pump discharge.

D5.0 DESIGN INPUTS

D5.1 <u>Operating Temperatures and Flows</u> – The FW flow, HD Pump flow, condenser backpressure, and fluid temperatures are taken from the PEPSE Heat Balance results given in Attachment A. The parameters used as input to the hydraulic model are listed below in Table D5-1.

Table D5-1: PEPSE Input

Description	Units	0%	30%	Δ (30%)
DC 1A Discharge Temp	°F	126.3	113.3	-13.0°F
FWH 1A Discharge Temp	°F	161.1	144.2	-16.9°F
FWH 2A Discharge Temp	°F	210.1	189.9	-20.2°F
FWH 3A Discharge Temp	°F	263.1	241.3	-21.8°F
FWH 4A Discharge Temp	°F	314.3	291.3	-23.0°F
DC 5A Discharge Temp	°F	331.4	306.0	-25.5°F
FWH 5A Discharge Temp	°F	369.9	345.6	-24.3°F
FWH 5A Extraction Pressure	psia	186.1	137.1	-26.3%
FWH 6A Discharge Temp	°F	409.5	383.5	-25.9°F
FWH 7A Discharge Temp	°F	440.2	412.7	-27.5°F
DC 1B Discharge Temp	°F	126.6	113.5	-13.1°F
FWH 1B Discharge Temp	°F	161.7	144.8	-16.9°F
FWH 2B Discharge Temp	°F	212.8	192.6	-20.2°F
FWH 3B Discharge Temp	°F	265.0	243.3	-21.7°F

Description	Units	0%	30%	Δ (30%)
FWH 4B Discharge Temp	°F	316.4	293.5	-22.9°F
DC 5B Discharge Temp	°F	332.2	306.8	-25.4°F
FWH 5B Discharge Temp	°F	370.2	345.9	-24.3°F
FWH 5B Extraction Pressure	psia	186.1	137.1	-26.3%
FWH 6B Discharge Temp	°F	409.7	383.7	-25.9°F
FWH 7B Discharge Temp	°F	441.5	413.8	-27.7°F
DC 1C Discharge Temp	°F	125.9	113.0	-13.0°F
FWH 1C Discharge Temp	°F	160.8	143.9	-16.9°F
FWH 2C Discharge Temp	°F	212.7	192.5	-20.3°F
FWH 3C Discharge Temp	°F	264.6	242.9	-21.7°F
FWH 4C Discharge Temp	°F	315.0	292.0	-22.9°F
Average Condenser Pressures	in HG	2.89	2.24	-22.7%
Condensate Temperature	°F	115.6	105.1	-10.5°F
SJAE Outlet Temp	°F	115.8	105.3	-10.5°F
GSC Outlet Temp	°F	116.4	105.9	-10.5°F
FW Flow[1]	lbm/hr	16,067,280	15,466,190	-3.7%
HDT Temp	°F	336.6	307.7	-28.8°F
HD Flow	lbm/hr	4,732,792	3,742,365	-20.9%
HDT Pressure	psia	185.13	136.46	-26.3%

1)   PEPSE flows do not include the 1% fugitive flow (see Assumption 4.1). Actual flows input to each feed pump are documented in Table D5-2.

D5.2   <u>Feed Pump Flow</u> - Based on the fugitive flow assumption (Assumption 4.1), Table D5-2 reports the actual flow values input to the FWPs for each case.

Table D5-2: Feed Pump Flows

	0%	30%
Final FW Flow (lbm/hr)	16,067,280	15,466,190
Fugitive Flow (lbm/hr)	160,673	154,662
Total Pump Flow (lbm/hr)	16,227,953	15,620,852
Flow per Pump (lbm/hr)	**8,113,976**	**7,810,426**

D6.0   REFERENCES

D6.1   AFT Fathom™, Version 11.0, "Computer Software for Modeling Incompressible Flow in Pipe Networks," S&L Program No. 03.7.721-11.0

D6.2   ANSI/HI 9.6.3-1997, 'American Nation Standard for Centrifugal/Vertical Pumps – Allowable Operating Region,' *Hydraulic Institute*, Parsippany, NJ.

D6.3   ANSI/HI 9.6.1-1998, "American National Standard for Centrifugal and Vertical Pumps for NPSH Margin," *Hydraulic Institute*, Parsippany, NJ.

D7.0   EVALUATIONS

This section compares the model results for the 0% and 30% thermal extraction cases.

D7.1   Evaluation of the Preferred Operating Region

Centrifugal pumps are optimized for performance and service life at the BEP. At the BEP, hydraulic efficiency is maximized with flow entering the impeller vanes in a shockless manner. Within the POR of the pump, the flow is well controlled, and the pump will not be significantly affected by hydraulic loads, vibration, or flow separation [Ref. D6.2].

Table D7-1: Evaluation of Preferred Operating Region

Pump	Acceptance Criteria	0%	30%	Δ (30%)
CDP	70% - 120%	109.6	113.0	3.1%
CBP	70% - 120%	114.3	117.8	3.1%
TDFP	70% - 120%	99.1	95.2	-3.9%
HDP	80% - 115%	102.8	79.9	-22.3%

For the CDPs, CBPs, and TDFPs, the percent BEP remains within the associated POR, and changes from the base scenario to the 30% extraction case are minimal. The HDPs experience a significant change in operating point and will have to be evaluated on a plant-specific basis. However, it is not expected that any equipment changes will be required.

D7.2   Evaluation of Pump Driver Duty

The power requirement for each pump to perform as hydraulically characterized in the Fathom model is reported as part of the pump performance results. The calculated BHP of the pump must not exceed the rated horsepower of the associated driver, which is a motor and gearbox for the CDPs, a motor for the CBPs, a separate motor for the HDPs, and turbines for FWPs "B" and "C". The duty on the CDP/CBP motor is taken as the sum of the CDP and CBP required BHP, as the motor must supply enough power to drive both pumps.

Table D7-2: Evaluation of Pump Driver Duty (hp)

Pump	0%	30%	Δ (30%)
CDP Gearbox	664	680	2.3%
CDP/CBP Motor	3157	3224	2.1%
TDFP Turbine	8590	8170	-4.9%
HDP Motor	1894	1877	-0.9%

The duty on the CDP gearbox and CDP/CBP motor increases slightly for the 30% extraction case. These will need to be evaluated against the rated horsepower of their associated drivers. The duty on the TDFP turbine and HDP motor decreases and should continue to meet the acceptance criteria for the 30% extraction case.

D7.3   Evaluation of Net Positive Suction Head Ratio

The NPSH ratio (NPSHa/NPSHr) is a measure of the available suction head margin for a pump. The NPSHa is the net positive suction head available to a pump. The NPSHr of a pump is defined as the NPSH that will cause the total head of the pump to be reduced by 3%, due to flow blockage from cavitation vapor in the impeller vanes [Ref. D6.3]. In order to limit noise, vibration, and overall reliability, minimum NPSH ratios for each pump are established as acceptance criteria, per the guideline values in Table 9.6.1.1 of the *Hydraulic Institute Standard on Centrifugal and Vertical Pumps for NPSH Margin* [Ref. D6.3]. The required NPSH ratio for the horizontal pumps (CDP, CBP, and FWP) is determined based on the pump suction energy level. Pumps with high suction energy require higher NPSH margins than those with low suction energy. As shown in the pump descriptions (see Section D2.2), the CDPs have high suction energy, while the CBPs and FWPs have very high suction energy. Vertical pumps often operate without NPSH margin, and only require that the NPSHa exceed the NPSHr. Though vertical pumps require an NPSH ratio of 1, a general acceptance criteria for of 2.0 is used for conservatism.

Table D7-3: Evaluation of NPSH Ratio

Pump	HI / ANSI Guideline	0%	30%	Δ (30%)
CDP	≥ 2.0	1.86	1.76	-5.5%
CBP	≥ 2.5	2.86	2.39	-16.5%
TDFP	≥ 2.5	2.42	3.55	46.7%
HDP	≥ 2.0	16.27	16.13	-0.9%

The NPSH ratio for the TDFPs significantly improves, and while the NPSH ratio decreases for the HDPs, this change is small. The CDP NPSH ratio is below the HI/ANSI guideline for both cases, but it is not expected that thermal extraction will significantly increase the risk of cavitation since the change from the baseline scenario is relatively small (~5.5%). The NPSH ratio for CBPs decreases more significantly (over 16%) and it falls below the guideline for the 30% extraction case. Therefore, although no physical changes are expected to the CDPs, CBPs, and HDPs, they should be evaluated for acceptance on a plant-specific basis for the 30% extraction case.

D7.4 Evaluation of Pump Suction and Discharge Pressure

Suction and discharges pressures for each pump are compared in Tables D7-4 and D7-5. This evaluation is used to see which pumps may be at risk of falling below alarm setpoints.

Table D7-4: Pump Suction Pressures (psig)

Pump	0%	30%	Δ (30%)
CDP	-5.1	-5.5	-3.9%
CBP	99.2	94.9	-3.8%
TDFP	425.0	412.3	-2.9%
HDP	184.8	136.5	-24.2%

Table D7-5: Pump Discharge Pressures (psig)

Pump	0%	30%	Δ (30%)
CDP	129.5	127.1	-1.6%
CBP	584.3	570.3	-2.3%
TDFP	1130.5	1122.1	-0.7%
HDP	696.1	763.6	9.5%

Overall, suction and discharge pressures decrease for the 30% thermal extraction case. Suction pressures will need to be evaluated on a plant-specific basis to ensure that they do not fall below low alarm setpoints.

D7.5   Evaluation of Turbine Driven Feedwater Pump Speed

The FW flow through the pumps is regulated by the speed of the driving turbine, which receives steam from the main steam system. In the Fathom model, the turbine speed is calculated based on the required flow and developed head required of the TDFPs.

Table D7-6: Evaluation of FWP Turbine Speed (rpm)

	0%	30%	Δ (30%)
Max Calculated Turbine Speed	5,022	4,934	-1.8%

The max calculated turbine speed decreases, so the margin improves for the 30% extraction case and should not challenge the acceptance criteria for TDFP speed.

D7.6   Evaluation of Heater Drain Tank Level Control Valves

The heater drain tank level control valves are evaluated for controlling margin. Acceptable control margin corresponds to a valve position of less than 50% open, so that each operating valve maintains the ability to pass all of the drain flow.

Table D7-7: Heater Drain Level Control Valve Evaluation

	Acceptance Criteria	Valve Position (% Open)		Δ (30%)
		0%	30%	
HD Level Control Valve	≤ 50%	26.0	16.9	-35.1%

Based on these results, the HD tank level control valves meet the acceptance criteria, and the margin improves for the 30% extraction case.

D8.0   RESULTS AND CONCLUSIONS

Analysis of the power train pumps for the 30% thermal extraction scenario shows that overall, changes from the baseline operating conditions are minimal. Pump operating point changes by less than 5% for all pumps except for the heater drain pumps which see a reduction in percent BEP of ~22%. It is not expected that any equipment changes will be needed to address this, but the HDPs will have to be evaluated with plant-specific operating conditions and design margins. Changes to pump driver duty are also small. However, the duty on the CDPs and CBPs increase and will need to be evaluated against the rated horsepower of their associated drivers on a plant-specific basis. The CBPs also require plant-specific evaluation due to a ~17% decrease in NPSH ratio. The CDP and HDPs NPSH ratios are also decreasing by a small amount. The NPSH ratio for the TDFPs significantly improves. Therefore, although no physical changes are expected the CDPs, CBPs, and HDPs, they should be evaluated for acceptance on a plant-specific basis for the 30% extraction case.

Pump suction pressures decrease for all power train pumps and will need to be evaluated against existing low alarm setpoints on a plant-specific basis.

The feedwater and heater drain flows are reduced, so margins for the feedwater pump turbine speed and heater drain tank level control valves improve for the thermal extraction case.

Attachment E – Moisture Separator Reheater Evaluation

Prepared: Gabriel Neimark

Reviewed: Nic Richards

E1.0   PURPOSE

The purpose of this evaluation is to examine expected changes to operating conditions of the Moisture Separator Reheaters (MSRs). These changes are due to steam extraction for supplying thermal energy off-site. This evaluation is done for the scenario where 30% thermal energy is extracted from the main steam.

E2.0   SYSTEM & COMPONENT DESCRIPTION

The MSRs take wet exhaust steam from the High Pressure Turbine (HPT) and pass it through a series of chevrons to remove moisture. The steam then goes through two stages of heat exchangers where it is heated before being sent to the Low Pressure Turbines (LPTs).

E3.0   METHODOLOGY

The operating conditions of the MSRs are evaluated for the 30% thermal extraction scenario and compared to baseline (0% thermal extraction) operation. These operating conditions are taken from the PEPSE Heat Balance results documented in Attachment A. Evaluation of the MSR drains is done in Attachment H.

E4.0   ASSUMPTIONS

None

E5.0   DESIGN INPUTS

Operating conditions are taken from the PEPSE Heat Balance results documented in Attachment A and presented in Table E7-1.

E6.0   REFERENCES

None

E7.0   EVALUATIONS

The MSR operating conditions for the baseline and 30% thermal extraction scenarios are compared in Table E7-1.

Table E7-1: MSR Operating Conditions

Description	Units	0%	30%	Δ (30%)
MSR Removal Effectiveness	-	0.95	0.95	0.00%
MSR Chevrons Inlet Flow	lbm/hr	3,151,396	2,266,680	-28.1%
MSR Chevrons Inlet Enthalpy	BTU/lbm	1,104	1,115	1.02%
MSR Chevrons Inlet Pressure	psia	190.3	140.2	-26.3%
MSR 1st Stage Inlet Enthalpy	BTU/lbm	1,193	1,189	-0.31%
MSR 1st Stage Inlet Pressure	psia	184.6	136.0	-26.3%

Description	Units	0%	30%	Δ (30%)
MSR 2nd Stage Inlet Enthalpy	BTU/lbm	1,227	1,222	-0.41%
MSR 2nd Stage Inlet Pressure	psia	181.8	134.0	-26.3%

As shown in Table E7-1, flow to the MSRs and the pressure at each stage is reduced for the 30% thermal extraction case, with minimal change in enthalpies. Therefore, it is not expected that the MSRs will be negatively impacted by operating with thermal extraction conditions. The ~28% reduction in mass flow results in conditions similar to normal 75% thermal power with no thermal energy extraction.

E8.0   RESULTS AND CONCLUSIONS

The moisture separator reheaters will not be affected by operating under thermal extraction conditions. Pressures and steam flows decrease such that operating conditions are similar to 75% thermal power conditions which is an acceptable operating point for the MSRs.

Attachment F – Feedwater Heater Evaluation

Prepared: Gabriel Neimark

Reviewed: Nic Richards

F1.0   PURPOSE

The purpose of this evaluation is to examine required duty and expected changes to operating conditions and performance parameters in relation to the design of the Feedwater Heaters. These changes are due to extracting steam from the nuclear power cycle main steam system to supply thermal energy to the plant boundary for off-site use. These evaluations are done for the scenario where 30% thermal energy is extracted.

F2.0   SYSTEM & COMPONENT DESCRIPTION

The Condensate (CD) and Feedwater (FW) Systems deliver feedwater (condensed steam) to the steam generators. The CD system first directs flow through three parallel strings of low pressure feedwater heaters (1st point external drain cooler and 1st through 4th point heaters). Flow then passes through two parallel strings of low pressure feedwater heaters (5th point external drain cooler, 5th and 6th point heaters) to the turbine driven steam generator feed pumps (SGFP). FW flow then continues through two parallel high pressure feedwater heaters (7th point heaters) to the steam generators. The feedwater heaters receive extraction steam flow and moisture separator reheater drain flow from the main turbine system.

F3.0   METHODOLOGY AND ACCEPTANCE CRITERIA

F3.1   Methodology

F3.1.1 Tube Side Nozzle Velocity

The water velocity in these nozzles must be limited to minimize metal erosion in the head and tube sheet areas caused by feedwater impingement. The velocity used with the HEI guidelines [Ref. F6.2] is based on the density of liquid water at 60°F.

F3.1.2 Tube Velocity

In order to avoid excessive tube erosion, the tube velocity should be limited. The flow area is based on the total number of tubes for each pass minus the number of plugged tubes. In accordance with HEI guidelines [Ref. F6.2], the density used in computing the tube velocity is based on the density of liquid water at the average tube temperature.

F3.1.3 Tube Side Pressure Drop and Partition Plate Differential Pressure

The tube side pressure drop principally affects two design issues, (i) the differential pressure across the pass partition plate (PPP), and (ii) the total pressure drop in the feedwater train. The pass partition plate is integral to the head of the feedwater heater, and separates the fluid entering the first tube pass from the fluid exiting the second tube pass. Moderately high differential pressures across the PPP can cause cracking of the welds in the plate or displacement of the partition gasket, which results in leakage and reduced heater performance. No guidelines are stated in HEI for the differential pressure across the PPP. Additional pressure loss in the feedwater train impacts the power train pumps, which are evaluated in Attachment D.

HEI [Ref. F6.2] provides an approximate method of calculating total tube side pressure drop, which consists of the sum of the following terms (see definitions below):

$$\Delta P_{total} = \Delta P_{tubes} + \Delta P_{NI} + \Delta P_{NO} + \Delta P_E \qquad \text{(Eq. F3-1)}$$

where:

ΔP_{total} — total tube side pressure drop, psid

ΔP_{tubes} — pressure loss through tubes, psid

ΔP_{NI} — pressure loss through channel inlet nozzle, psid

ΔP_{NO} — pressure loss through channel outlet nozzle, psid

ΔP_E — tube entrance, exit, and turning losses, psid

Pressure loss across inlet channel and outlet nozzle do not impact the pressure loss across the pass partition plate. Therefore, only the pressure loss through the tubes and the tube entrance, exit, and turning losses impact the PPP pressure drop.

These pressure drops are defined as follows from the HEI standards [Ref. F6.2]:

ΔP Inside Tubes

$$\Delta P_{tubes} = \frac{1.396 x 10^{-7}}{C} \cdot f \cdot \left(\frac{w}{A_t}\right)^2 \cdot \frac{L}{d} \qquad \text{(Eq. F3-2)}$$

where:

$$f = 0.0014 + 0.125 \cdot Re^{-0.32}$$

$$Re = \frac{w \cdot d}{0.201389 \cdot \mu \cdot A_t}$$

Tube Entrance, Exit, and Turn Losses

$$\Delta P_E = \frac{2.896 x 10^{-9}}{C} \cdot K_t \cdot \left(\frac{w}{A_t}\right)^2 \cdot \frac{N}{2} \qquad \text{(Eq. F3-3)}$$

where:

w   - feedwater mass flow rate, lb_m/hr

L - total length of tube travel, ft

A_t - flow area of tubes per pass accounting for tube plugging, in^2

d - nominal inside diameter of tubes, in

C - density correction factor from Fig. 3a [Ref. F6.2]

f - friction factor

K_t - loss correction factor for tube configuration from Fig. 3b [Ref. F6.2]

N - number of tube passes

Re - Reynolds number for individual tube at calculated flow rate per tube

μ - tube side absolute viscosity, centipoise

Review of Equations F3-2 and F3-3 show most factors are based on the physical design of the FWH and are not sensitive to changes in operating conditions. The density correction factor and friction factor are slightly impacted, but over the range of operating conditions expected, the impact is inconsequential compared to the change in feedwater mass flow rate (which is a squared term). Therefore, to review the impact on PPP pressure loss, only the change in mass flow rate squared is reviewed.

F3.1.4   Steam Inlet and Drain Outlet Nozzle Velocity

Steam velocities entering the shell side of the heater must be limited in order to prevent over-stressing of the impingement plate, erosion damage (i.e., to the impingement plate, tube support plates, and heater shell) and to control vibration of the tubes in the high velocity regions where steam is introduced to the tube bundle. Steam velocity is based on the fluid conditions from the heat balance, and it is compared against the recommended limit from the HEI standard [Ref. F6.2].

The steam velocity entering the heater is the mass flow rate of steam entering the heater from the heat balance, divided by the density of the steam, divided by the flow area of a single steam inlet nozzle, divided by the number of steam inlet nozzles per heater.

The velocity in the condensate drain outlet nozzle is calculated as the mass flow rate from the heat balance, divided by the density of liquid discharging from the heater, divided by the flow area of the drain nozzle.

F3.1.5   Drain Inlet Nozzle Mass Flux

The limits for this parameter are provided to minimize and/or avoid the following:

- erosion of the inlet nozzle and heater shell areas adjacent to the nozzle,
- structural damage to the impingement plate and adjacent tube support plates,
- tube degradation in the areas adjacent to the impingement plate, and
- vibration of tubes in high velocity regions where the two-phase mixture is introduced to the tube bundle.

HEI characterizes the inlet conditions through the use of a mass flux parameter, which is equal to the square of the mass flux rate divided by the fluid inlet density. The density is evaluated using the inlet enthalpy and heater shell pressure from the heat balance.

F3.1.6 Operating Pressure and Temperature

Tube side and shell side operating temperatures and shell side pressures for the baseline and 30% thermal extraction case are compared to determine the impact on design value margin. These parameters are taken from the heat balances in Attachment A.

F3.1.7 Drain Cooler Tube Vibration

The main sources of vibration in drain coolers are vortex shedding and fluidelastic whirling [Ref. F6.3]. In order to prevent resonant tube vibration from vortex shedding, the natural frequency of the unsupported tube span should remain larger than the vortex shedding frequency. TEMA requires that the natural frequency exceed the vortex shedding frequency. The natural frequency of the tube span is dependent on the physical design of the FWH and is therefore not impacted by changes to operating conditions associated with operating with thermal power extraction. The vortex shedding frequency is proportional to the cross flow velocity at the tubes. Since the cross flow area will not change with thermal power extraction, the total volumetric drain cooler flow is reviewed for changes due to operation with 30% thermal energy extraction.

Another possible mechanism for vibrational damage is fluidelastic whirling. This process occurs when the displacement of one tube alters the flow field resulting in forces on other tubes. If the exciting force from the flowing fluid exceeds damping, the self-excited vibration will set up. In order to prevent this excitation, the critical whirling velocity must exceed the cross flow velocity. The critical velocity is calculated using the methodology of TEMA [pages 94 & 95, Ref. F6.3].

A review of the TEMA equations shows that the critical velocity is based on physical parameters with a minor relationship to density. As the density is not significantly changing in the drain cooler due to operation with thermal power extraction, critical velocity can be considered constant for the purposes of this evaluation. Therefore, as with vortex shedding, only the cross flow velocity will be impacted by reviewing the total volumetric drain cooler flow changes due to operation with 30% thermal energy extraction.

F3.2 Acceptance Criteria

F3.2.1 Acceptance Criterion 1 – Tube side nozzle velocity should be less than 10 ft/s, according to HEI [Ref. F6.2].

F3.2.2 Acceptance Criterion 2 – Tube velocity should be less than 10 ft/s, according to HEI [Ref. F6.2].

F3.2.3 Acceptance Criterion 3 – Steam inlet nozzle velocity should be less than the HEI recommendation:

$$V \leq \frac{250}{P_{STEAM}^{0.09}}$$

(Eq. F3-4)

F3.2.4   Acceptance Criterion 4 – Condensate drain outlet velocity should be less than the HEI recommendation [Ref. F6.2] as follows:

- 4 ft/sec for sub-cooled drains,
- 4 ft/sec for saturated drains with level control in the heater, and
- 2 ft/sec for saturated drains where the level is not controlled in the heater

Velocity in the heater drain outlet nozzle must be limited to (a) avoid excessive drag loads on drain cooler tubes in the vicinity of the nozzle, and (b) prevent flashing in the downstream piping connected to the heater outlet nozzle.

F3.2.5   Acceptance Criterion 5 – Drain inlet nozzle mass flux G should be limited to the following according to HEI [Ref. F6.2]:

$$G \leq 250 \text{ lb}_m/\text{sec/ft}^2 \qquad\qquad \textit{(Eq. F3-5)}$$

$$\frac{G^2}{\rho} \leq 4000 \text{ lb}_m/\text{ft/sec}^2 \qquad\qquad \textit{(Eq. F3-6)}$$

F3.2.6   Acceptance Criterion 6 – In order to be acceptable for tube vibration, the following criteria must be met:

- f_n/f_e > 1, in order to prevent resonant vortex shedding frequencies [Ref. F6.3]
- V_{crit}/V > 1, in order to prevent excessively large vibration amplitudes [Ref. F6.3]

As discussed in Section F3.1.7, the natural frequency and critical velocity can be considered constant relative to changes in operating conditions. Similarly, the vortex shedding frequency and cross flow velocity are directly proportional to drain cooler volumetric flow. Therefore, if drain cooler volumetric flow decreases, margins to the ratio criteria will increase.

F4.0   ASSUMPTIONS

None.

F5.0   DESIGN INPUTS

F5.1   Operating Conditions – Mass flow rates, pressures, temperatures, and enthalpies for various operating parameters are taken from the PEPSE results given in Attachment A.

F5.2   Feedwater Heater Tubes – The number of tubes, tube dimensions, total length of tube travel, design tube pressure drop, and percent tube plugging are given in Table F5-1 based on typical plant data.

Table F5-1: FWH Tube Side Dimensions

Heater Nos	# of Tubes	Tube Size	Thickness (in)	Tube I.D. (in)	Total Tube Length (ft)	Pressure Drop (psi)	Tube Plugging (-)
1st EDC	396	1	0.035	0.930	15' 5"	6.6	15%
1st Point	1201	5/8	0.035	0.555	33' 8"	15	5%
2nd Point	797	3/4	0.035	0.680	46' 11"	15.7	5%
3rd Point	767	3/4	0.035	0.680	42' 7"	15.1	5%
4th Point	673	7/8	0.035	0.805	39' 7"	8.6	5%
5th EDC	2798	5/8	0.035	0.555	13' 8"	3.1	15%
5th Point	1842	3/4	0.035	0.680	29' 3"	10.5	5%
6th Point	2037	3/4	0.035	0.680	33' 3"	9.4	5%
7th Point	3583	5/8	0.058	0.509	24' 2"	10.9	5%

F5.3   Nozzle Sizes – The heater nozzle dimensions and the number of nozzles of each type are given in Table F5-2 based on typical plant data.

Table F5-2: FWH Nozzle Sizes

Heater Nos	Feedwater Inlet Nozzles		Feedwater Outlet Nozzles		Extraction Steam Nozzles			Inlet Drain Nozzles		Outlet Drain Nozzles	
	Dia (in)	I.D. (in)	Dia (in)	I.D. (in)	Qty.	Dia (in)	I.D. (in)	Dia (in)	I.D. (in)	Dia (in)	I.D. (in)
1st EDC	18"	16.12	18"	16.12	-	-	-	18"	17.250	18"	17.25
1st Point	18"	16.12	18"	16.12	4	30"	29.00	-	-	10"	10.02
2nd Point	18"	16.12	18"	16.12	2	28"	27.00	12"	11.750	14"	13.25
3rd Point	18"	16.12	18"	16.12	2	18"	17.00	8"	7.625	12"	12.00
4th Point	18"	16.12	18"	16.12	1	20"	19.00	-	-	8"	7.98
5th EDC	24"	21.56	24"	21.56	-	-	-	30"	29.250	30"	29.25
5th Point	28"	26.13	28"	26.13	1	22"	20.25	See Note 1	See Note 1	26"	25.25
6th Point	28"	26.13	28"	26.13	1	18"	16.88	18"	17.00	20"	19.25
7th Point	28"	25.4	24"	20.4	1	14"	13.12	10" (x2)	9.562	18"	17.25

[1] The fifth point FWHs have an 18-inch nozzle for cascading FWH drains (ID = 17.000") and two 8-inch nozzle for drains from each first stage reheater drain tank (ID = 7.625").

F6.0   REFERENCES

F6.1   STMFUNC (Steam Table Function Dynamic Link Library) S&L Program Number 03.7.598 2.0, dated 06-11-2018.

F6.2   Standards for Closed Feedwater Heaters. Heat Exchange Institute, Inc. Sixth Edition, 1998.

F6.3   Standards of the Tubular Exchanger Manufacturers Association, Tubular Exchanger Manufacturers Association, Inc. Seventh Edition, 1988.

F7.0   EVALUATIONS

F7.1   Evaluation of Condensate/Feedwater Nozzle Velocities

The following channel end nozzle velocities were computed for the feedwater heaters.

Table F7-1: Condensate/Feedwater Heater Nozzle Velocities (ft/s)

FW Heater	HEI Limit	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	10	11.9	12.3	3.4%
1st Point	10	11.9	12.3	3.4%
2nd Point	10	11.9	12.3	3.4%
3rd Point	10	11.9	12.3	3.4%
4th Point	10	11.9	12.3	3.4%
5th EDC	10	10.0	10.3	3.4%
5th Point	10	9.6	9.2	-3.7%
6th Point	10	9.6	9.2	-3.7%
7th Point Inlet	10	10.2	9.8	-3.7%
7th Point Outlet	10	15.8	15.2	-3.7%

Tube side nozzle velocities exceed the HEI guidelines for the several of the FWHs but changes from the baseline case are small or decrease, and it is not expected that feedwater nozzle wear will be an issue due to these changes.

F7.2   Evaluation of Tube Velocities

The following tube velocities were computed for the feedwater heaters. They are based on the density using the average tube temperature.

Table F7-2: Tube Velocity (ft/s)

FW Heater	HEI Limit	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	10	10.7	11.0	3.1%
1st Point	10	8.9	9.2	3.0%
2nd Point	10	9.1	9.3	2.7%
3rd Point	10	9.6	9.9	2.5%
4th Point	10	8.1	8.2	2.2%
5th EDC	10	7.0	7.1	2.0%
5th Point	10	9.1	8.6	-5.2%
6th Point	10	8.5	8.0	-5.4%
7th Point	10	8.8	8.3	-5.8%

Tube velocities remain below or marginally exceed the HEI guidelines for the 30% thermal extraction case. Because changes are small, it is not expected that this will impact FWH tube degradation.

F7.3   Tube Side Pressure Drop

The following change in mass flow rates are used to evaluate the impact on PPP pressure loss based on the methodology outlined in Section 3.1.3. As the mass flow rate term is squared in the pressure loss equations, the ratio of flow rates is squared to determine the percent change in PPP pressure drop.

Table F7-3: Pass Partition Plate Pressure Loss

FW Heater	Baseline (0% Extraction) (lbm/hr)	30% Extraction (lbm/hr)	Ratio of Flow Rates (30%/Baseline)	Ratio of Flow Rates Squared (30%/Baseline)^2	PPP dP % Change
1st EDC	3,778,163	3,907,940	103%	107%	7.0%
1st Point	3,778,163	3,907,940	103%	107%	7.0%
2nd Point	3,778,163	3,907,940	103%	107%	7.0%
3rd Point	3,778,163	3,907,940	103%	107%	7.0%
4th Point	3,778,163	3,907,940	103%	107%	7.0%
5th EDC	5,667,245	5,861,910	103%	107%	7.0%
5th Point	8,033,640	7,733,095	96%	93%	-7.3%
6th Point	8,033,640	7,733,095	96%	93%	-7.3%
7th Point	8,033,640	7,733,095	96%	93%	-7.3%

The pressure loss across the PP is expected to increase in FWHs 1 through 4 and both external drain coolers. However, the expected increase in tube side pressure drop for the thermal extraction case is not expected to appreciably impact reliable operation of the heaters.

F7.4 **Steam Inlet and Drain Outlet Nozzle Velocity**

The following steam inlet and drain outlet nozzle velocities were computed for the feedwater heaters.

Table F7-4: Steam Inlet Nozzle Velocity (ft/s)

FW Heater	HEI Limit	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st Point	215	137	181	32.6%
2nd Point	195	148	206	38.9%
3rd Point	179	179	249	39.1%
4th Point	167	156	214	37.5%
5th Point	156	101	115	37.2%
6th Point	150	103	139	19.8%
7th Point	146	80	123	5.39%

Table F7-5: Drain Outlet Nozzle Velocity (ft/s)

FW Heater	HEI Limit	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	4.0	2.3	2.1	-9.13%
1st Point	4.0	1.8	1.5	-20.2%
2nd Point	4.0	2.9	2.7	-5.49%
3rd Point	4.0	2.4	2.3	-3.27%
4th Point	4.0	2.8	2.7	-3.63%
5th EDC	4.0	1.8	1.5	-14.1%
5th Point	4.0	2.5	2.1	-14.3%
6th Point	4.0	2.7	2.3	-13.7%
7th Point	4.0	2.2	1.9	-13.6%

Steam inlet nozzle velocities for the thermal extraction case increase for all FWHs and exceed the HEI guideline for the 2nd, 3rd and 4th point heaters. Shell wear rates will likely increase, and it should be noted that changes to steam inlet velocity can affect the wear pattern of the shell, and future inspections should be mindful for changes.

Drain outlet velocities decrease for the thermal extraction case, so HEI guidelines are not challenged, and wear rates may decrease.

F7.5   Drain Inlet Nozzle Mass Flux

The mass flux and mass flux parameter of flashing condensate flows entering the shell side of the feedwater heaters are as follows:

Table F7-6: Heater Drain Inlet Nozzle Mass Flux and Mass Flux Parameter

FW Heater	Mass Flux (lbm/s/ft^2)				Mass Flux Parameter (lbm/ft/s^2)			
	HEI Limit	Baseline (0% Extraction)	30% Extraction	Δ (30%)	HEI Limit	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	250	141	129	-8.9%	4,000	4,755	4,110	-13.6%
2nd Point	250	148	144	-2.4%	4,000	6,491	7,214	11.1%
3rd Point	250	179	174	-2.5%	4,000	4,141	4,741	14.5%
5th EDC	250	102	89	-12.9%	4,000	190	142	-25.3%
5th Point (cascading)	250	188	165	-12.2%	4,000	647	490	-24.3%
5th Point (MSR)	250	119	79	-33.2%	4,000	4409	2,414	-45.2%
6th Point	250	118	104	-11.7%	4,000	515	404	-21.7%
7th Point	250	112	107	-3.9%	4,000	2,177	3,231	48.4%

Drain inlet mass fluxes remain below HEI guidelines, but the mass flux parameters for various heaters exceed the guidelines for the thermal extraction case. For most FWHs, however, the mass flux parameter decreases, or the increase is small (<15%). The FWH 7 inlet mass flux parameter increases by nearly 50% due to the change in density from the lower shell pressure. If the subject station does not show sufficient margin to allow for this increase, the additional flashing steam could increase wear rates at the drain inlet and future inspections should be mindful for changes.

F7.6   Operating Pressure and Temperature

Shell side operating pressure and tube side and shell side operating temperatures are compared for the baseline and 30% thermal extraction cases in Tables F7-7 through F7-9. The shell side operating temperature is the saturation temperature of steam at the operating shell side pressure.

Table F7-7: Shell Side Operating Pressures (psia)

FW Heater	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	5.4	3.6	-33.0%
1st Point	5.4	3.6	-33.0%
2nd Point	15.9	10.8	-32.0%
3rd Point	40.6	28.2	-30.6%
4th Point	89.5	64.5	-28.0%
5th EDC	186.1	137.1	-26.3%
5th Point	186.1	137.1	-26.3%
6th Point	287.1	212.7	-25.9%
7th Point	408.7	303.0	-25.9%

Table F7-8: Shell Side Operating Temperatures (°F)

FW Heater	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	165.6	149.0	-16.6°F
1st Point	165.6	149.0	-16.6°F
2nd Point	215.9	196.8	-19.1°F
3rd Point	268.1	246.7	-21.4°F
4th Point	319.9	297.4	-22.4°F
5th EDC	375.8	351.4	-24.4°F
5th Point	375.8	351.4	-24.4°F
6th Point	413.3	387.0	-26.3°F
7th Point	446.7	418.3	-28.4°F

Table F7-9: Tube Side Operating Temperatures (°F)

FW Heater	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	126.6	113.5	-13.1°F
1st Point	161.7	144.8	-16.9°F
2nd Point	212.8	192.6	-20.2°F
3rd Point	265.0	243.3	-21.7°F
4th Point	316.4	293.5	-22.9°F
5th EDC	332.2	306.8	-25.4°F
5th Point	370.2	345.9	-24.3°F

FW Heater	Baseline (0% Extraction)	30% Extraction	Δ (30%)
6th Point	409.7	383.7	-25.9°F
7th Point	441.5	413.8	-27.7°F

Operating temperatures and pressures decrease for all FWHs, so margins with design values will improve for the thermal extraction case.

F7.7   Drain Cooler Tube Vibration

Tube vibration in the 1st through 7th point heater drain coolers is evaluated by comparing the drain cooler volumetric flow rates.

Table F7-10: Drain Cooler Vibration

FW Heater No.	Drain Volumetric Flow (gpm)		
	Baseline (0% Extraction)	30% Extraction	Δ (30%)
1st EDC	1,671	1,518	-9.1%
2nd Point	1,240	1,172	-5.5%
3rd Point	842	814	-3.3%
4th Point	439	423	-3.6%
5th EDC	3,767	3,235	-14.1%
6th Point	2,434	2,100	-13.7%
7th Point	1,578	1,363	-13.6%

As shown in Table F7-10, the volumetric flow through all drain coolers is expected to decrease during operation with 30% thermal extraction, resulting in increased margin for tube vibration parameters. Therefore, tube vibration is not expected to be caused by operating with thermal extraction.

F8.0   RESULTS AND CONCLUSIONS

Tube and tube side nozzle velocities exceed the HEI guidelines for several of the FWHs, but changes from the baseline case are small or decrease, so it is not expected that FWH tube degradation or nozzle wear will be an issue due to thermal extraction. Steam inlet nozzle velocities for the thermal extraction case increase for all FWHs and exceed the HEI guideline for the 2nd, 3rd and 4th point heaters, so shell wear rates will likely increase. It should also be noted that changes to steam inlet velocity can affect the wear pattern of the shell, and future inspections should be mindful for changes. Drain outlet velocities decrease for the thermal extraction case, so HEI guidelines are not challenged, and wear rates may decrease.

The pressure loss across the pass partition plate is expected to increase in FWHs 1 through 4 and both external drain coolers. However, the expected increase in tube side pressure drop for the thermal extraction case is not expected to appreciably impact reliable operation of the heaters.

Drain inlet mass fluxes remain below HEI guidelines, but the mass flux parameters for various heaters exceed the guidelines for the thermal extraction case. For most FWHs, however, the mass flux parameter decreases, or the increase is small (<15%). The FWH 7 inlet mass flux parameter increases by nearly 50% due to the change in density from the lower shell pressure. If the subject station does not show sufficient margin to allow for this increase, the additional flashing steam could increase wear rates at the drain inlet and future inspections should be mindful for changes.

Operating temperatures and pressures decrease for all FWHs, so margins with design values will improve for the thermal extraction case. Volumetric flow through all drain coolers is also expected to decrease during operation with 30% thermal extraction, resulting in increased margin for tube vibration parameters. Therefore, tube vibration is not expected to be caused by operating with thermal extraction.

Attachment G - Extraction Steam Evaluation

Prepared: Gabriel Neimark

Reviewed: Nic Richards

G1.0   PURPOSE

The purpose of this evaluation is to examine expected changes to operating conditions and performance parameters in relation to the design of the Extraction Steam (ES) System. These changes are due to operation with 30% thermal energy extracted from the main steam.

G2.0   SYSTEM & COMPONENT DESCRIPTION

To maximize steam cycle efficiency, the ES System diverts steam taken from the turbine to the feedwater heaters. There are three stages of extraction from the High Pressure (HP) turbine, and four stages of extraction from each Low Pressure (LP) turbine. The Extraction Steam is used to heat the feedwater in seven separate feedwater heater stages.

There are three trains for the 1st through 4th point LP feedwater heaters, two trains for the 5th and 6th point LP feedwater heaters, and two trains for the 7th point HP feedwater heater.

G3.0   METHODOLOGY

G3.1   Methodology

G3.1.1 Extraction Steam Lines Pressure Drop

Pressure drop in the ES lines will be evaluated using simplified incompressible flow methodology based on the Crane Technical Paper [pp. 3-4, Ref. G6.3]. The following equation will be utilized to estimate the ES lines pressure drop:

$$\Delta P = 2.80 \times 10^{-7} \frac{KW^2 v}{d^4}$$

Eq. G3-1

where:

ΔP = Pressure Drop [psi]
K = Resistance Coefficient [ul]
W = Mass Flow Rate [lbm/hr]
v = Specific Volume [ft3/lbm]
d = Piping Inside Diameter [in]

The K value for each segment of the ES piping, the saturation pressures of each feedwater heater shell, and the total mass flow rate of the ES from the PEPSE evaluation in Attachment A will be used to compute the pressure drop for each available line.

G3.1.2 Operating Conditions

ES line pressures and temperatures from the PEPSE analysis in Attachment A are compared for the baseline and 30% thermal extraction scenarios. These comparisons are used to generalize the impacts on relevant valve and expansion joint service conditions.

G3.1.3 Extraction Steam Expansion Joint Liner Thickness

The required expansion joint liner thicknesses for the baseline and 30% extraction cases are calculated using the following methodology and compared. Based on Section 4.10.2 of the EJMA standard [Ref. G6.1], the minimum liner thickness for expansion joints between 12 to 24-inch diameters is 0.048-in and 0.060-in for diameters of 26 to 48-in. When the internal sleeve length exceeds 18-in, the standard liner thickness is to be multiplied by $(L/18)^{0.5}$ where L is the internal sleeve length in inches. When the flow velocity exceeds 100 ft/sec, the standard liner thickness is to be multiplied by $(V/100)^{0.5}$ where V is the liner velocity and is computed by (equation per page 3-2, [Ref. G6.3]):

$$V = 0.0509 \frac{Wv}{d^2}$$

Eq. G3-2

where:

V = Mean Velocity of Flow [ft/sec]
W = Mass Flow Rate [lb_m/hr]
v = Specific Volume [ft^3/lb_m]
d = Piping Inside Diameter [in]

Where extremely turbulent flow is generated within 10 pipe diameters upstream of the expansion joint by valves, tees, and elbows, the flow velocity used in calculating the liner thickness shall be determined by multiplying the actual flow velocity by four [Ref. G6.1]. Since the expansion joint assemblies have high Reynolds's numbers, the 'turbulent flow multiplier' is used.

When the fluid temperature exceeds 300°F, the thickness increase factor shall be equal to E_{sc}/E_{sh} where E_{sc} is the internal sleeve modulus of elasticity at 300°F and E_{sh} is the internal sleeve modulus of elasticity at the media temperature [Ref. G6.1]. The only extraction line that experiences temperatures above 300°F is FWH 4 and the change in modulus of elasticity due to temperature change at baseline to 30% thermal power extraction conditions is expected to be negligible. Therefore, the temperature increase factor is ignored.

G4.0   ASSUMPTIONS

G4.1   Pressure Drop – Pressure loss is computed based on incompressible flow equations. Per Crane [Ref. G6.3], if the calculated pressure drop is less than about 10% of the inlet pressure, reasonable accuracy will be obtained if specific volume is based on either upstream or downstream conditions. Similarly, for pressure drop between 10% and 40% of inlet pressure, specific volume based on the average upstream and downstream conditions can be used. For conservatism, the specific volume of steam/steam water mixture is based on the feedwater heater shell pressure and the turbine extraction point enthalpy. Using the end-point pressure to determine specific volume is conservative with respect to pressure drop and line velocity.

G4.2   Flow Rate – It is assumed that the flow rate is equal in all heater trains from the HP Turbine. The flow rate is used as input for the calculation of ES line pressure drop. While some flow variation

between trains may exist, it will affect the losses associated with piping to only a small degree. The piping loss is a very small part of the total line loss, which accounts for losses due to various components such as elbows and valves. Loss factors for these components are typically conservative in nature. Also note that the higher flow from either string from the PEPSE analysis (see Attachment A) is used. This should provide adequate allowance and margin for differences between heater strings.

G5.0   DESIGN INPUTS

G5.1   Operating Parameters

ES flows, temperatures, pressures, and enthalpies are taken from the PEPSE results given in Attachment A. For this analysis, the maximum values for mass flow, pressure, and enthalpy from the three strings for FWHs 1-4 are used. The pressure subscripts 'US' and 'DS' indicate upstream and downstream, respectively. Specific volume is based on downstream pressure, yielding a higher result which is conservative with respect to flow velocity. This is consistent with Assumption G4.1. Temperature is based on upstream pressure, yielding a higher temperature which is conservative with respect to maximum rated temperature for equipment. Both specific volume and temperature are calculated with the Excel STMFUNC add-in [Ref. G6.2].

Table G5-1: Heat Balance Data – 0% Extraction

Parameter	Mass Flow W (lb_m/hr)	Pressure P_{DS} (psia)	Pressure P_{US} (psia)	Enthalpy h (Btu/lb_m)	Spec. Vol υ_{DS} (ft^3/lb_m)	Temp. T_{US} (°F)
HP Turbine to 1st Stg. Rhtr	1.36E+05	448.7	451.0	1159.0	0.97	456.5
HP Turbine to 7th Stg. FWH	5.16E+05	408.7	451.0	1144.6	1.05	456.5
HP Turbine to 6th Stg. FWH	8.01E+05	287.1	296.5	1114.2	1.44	416.3
HP Turbine to 5th Stg. FWH	7.47E+05	186.1	190.3	1104.0	2.18	377.6
LP Turbine to 4th Stg. FWH	6.13E+05	89.6	92.4	1219.2	5.39	382.5
LP Turbine to 3rd Stg. FWH	5.96E+05	40.6	41.9	1158.8	10.2	270.1
LP Turbine to 2nd Stg. FWH	6.23E+05	15.9	16.4	976.3	20.4	217.7
LP Turbine to 1st Stg. FWH	6.63E+05	5.4	5.4	730.6	40.7	165.7

Table G5-2: Heat Balance Data – 30% Extraction

Parameter	Mass Flow W (lb$_m$/hr)	Pressure P$_{DS}$ (psig)	Pressure P$_{US}$ (psig)	Enthalpy h (Btu/lb$_m$)	Spec. Vol υ_{DS} (ft^3/lb$_m$)	Temp. T$_{US}$ (°F)
HP Turbine to 1st Stg. Rhtr	9.07E+04	335.3	337.0	1171.3	1.33	428.1
HP Turbine to 7th Stg. FWH	3.94E+05	303.0	337.0	1159.7	1.45	428.1
HP Turbine to 6th Stg. FWH	6.96E+05	212.7	219.7	1130.8	1.98	389.8
HP Turbine to 5th Stg. FWH	7.47E+05	137.1	140.2	1115.3	2.99	353.2
LP Turbine to 4th Stg. FWH	5.97E+05	64.6	66.6	1225.6	7.60	386.4
LP Turbine to 3rd Stg. FWH	5.82E+05	28.2	29.1	1162.4	14.5	248.6
LP Turbine to 2nd Stg. FWH	5.65E+05	10.8	11.2	1020.5	31.2	198.5
LP Turbine to 1st Stg. FWH	5.32E+05	3.6	3.6	800.9	67.2	149.1

G5.2   Expansion Joint Design Data

The input used to calculate the expansion joint required liner thickness is given below based on a typical plant configuration.

Table G5-3: Expansion Joint Design Data

Expansion Joint Location	Nom. Dia. [in.]	Liner ID [in.]	Liner Length [in.]
4th Point Heater	14	11.75	9.63
3rd Point Heater	18	15.75	9.75
2nd Point Heater	28	25.25	9.75
1st Point Heater	30	27.25	15.25

G5.3   Line Information

The extraction steam piping information used to calculate pressure drop for each line is given below based on a typical plant configuration.

Table G5-4: ES Line Information

	Piping Segment	Pipe ID (in)	Total K
HPT to 7th Stg FWH	Turb Extraction A	13.12	2.491
	Turb Extraction B	13.12	2.772
	Turb Extraction	18.81	3.945
	To Heater 7A	13.12	3.09
	To Heater 7B	13.12	3.342
HPT to 6th Stg FWH	Turb Extraction A	16.88	1.738
	Turb Extraction B	16.88	1.623
	Turb Extraction	22.62	4.204
	To Heater 6A	16.88	3.59
	To Heater 6B	16.88	3.814
HPT to 5th Stg FWH	Turb Extraction A	18.81	2.917
	Turb Extraction B	18.81	2.368
	Turb Extraction	29.00	4.043
	To Heater 5A	22.62	3.179
	To Heater 5B	22.62	3.63
LPT to 4th Stg FWH	Turb Extraction	13.00	2.467
	To Heater 4A	19.00	6.113
	Turb Extraction	13.00	2.467
	To Heater 4B	19.00	5.683
	Turb Extraction	13.00	2.467
	To Heater 4C	19.00	6.141
LPT to 3rd Stg FWH	Turb Extraction	17.00	3.047
	Turb Extraction	23.00	3.518
	To Heater 3A	17.00	2.317
	Turb Extraction	17.00	3.098
	Turb Extraction	23.00	3.45
	To Heater 3B	17.00	2.339
	Turb Extraction	17.00	3.098
	Turb Extraction	23.00	3.5
	To Heater 3C	17.00	2.339
LPT to 2nd Stg FWH	Turb Extraction	27.00	1.872
	Turb Extraction	39.00	3.001
	To Heater 2A	27.00	2.038
	Turb Extraction	27.00	1.872
	Turb Extraction	39.00	3.076
	To Heater 2B	27.00	2.038
	Turb Extraction	27.00	1.872

	Piping Segment	Pipe ID (in)	Total K
	Turb Extraction	39.00	3.072
	To Heater 2C	27.00	2.056
LPT to 1st Stg FWH	To Heater 1A	29.00	2.439
	To Heater 1A	29.00	2.116
	To Heater 1A	29.00	2.705
	To Heater 1A	29.00	2.345

G6.0   REFERENCES

G6.1   Standards of the Expansion Joint Manufacturers Association (EJMA), Inc., Ninth Edition, 2008.

G6.2   STMFUNC (Steam Table Function Dynamic Link Library) S&L Program Number 03.7.598 2.0, dated 06-11-2018.

G6.3   Crane Technical Paper No. 410, *Flow of Fluids Through Valves, Fittings, and Pipe*, Twenty Fifth Printing, 1991.

G6.4   Standards of the Expansion Joint Manufacturers Association (EJMA), Inc., Ninth Edition, 2008.

G7.0   EVALUATIONS

G7.1   Pressure Drop

ES line pressure drops are compared for the baseline and 30% thermal extraction scenarios in Table G7-1.

Table G7-1: ES Line Pressure Drop

	Upstream Pressure [psia]			Pressure Drop [psid]		
	0%	30%	Delta	0%	30%	Delta
HPT to 7th Stg FWH	451.0	337.0	-25.3%	6.50	5.24	-19.4%
HPT to 6th Stg FWH	296.5	219.7	-25.9%	8.46	8.82	4.2%
HPT to 5th Stg FWH	190.3	140.2	-26.3%	4.97	6.82	37.4%
LPT to 4th Stg FWH	92.39	66.6	-27.9%	4.33	5.80	33.9%
LPT to 3rd Stg FWH	41.9	29.11	-30.5%	3.24	4.41	35.8%
LPT to 2nd Stg FWH	16.43	11.18	-32.0%	0.78	0.98	25.9%
LPT to 1st Stg FWH	5.428	3.637	-33.0%	0.13	0.14	6.4%

The pressure drop in the lines from the HPT to 7th stage FWHs decreases, but all other extraction steam lines see an increase in pressure drop for the 30% thermal extraction case due to higher flow velocities. The most significant changes are in lines to the 2nd, 3rd, 4th, and 5th stage FWHs which have an increase in pressure drop of greater than 25%.

G7.2   Operating Conditions

ES line pressures and temperatures for the baseline and 30% thermal extraction scenarios are compared in Table G7-2.

Table G7-2: ES Line Operating Conditions

	Line Pressure [psia]			Line Temperature [°F]		
	0%	30%	Delta	0%	30%	Delta
HPT to 1st Stg Rhtr	448.7	335.3	-25.3%	456.50	428.15	-28.4°F
HPT to 7th Stg FWH	408.7	303.0	-25.9%	456.50	428.15	-28.4°F
HPT to 6th Stg FWH	287.1	212.7	-25.9%	416.29	389.77	-26.5°F
HPT to 5th Stg FWH	186.1	137.1	-26.3%	377.64	353.15	-24.5°F
LPT to 4th Stg FWH	89.6	64.6	-27.9%	382.52	386.44	3.9°F
LPT to 3rd Stg FWH	40.6	28.2	-30.5%	270.06	248.61	-21.4°F
LPT to 2nd Stg FWH	15.9	10.8	-32.0%	217.68	198.51	-19.2°F
LPT to 1st Stg FWH	5.4	3.6	-33.0%	165.73	149.10	-16.6°F

Pressures and temperatures decrease for the thermal extraction case in all lines other than a small temperature increase (<5°F) in the 4th Stg FWH line. Based on these results, margins for design pressures and temperatures will largely improve for relevant valves and expansion joints.

G7.3   Expansion Joint Required Liner Thickness

Required liner thicknesses for the baseline and 30% thermal extraction scenarios are compared in Table G7-3.

Table G7-3: Expansion Joint Required Liner Thickness

	Required Liner Thickness [in]		
	0%	30%	Delta
LPT to 4th Stg FWH	0.137	0.160	17.2%
LPT to 3rd Stg FWH	0.138	0.163	17.9%
LPT to 2nd Stg FWH	0.156	0.184	17.8%
LPT to 1st Stg FWH	0.149	0.172	15.1%

Liner thickness requirements increase for the thermal extraction case. Existing expansion joints will need to be evaluated on a plant-specific basis and may need to be replaced to ensure they meet these new requirements.

G8.0   RESULTS AND CONCLUSIONS

Analysis of the extraction steam system for the 30% thermal extraction scenario shows that overall, extraction steam line pressure drops increase due to higher flow velocities, with lines to the 2nd, 3rd, 4th, and 5th stage feedwater heaters seeing an increase of over 25%. Expansion joint liner thickness requirements also increase by up to ~18%, and existing expansion joints will need to be evaluated on a plant-specific basis and may need to be replaced to ensure they meet these new requirements.

Pressures and temperatures mostly decrease during operation with thermal extraction, so margins for design pressures and temperatures will largely improve for valves and expansion joints in the extraction steam system. The only exception is a slight temperature increase (<5°F) in the 4th Stage FWH extraction line. This slight increase is expected to be within the design margin of a typical plant.

Attachment H – Heater Drain System Assessment

Prepared: Nic Richards

Reviewed: Pawel Kut

H1.0   PURPOSE

The purpose of this appendix is to assess the heater drain system performance and expected changes to operating conditions due to operation with 30% turbine cycle thermal energy extracted from the main steam.

H2.0   SYSTEM & COMPONENT DESCRIPTION

H2.1   System Description

There are seven stages of feedwater heating for normal operations. Two parallel trains ('A' and 'B' trains), each consisting of a feedwater heater (FWH) 5, 6 and 7, are available for normal operation. Drains cascade back to the heater drain tank (HDT) starting at FWH 7. Flow for each train passes through the FWH 5 external drain coolers before entering the HDT. Emergency drains to the condenser are available for FWHs 5, 6, and 7.

Three parallel FWH drain trains ('A' train, 'B' train, and 'C' train), each consisting of a FWH 1, 2, 3, and 4, are available for normal operation. Drains cascade from FWH 4 to the flash tanks through FWHs 3 and 2. FWHs 1 drain to the flash tanks as well. Each flash tank drains to the condenser via the FWH 1 external drain coolers. Emergency drains to the condenser are available for FWHs 4, 3, and 2, as well as the flash tanks.

Four MSR drain trains ('A' train, 'B' train, 'C' train, and 'D' train), each consisting of a moisture separator drain tank (MSDT), 1st stage reheater drain tank (RH1DT), and a 2nd stage reheater drain tank (RH2DT), are available for normal operation as well. The MSDT drains are directed to the HDT. The 1st and 2nd stage reheater drains are directed to FWHs 5 and 7, respectively. Emergency drain lines to the condenser are available for each of the drain lines.

H2.2   Component Description

a) *Normal and Emergency Drain Control Valves*

The normal and emergency drain flow paths for each component are described below:

Table H2-1 – Component Flow Path Descriptions

Service	Source	Destination
7th Point Normal	FWH 7	FWH 6
7th Point Emergency	FWH 7	Condenser
6th Point Normal	FWH 6	FWH 5
6th Point Emergency	FWH 6	Condenser
5th Point Normal	FWH 5	DC 5
5th Point Emergency	FWH 5	Condenser
Drain Cooler 5 Normal	DC 5	HDT
Drain Cooler 5 Emergency	N/A	N/A
4th Point Normal	FWH 4	FWH 3
4th Point Emergency	FWH 4	Condenser

Service	Source	Destination
3rd Point Normal	FWH 3	FWH 2
3rd Point Emergency	FWH 3	Condenser
2nd Point Normal	FWH 2	Flash Tanks
2nd Point Emergency	FWH 2	Condenser
1st Point Normal	FWH 1	Flash Tanks
1st Point Emergency	N/A	N/A
Flash Tank Normal	Flash Tanks	DC 1
Flash Tank Emergency	Flash Tanks	Condenser
Drain Coolers 1 Normal	DC 1	Condenser
Drain Coolers 1 Emergency	N/A	N/A
HDT Normal	FWH Drain Tank	Condensate Booster System
HDT Emergency	FWH Drain Tank	Condenser
RH2DT Normal	2nd Stage Drain Tanks	FWH 7
RH2DT Emergency	2nd Stage Drain Tanks	Condenser
RH1DT Normal	1st Stage Drain Tanks	FWH 5
RH1DT Emergency	1st Stage Drain Tanks	Condenser
MSDT Normal	MSR Shell Drain Tanks	HDT
MSDT Emergency	MSR Shell Drain Tanks	Condenser

b) *Drain Tanks*

Drain tanks are provided to collect condensed steam from the moisture separators, 1st and 2nd stage reheaters, and feedwater heaters. The drain tanks in the HD system include:

i) Heater Drain Tank

ii) Moisture Separator Drain Tanks

iii) 1st Stage Reheater Drain Tanks

iv) 2nd Stage Reheater Drain Tanks

v) Flash Tanks

c) *Heater Drain Pumps*

The HDPs function to pump drains collected in the HDT forward to the condensate system through control valves. There are three 50% capacity HDPs. Normally two pumps operate with a third in standby. These pumps and control valves are evaluated in the Power Train Pumps Assessment (see Attachment D)

H3.0   METHODOLOGY

H3.1   Required Drain Control Valve (DCV) Capacity

The flow capacity (C_V) of a control valve is a function of the valve body, valve trim, valve stem position, fluid properties of inlet liquid, and downstream backpressure. The methodology for evaluating the capacity is the standard industry method as outlined in the Masoneilan Control Valve Sizing Handbook [Ref. H6.1]. For the evaluations here, the required duty (in lb_m/hr) is taken from the heat balances (see Design Input H5.1). The C_V required of the valve is then determined and the required valve flow coefficient during 30% thermal power extraction operating conditions is compared against the baseline valve C_V to determine the impact operating with thermal power extraction has on the level control valves.

The steps in the determination are as follows:

- Determine the required mass flow rate (see Design Input H5.1 for inputs used).

- Determine the valve inlet water temperature and pressure (see Design Input H5.1 for inputs used).

- Determine valve inlet pressure (see Section H3.1.2).

- Determine the pressure differential at which the valve chokes. This is termed the 'allowable pressure differential' as any further decrease in downstream pressure (increase in valve pressure differential) will not increase the mass flow rate through the valve. Required input for this includes the pressure recovery factor (F_L), the inlet pressure (P_1), the critical pressure ratio factor (F_F), and the saturation vapor pressure at the valve inlet (P_v).

- Determine the valve outlet pressure if no choking occurs (see Section H3.1.4) to determine valve pressure drop without choking (valve inlet pressure minus valve outlet pressure).

- Set the 'available pressure drop' across the valve equal to the smaller of the two pressure drops from above.

- Determine the required C_v based on the volumetric flow rate, the entering fluid specific gravity, and the available pressure drop.

- Compare the required C_v to the VWO C_v.

H3.1.1 Valve Inlet Pressure

The inlet pressure to the control valve is calculated based on the upstream heater shell side pressure. Elevation head between the operating level in the heater and the centerline elevation of the valve is then added/subtracted from this pressure. Next, the pressure drop through the drain cooler or upstream FWH is subtracted, if applicable. Pressure loss in the piping between the upstream heater and the valve is computed using Crane [Ref. H6.2]. These pressure differentials are based on generic plant input.

H3.1.2 Allowable Pressure Drop

The allowable pressure drop is based on the choked pressure drop of the valve and is defined as follows [Ref. H6.1]:

$$\Delta P_{ch} = F_L{}^2(P_1 - F_F P_V) \qquad\qquad \text{Eq. H3-1}$$

where:

ΔP_{ch} Pressure differential at which the flow chokes [psid]

F_L Pressure recovery factor (see Assumption H4.1)

P_1 Valve inlet pressure [psia]

F_F Critical pressure ratio factor (see Equation H3-3)

P_v Vapor pressure of water at inlet temperature [psia]

and

$$F_F = 0.96 - 0.28\sqrt{P_V/P_C} \qquad\qquad \text{Eq. H3-2}$$

where:

F_F Critical pressure ratio

P_V Valve inlet vapor pressure [psia]

P_C Critical pressure of water, 3206 psia [Ref. H6.1]

H3.1.3 Pressure Drop Based on Friction Flow in the Downstream Piping

In addition to the allowable pressure drop based on the valve characteristics, there is also an available pressure drop across the valve based on frictional pressure drop and elevation changes in the downstream piping. These pressure differentials are based on generic plant input. The resulting outlet pressure is then subtracted from the inlet pressure (see Section H3.1.2), giving an available pressure drop across the valve.

H3.1.4 Control Valve Liquid Flow Coefficient C_V

Control valve C_V is defined as [Ref. H6.1]:

$$C_V = \frac{q}{F_P}\sqrt{\frac{G_F}{\Delta P_a}} \qquad\qquad \text{Eq. H3-3}$$

where:

C_V Valve flow sizing coefficient

q Flow rate [gpm]

F_P Piping geometry factor

ΔP_a Allowable pressure drop across the valve [psid]

G_f Specific gravity of fluid

In the expression above, q and G_f are based on the entering fluid volumetric flow rate, pressure and temperature. The pressure drop is taken as the minimum of (i) the allowable pressure drop based on choked flow considerations and of (ii) the available pressure drop from frictional and elevation head pressure drop evaluations. Pipe fittings are accounted for in the generic pipe plant losses so the piping geometry factor is not used.

H3.2   Tank Parameters

Operating parameters of the system tanks are reviewed to evaluate the impact of operating with thermal power extraction.

H4.0   ASSUMPTIONS

H4.1   Valve Pressure Recovery Factor (F_L)

A generic pressure recovery factor of F_L = 0.85 is used based on typical industry values.

H5.0   DESIGN INPUTS

H5.1   FWH Drain Baseline and 30% Thermal Extraction Conditions

Drain flows, pressures, and temperatures are taken from Attachment A and averaged across the available strings. The average values for the baseline and 30% Thermal Extraction cases are presented in Table H5-1 below.

Table H5-1 – Average FWH Drain Conditions

Parameter	Units	Baseline (0% Thermal Extraction)	30% Thermal Extraction
MSDT Drain Flow	lbm/hr	331,167	192,757
MSDT Drain Pressure	psia	184.6	136.0
MSDT Drain Temperature	°F	375.1	350.8
RH1DT Drain Flow	lbm/hr	135,811	90,676
RH1DT Drain Pressure	psia	444.2	332.0
RH1DT Drain Temperature	°F	455.0	426.7
RH2DT Drain Flow	lbm/hr	200,488	192,645
RH2DT Drain Pressure	psia	864.2	866.1
RH2DT Drain Temperature	°F	527.2	527.4
FWH 3 LPT to Pressure	psia	40.6	28.2
FWH 4 LPT to Flow	lbm/hr	202,252	197,100
FWH 4 LPT to Pressure	psia	89.5	64.5
FWH 1 Extraction Pressure	psia	5.42	3.63
FWH 1 Drain Temp	°F	165.2	148.4
FWH 2 Extraction Pressure	psia	15.9	10.8
FWH 2 Drain Temp	°F	169.9	152.0
FWH 3 Extraction Pressure	psia	40.6	28.2

Parameter	Units	Baseline (0% Thermal Extraction)	30% Thermal Extraction
FWH 3 Drain Temp	°F	225.4	204.6
FWH 4 Extraction Pressure	psia	89.5	64.5
FWH 4 Drain Temp	°F	275.5	253.2
FWH 5 Extraction Pressure	psia	186.1	137.1
FWH 5 Drain Temp	°F	375.8	351.4
FWH 6 Extraction Pressure	psia	287.1	212.7
FWH 6 Drain Temp	°F	374.9	349.3
FWH 7 Extraction Pressure	psia	408.7	303.0
FWH 7 Drain Temp	°F	421.0	393.1
FWH 7 Drain Flow	lbm/hr	658,822	582,489
FWH 6 Drain Flow	lbm/hr	1,059,170	930,613
DC 5 Drain Flow	lbm/hr	1,704,062	1,485,669
FWH 4 Drain Flow	lbm/hr	202,252	197,100
FWH 3 Drain Flow	lbm/hr	398,540	389,159
FWH 2 Drain Flow	lbm/hr	601,704	572,709
DC 1 Drain Flow	lbm/hr	821,877	749,629
Condenser Shell Pressure	psia	1.42	1.10

H6.0   REFERENCES

H6.1   BHMN-Valve-Sizing-Handbook-TS-19540C-0222, "Masoneilan Control Valve Sizing Handbook," Baker Hughes, 02/2022

H6.2   Flow of Fluids Through Valve, Fittings, and Pipe, Crane Technical Paper No. 410, 1991

H6.3   STMFUNC, "Steam Table Function Dynamic Link Library," S&L Program Number 03.7.598-2.0

H7.0   EVALUATIONS

H7.1   Valve Flow Capacity

H7.1.1 Valve Flow

Valve volumetric flow is computed based on the mass flow rate and fluid temperature. The liquid density is computed using Excel add-on STMFUNC [Ref. H6.3]. Table H7-1 provides a comparison of the volumetric mass flow rates.

Table H7-1 – Drain Volumetric Flow Comparison

Description	Baseline (0% Extraction) [gpm]	30% Extraction [gpm]	Percent Change [-]
Flash Tank Normal	1,683	1,527	-9.3%
FWH 2 Normal	1,234	1,168	-5.4%
FWH 3 Normal	836	809	-3.2%
FWH 4 Normal	434	419	-3.6%
FWH 6 Normal	2,416	2,086	-13.7%
FWH 7 Normal	1,557	1,346	-13.5%
MSDT Normal	756	433	-42.8%
RHDT1 Normal	331	215	-34.9%
RHDT2 Normal	527	507	-3.9%
Flash Tank Emergency	1,683	1,527	-9.3%
FWH 2 Emergency	1,234	1,168	-5.4%
FWH 3 Emergency	836	809	-3.2%
FWH 4 Emergency	434	419	-3.6%
FWH 5 Emergency	3,890	3,335	-14.3%
FWH 6 Emergency	2,416	2,086	-13.7%
FWH 7 Emergency	1,557	1,346	-13.5%
MSDT Emergency	756	433	-42.8%
RHDT1 Emergency	331	215	-34.9%
RHDT2 Emergency	527	507	-3.9%

As shown in Table H7-1, drain flows decrease between 3% and ~40% when 30% thermal power is extracted.

H7.1.2 Valve Pressure Drop

The pressure drop across the valve is the minimum of the allowable pressure drop due to choked flow (see Section H3.1.2) and the available pressure drop from valve inlet to outlet based on flow conditions and frictional losses (see Section H3.1.3). Table H7-2 provides the computed pressure losses. The minimum pressure loss for each valve is shown in bold text.

Table H7-2 – Drain Valve Pressure Loss

Description	Baseline (0% Extraction)		30% Extraction		Percent Change	
	Choked dP [psid]	Available dP [psid]	Choked dP [psid]	Available dP [psid]	Choked dP [-]	Available dP [-]
Flash Tank Normal	**2.7**	7.3	**2.9**	6.2	8.0%	-14.6%
FWH 2 Normal	**2.3**	3.2	**0.5**	0.5	-77.6%	-83.4%
FWH 3 Normal	**9.1**	14.6	**4.7**	7.6	-48.7%	-48.0%
FWH 4 Normal	**32.1**	44.5	**23.5**	32.2	-26.5%	-27.6%
FWH 6 Normal	**85.0**	95.9	**63.3**	70.8	-25.5%	-26.2%
FWH 7 Normal	**90.9**	108.1	**65.3**	76.9	-28.1%	-28.8%
MSDT Normal	19.6	**5.9**	15.1	**6.5**	-23.0%	11.0%
RHDT1 Normal	**42.7**	249.3	**28.1**	187.3	-34.0%	-24.9%
RHDT2 Normal	**115.6**	454.6	**116.0**	562.4	0.4%	23.7%
Flash Tank Emergency	**4.1**	9.2	**4.1**	7.8	-0.7%	-15.1%
FWH 2 Emergency	**5.5**	11.7	**3.7**	7.6	-32.5%	-35.0%
FWH 3 Emergency	**15.0**	37.1	**10.6**	25.4	-29.1%	-31.4%
FWH 4 Emergency	**38.4**	92.0	**30.0**	67.8	-21.9%	-26.3%
FWH 5 Emergency	**23.0**	196.4	**18.5**	148.1	-19.4%	-24.6%
FWH 6 Emergency	**86.9**	283.3	**65.3**	209.6	-24.9%	-26.0%
FWH 7 Emergency	**97.5**	405.9	**72.0**	300.9	-26.1%	-25.9%
MSDT Emergency	**16.4**	186.0	**11.8**	137.9	-28.2%	-25.9%
RHDT1 Emergency	**47.6**	444.7	**32.9**	333.2	-30.9%	-25.1%
RHDT2 Emergency	**116.8**	862.6	**117.3**	865.2	0.4%	0.3%

As shown in Table H7-2, all drain control valves experience choked flow conditions except the moisture separator drain tank. With respect to valve capacity, a decrease in valve pressure loss is non-conservative, as the pressure loss is in the denominator (see Equation H3-3). Therefore, nearly all valves see a non-conservative reduction in allowable pressure loss, with the exception of the 2nd stage reheater drain tank. In most cases, the reduction in allowable pressure drop is significant, with FWH 2 normal drains seeing greater than 80% reduction in available dP. The resulting impact on required C_V is discussed in Section H7.3.

H7.1.3 Required Valve C_V

The resulting required valve C_V values are presented in Table H7-3.

Table H7-3 – Drain Valve Required C_V Capacity

Description	Baseline (0% Extraction) [-]	30% Extraction [-]	Percent Change [-]
Flash Tank Normal	1019	892	-12.5%
FWH 2 Normal	796	1595	**100.5%**

Description	Baseline (0% Extraction) [-]	30% Extraction [-]	Percent Change [-]
FWH 3 Normal	271	367	**35.8%**
FWH 4 Normal	74	84	**13.1%**
FWH 6 Normal	245	248	**0.9%**
FWH 7 Normal	150	155	**3.2%**
MSDT Normal	292	160	-45.2%
RHDT1 Normal	46	37	-18.8%
RHDT2 Normal	43	41	-4.1%
Flash Tank Emergency	823	751	-8.7%
FWH 2 Emergency	520	600	**15.5%**
FWH 3 Emergency	211	243	**15.4%**
FWH 4 Emergency	68	74	**9.7%**
FWH 5 Emergency	759	731	-3.7%
FWH 6 Emergency	243	244	**0.5%**
FWH 7 Emergency	145	147	**1.7%**
MSDT Emergency	175	119	-31.9%
RHDT1 Emergency	43	34	-20.7%
RHDT2 Emergency	43	41	-4.1%

As shown in Table H7-3, the required C_V capacity for all FWHs increases with 30% thermal power extraction. Flash tank and the various MSR drain tanks all see reduced capacity requirements. FWHs 4, 6, and 7 exhibit required increases of less than 15%, which is typically within the operating margin of a well sized drain control valve. Therefore, no equipment changes would be expected, but a station specific review is required. FWHs 2 and 3, on the other hand, show significant increase in required flow capacity, with FWH 2 requiring approximately double the baseline capacity. Therefore, it is expected that a station specific review of these FWHs would result in requiring valve replacement prior to operation with thermal power extracted.

H7.2   Drain Tank Parameters

The operating parameters for the drain tanks (MSDT, RH1DT, RH2DT, & Flash Tank) are reviewed in Table H7-4.

Table H7-4 – Drain Tank Conditions

Parameter	Units	Baseline (0% Extraction)	30% Extraction	Change
MSDT Drain Flow	lbm/hr	331,167	192,757	-41.8%
RH1DT Drain Flow	lbm/hr	135,811	90,676	-33.2%
RH2DT Drain Flow	lbm/hr	200,488	192,645	-3.9%
Flash Tank Drain Flow	lbm/hr	821,877	749,629	-8.8%
MSDT Drain Pressure	psia	184.6	136.0	-26.3%

Parameter	Units	Baseline (0% Extraction)	30% Extraction	Change
RH1DT Drain Pressure	*psia*	444.2	332.0	-25.3%
RH2DT Drain Pressure	*psia*	864.2	866.1	0.2%
Flash Tank Drain Pressure	*psia*	5.42	3.63	-33.0%
MSDT Drain Temperature	*°F*	375.1	350.8	-24.3°F
RH1DT Drain Temperature	*°F*	455.0	426.7	-28.3°F
RH2DT Drain Temperature	*°F*	527.2	527.4	0.3°F
Flash Tank Drain Temperature	*°F*	165.2	148.4	-16.8°F

As shown in Table H7-4, mass flow rates decrease for all drain tanks. Pressure and temperatures also increase for all tanks except the 2nd stage reheater drain tank. Conditions for RH2DT show minimal change. As all parameters either decrease or show minimal change, the heater drain system drain tanks are expected to operate normally during thermal power extraction operation.

H8.0   RESULTS AND CONCLUSIONS

The required C_V capacity for all the flash tank and the various MSR drain tanks DCVs show reduced capacity requirements when operating with thermal power extraction. DCVs for all FWHs will require greater flow passing capability. FWHs 4, 6, and 7 exhibit required increases of less than 15%, which is typically within the operating margin of a well sized drain control valve. Therefore, no equipment changes would be expected, but a station specific review is required. FWHs 2 and 3, on the other hand, show significant increase in required flow capacity, with FWH 2 requiring approximately double the baseline capacity. Therefore, it is expected that a station specific review of these FWHs would result in requiring valve replacement prior to operation with thermal power extracted for FWHs 2 and 3.

Operating parameters for all heater drain system drain tanks either decrease or show minimal change and are expected to operate normally during thermal power extraction operation.