Nebraska Public Power District
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USING PEPSE TO EVALUATE A HIGH PRESSURE TURBINE RETROFIT OPTIONS

Jay Favinger
John Cizek
Brett Reinboth
Nebraska Public Power District

Abstract

This paper describes how Nebraska Public Power District used PEPSE to evaluate options for replacing a high pressure turbine on a General Electric G3 turbine. PEPSE was used to develop a heat balance from plant process data for prospective bidders. After the bidding process, PEPSE was also used in the evaluation process.

Introduction

Gerald Gentleman Station (GGS) is Nebraska Public Power District's (NPPD) largest generating station. The station consists of two nominal 650 MW coal-fired units. GGS consistently provides more than fifty percent of NPPD's generation at one of the lowest costs in the nation.

The original Unit 2 turbine was a General Electric G3 turbine / generator set that began commercial operation January 1, 1982. The Unit 2 turbine had consistently experienced problems with solid particle erosion in the first stage nozzle block and deposits in the high pressure (HP) turbine. The full effect of the deposits was not realized until after 1994 when the first stage nozzle block was coated to reduce solid particle erosion. In the first six weeks of operation after the coating, the high pressure turbine efficiency and generation was observed to decrease significantly. Analysis of enthalpy drop tests indicated that a restriction had developed in the high pressure turbine between the nozzle block and the exhaust of the HP section. During the next outage, a borescope inspection confirmed the presence of fairly heavy deposits on the latter stages of the high pressure turbine and did not show signs of mechanical damage to the second and third stage diaphragms. Samples of the deposits were taken from the last stage buckets of the high pressure turbine. Analysis of the samples showed that most of the deposits were copper based. The copper alloy tubing in the feedwater and condensate systems was the source of the copper. The Unit 2 turbine performance would annually degrade 40 to 60 MW as shown in Attachment 1. This large capacity loss was able to be recovered on an annual basis by chemical foam cleaning or grit blasting the high pressure turbine section each spring prior to the summer peak load period. By 2005, all the copper alloy tubing in the condensate and feedwater systems had been replaced with stainless steel. While replacing the tubing slowed the rate of deposition, the hideout copper in the boiler superheater sections and steam piping was still causing performance degradations. This degradation due to the hideout copper was expected to continue for a number of years based on EPRI (Electric Power Research Institute) studies of the problem at other plants.

Since the early nineties, turbine vendors had been approaching GGS about retrofitting the Unit 2 high pressure turbine. The newer turbine designs offer a considerable improvement in section efficiency, provide additional output at the same steam conditions, and are less susceptible to solid particle erosion and deposits. They achieve the improved efficiency and capacity by utilizing computational fluid dynamics to optimize rotating and stationary blade profiles, as well as packing more stages into the high pressure turbine section. GGS was interested in replacing the Unit 2 high pressure turbine since first learning of the new designs, but NPPD has limited funds for capital improvements, and there were other improvements that were a higher priority. By the summer of 2005, funding became available for replacing the Unit 2 high pressure turbine in the spring of 2007.

Developing the PEPSE Model

Recognizing the benefits of competition, NPPD allowed potential vendors to take measurements and data necessary to engineer a retrofit turbine during previous outages when the high pressure turbine was open. They had also been provided with the original GE heat balance and some operating history. NPPD also recognized that the vendors needed a more accurate current operating heat balance at rated throttle steam conditions of 2400 psig, 1000º F, and valves wide open in order to receive proposals that could be easily evaluated. Operating history at GGS and comments from industry experts indicated that the flows used in the original GE heat balances were quite conservative. PEPSE was used to develop this current operating heat balance from data obtained with plant instrumentation.

GGS has used PEPSE for quite a number of years on various projects. A PEPSE model was made from the original Unit 2 GE heat balance as part of the PEPSE training project. The actual Unit 2 turbine cycle with two low pressure turbines, dual feedwater heater strings, dual shell condenser, attemperator spray flows, and steam coil air heater extraction steam is more complicated than both the original GE and PEPSE heat balances. Over time, the original PEPSE model had been modified to more closely resemble the actual plant. It was recognized that the vendors needed a simple heat balance similar to the original to bid on the project. Since PEPSE had evolved from a mainframe program when the original model was developed to the current Windows interface, the current PEPSE model was modified to more resemble the original heat balance. The modified model consisted of one low pressure turbine, a single feedwater heater string, one main condenser, and one boiler feedwater pump / turbine. The attemperator spray flows were included in the modified model since superheater spray flow makes up fifteen to twenty percent of Unit 2's throttle steam flow, and a considerable amount of reheat spray flow was required to control reheat steam temperature due to heat transfer conditions in the boiler. This modified Unit 2 PEPSE model is shown in Attachment 2.

The modified PEPSE model used the GE calculation methods for the turbine calculations along with performance mode feedwater heaters and full design mode condensers. The condensers were modeled in design mode, enabling the use of controls to adjust the heat transfer multipliers to match measured exhaust pressures for the turbine and boiler feedwater pump turbine. Special Option Number 2 was used to swing the expansion lines for the condensing turbine sections to achieve measured generation.

After the model was modified, PEPSE's graphics presentation capability was used to make a heat balance diagram. The format of the heat balance diagram was developed by taking the best features from vendor heat balances and coordinating them with the PEPSE graphics.

Determining the Data for the Heat Balance

After the heat balance was developed, it was time to provide valid actual operating data for the vendors. The best way to have done this would have been to test the turbine with test quality instrumentation on the high pressure turbine, feedwater flow, and superheat sprays. Unit 2’s performance degradation history dictated that this testing would have to be done within the first couple weeks after the high pressure turbine was overhauled or foam cleaned. Unfortunately, by the time the project got under way, that window of opportunity had past. Waiting for the next testing window would have delayed the project from 2007 to 2009.

GGS uses a steady load testing program to monitor turbine performance on a biweekly basis. The steady load tests are run at rated steam conditions with the control valves wide open using data from plant instrumentation. The use of plant instrumentation allows the Operations Department to perform the test at the convenience of NPPD’s Energy Control Center. Since the window of opportunity for testing a clean high pressure turbine had past, historical data from the steady load test program would have to be used for the heat balance. Due to Unit 2’s past copper deposit history, only data from the first test following a high pressure turbine cleaning would be used. Five tests from 2001 to 2005 were selected to be evaluated. After analyzing the data and removing the obviously bad data, the five tests were averaged for entering into the modified PEPSE model.

After the data was entered and run in the model, a thorough evaluation was performed. The PEPSE Mollier Diagram feature was used to compare the test data and the original heat balance expansion lines. Data that appeared not valid was deleted and PEPSE calculated a substitute value. The extraction flow to the boiler feedwater pump turbines was modeled using both measured flow and by having PEPSE calculate the flow. The measured flow was selected to be used for the final heat balance.

Ensuring that the throttle steam flow was as accurate as possible was a major concern. If it was too low, the new turbine could meet or exceed the efficiency guarantee, but the unit would not produce the expected capacity increase. If throttle steam flow utilized was higher than actual, this could result in an increased heat input to the boiler and trigger the new source review procedures. Several different methods of calculating throttle steam flow were modeled. The selected throttle steam flow was calculated by PEPSE from the measured feedwater flow using PEPSE's Stream Flow Option.

A copy of the final Actual Current Operating Performance (ACOP) heat balance provided to the vendors is shown in Attachment 3. The heat balance was not corrected to standard conditions since the vendors did not require it. Due to NPPD's concerns about new source review, the cycle heat input was included on the heat balance. The vendors were directed to base their proposals on the ACOP heat balance and were allowed to "adjust" the main steam flow to compensate for the anticipated reheat spray flow as long as they did not exceed the cycle heat input shown on the heat balance.

Evaluating the Proposals

Proposals were received from three vendors. All three vendors submitted a proposal for both partial arc and full arc admission turbines. The heat balances submitted were verified using PEPSE. For the verification process, the intermediate and low pressure turbine sections were converted to general (Type 8) turbines. The controls for adjusting the condenser heat transfer multipliers, Special Option 2, and Stream Flow Option were disabled for the verification.

One vendor used the 1997 ASME Steam Tables instead of the 1967 ASME Steam Tables that were used for the ACOP heat balance. Their heat balances were first modeled in PEPSE using the 1997 Steam Tables. The results from the 1997 steam table runs were then converted to 1967 steam tables to ensure that the vendors were evaluated fairly. The conversion to the 1967 steam tables lowered the vendor's proposed high pressure turbine efficiency by 0.6%.

The PEPSE results did not match any of the proposed heat balances exactly, but were close enough to ensure that all the vendor proposals were reasonable. There were steps that could have been taken with PEPSE to attempt to match the vendor heat balances exactly, but they were not deemed necessary. During the evaluation, minor mistakes were found with all the proposed heat balances, none of which were serious enough to eliminate any of the proposals.

The vendors had been requested to propose both partial arc and full arc admission turbines in order to allow NPPD to evaluate and select the option determined to be best for our system. Full arc admission turbines can be more efficient under full load conditions, but do not respond as well in load frequency control. While GGS Unit 2 is primarily a base loaded unit, it is sometimes requested to operate in load frequency control when required by system conditions. NPPD's Energy Control Center preferred to maintain as much load following flexibility in the GGS units as possible due to the unknowns of what sources will be providing future generation to the system. Some potential sources do not have much load following capability at all and the need for GGS to provide this capability may increase in the future. The difference in cycle heat rate between full arc and partial arc admission turned out to be only 6 to 16 BTU/kwh, which is less than expected. The District decided that the slight increase in efficiency was not worth the loss of the load following flexibility, and decided to purchase a partial arc admission turbine.

The proposals were also evaluated on retrofit experience, ability to meet schedule, technical and commercial exceptions, safety, and evaluated cost including life cycle cost advantages. After all the evaluation factors were analyzed, the project was awarded to ALSTOM.

Installation and Testing

The new high pressure turbine was delivered to GGS in April 2007. Unit 2 was shut down for a scheduled thirty-eight (38)-day outage the evening of April 27, 2007. The District and ALSTOM had developed a detailed retrofit schedule during the months leading into the outage. The District supplied the craft labor for both the removal of the old turbine and installation of the new one. ALSTOM supplied the technical guidance for the installation. Third-party contractors were hired for the in-house machining work and the laser alignment. The installation went well and the turbine work was completed ahead of schedule. Unit 2 was returned to service on June 4, 2007. There were very few problems with the turbine during startup. It was synchronized to the grid on the initial roll-to-speed. Following some extended holds for water chemistry issues, the unit reached rated conditions on June 8, 2007.

The retrofit contract contained performance guarantees for high pressure turbine section efficiency and steam swallowing capacity. Since the original stop and control valves were not replaced and losses in this area were not within the contractor's control, the high pressure turbine bowl conditions were used for the inlet conditions for the efficiency calculations. This required the addition of some new pressure taps on the steam leads between the valves and the turbine during the outage. Performance Consulting Services (PCS) was contracted to perform the guarantee testing. Following PCS' recommendation, True North Consulting was contracted to perform the flow measurements for the swallowing capacity testing. True North Consulting works with Advanced Measurement and Analysis Group (AMAG) to measure flow with cross-correlation ultrasonic flow meters. The cross-correlation ultrasonic flow meters provide accuracies close to a calibrated ASME PTC-6 flow section. This method was selected since an accurate flow measurement could be achieved without sending the existing feedwater flow nozzle for calibration or purchasing additional flow measuring elements. The cross-correlation ultrasonic flow meters did not require any modification to system piping.

Due to concerns of deposits forming on the high pressure turbine during startup, PCS monitored the turbine continuously from startup to after the guarantee testing was completed. An efficiency check was performed at low load with the unit in full arc admission mode. After the unit was transferred to partial arc admission mode, periodic efficiency checks were performed with all four control valves wide open during each step of the reduced pressure chemistry holds.

After the unit reached rated conditions, a total of three tests was performed. The unit was not fully isolated as required for the swallowing test during the first test period due to water chemistry concerns. The high pressure turbine exceeded the contract guarantee efficiency for all three tests. The turbine swallowing capacity guarantee was met during both tests two and three. The increase in output capacity of the turbine was close to the expected value. The reheat spray flows during the tests were slightly higher than predicted in the ALSTOM heat balance. The reheat spray flow during the second test was higher than expected since not enough time was allotted to clean the front of the boiler between tests one and two and hotter flue gas was entering the reheater area of the boiler. The key results of the tests are in the table below.

TEST RESULTS VERSUS HEAT BALANCE AND REPLACED HP TURBINE					
	ACOP Heat Balance	**ALSTOM Heat Balance**	**Test 1**	**Test 2**	**Test 3**
HP Turbine Efficiency (%)	81.9	92.7	93.28	93.23	93.15
Swallowing Capacity (klb/hr)	4462	4467		4476	4487
Generation (MW)	689	706	703	713	706
Reheat Spray Flow (klb/hr)	112	25	77	158	76

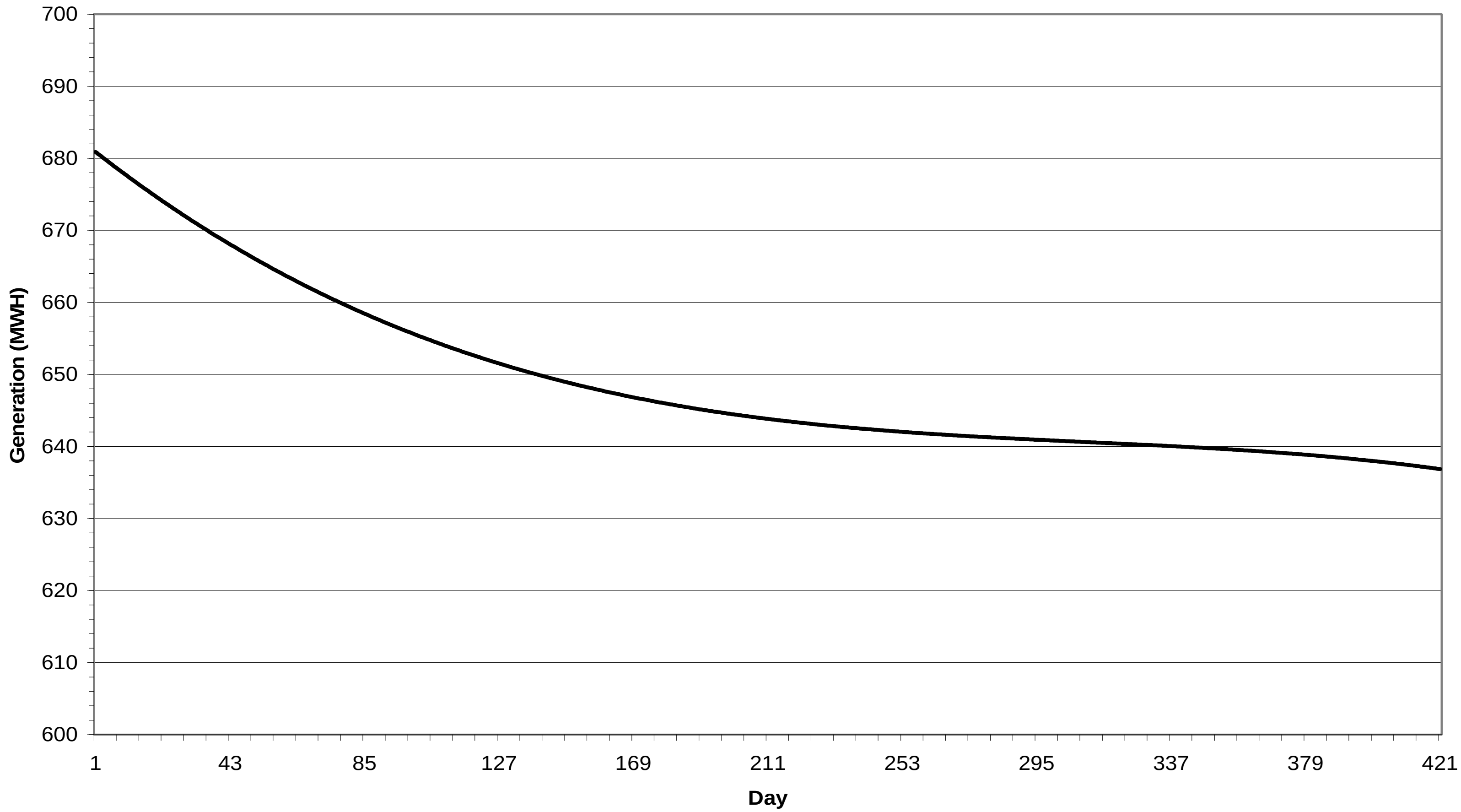
Conclusions

While the new high pressure turbine for Unit 2 has been in service for only a short time as this paper is being written, the initial results have been positive. The new turbine has increased capacity and improved efficiency without increasing the heat input to the unit. More operating time is required to see how deposits and solid particle erosion affect the turbine’s performance. The station will continue to use the steady load testing program and PEPSE to monitor the turbine’s performance and record any degradation.

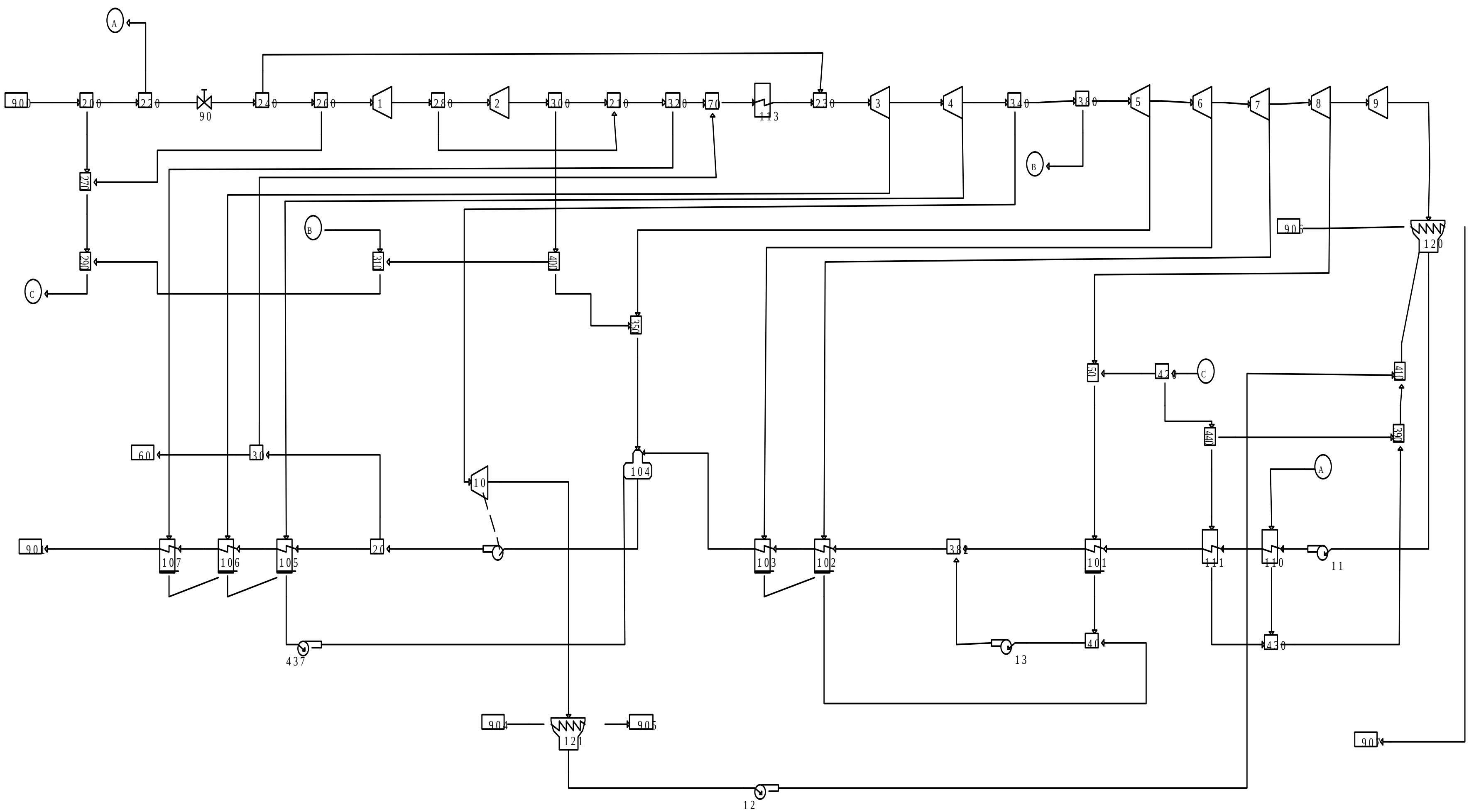
The GGS Unit 2 high pressure turbine retrofit project was a team effort. PEPSE proved to be a valuable tool for the team. PEPSE’s calculation and heat balance capabilities allowed the District to produce a reasonably accurate heat balance in a short period of time from process data. The use of actual test data is still preferred, but when evaluated properly, process data can be a suitable substitute. Maintaining the PEPSE models has proven to be a valuable asset in GGS’s continuing search to improve efficiency and maintain low cost.

ATTACHMENT 1

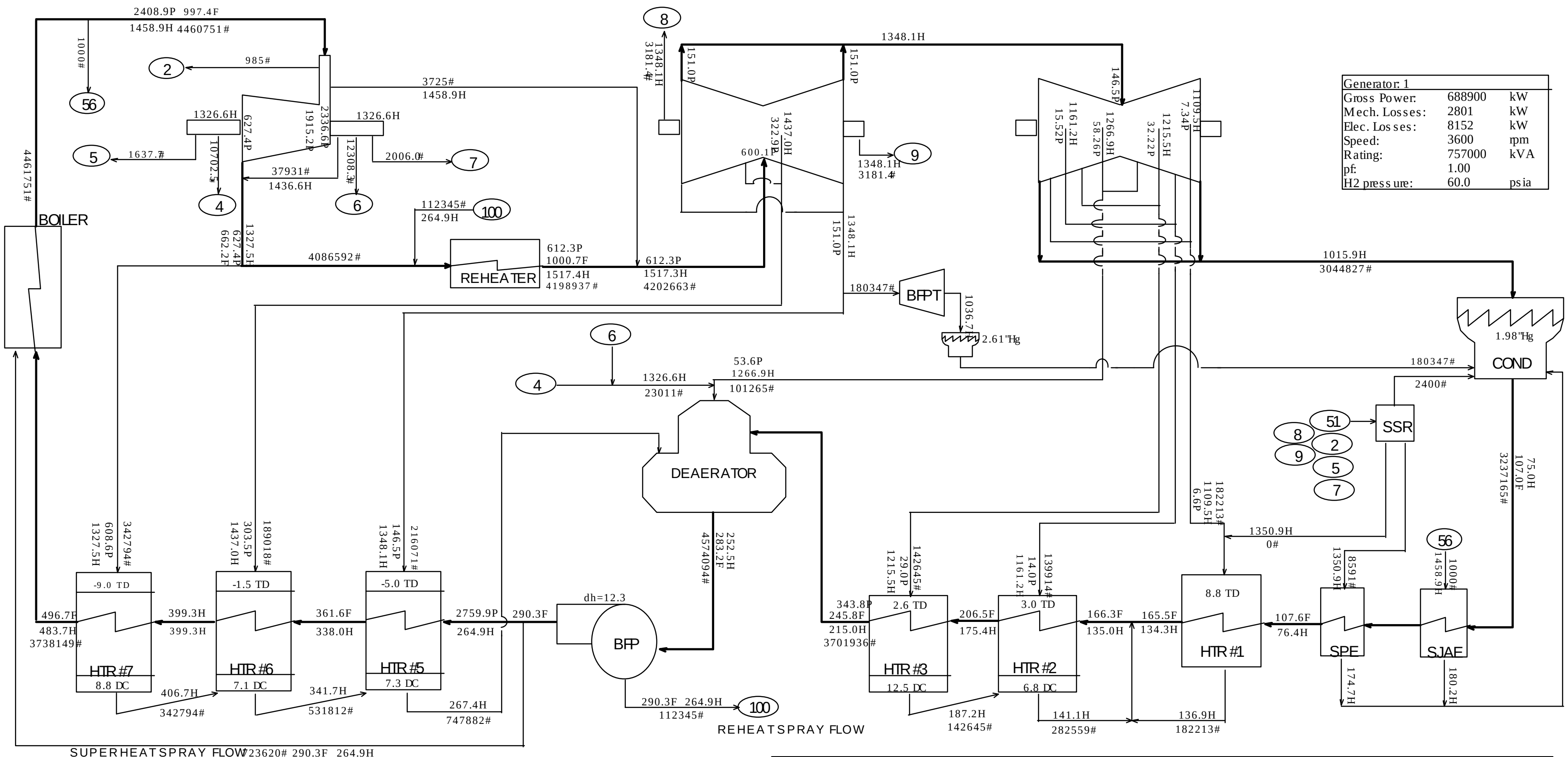
GGS UNIT 2 TYPICAL GENERATION DEGRADATION



ATTACHMENT 2
GGS UNIT 2 MODIFIED PEPSE TURBINE MODEL



ATTACHMENT 3
ACTUAL CURRENT OPERATING PERFORMANCE (ACOP) HEAT BALANCE



Input Flows For The Model

Feedwater Flow	3738149#
Superheat Spray Flow	723620#
Reheat Spray Flow	112345#
BFPT Extraction Steam Flow	180347#

The high pressure turbine bowl pressure is calculated in the model per the GE procedures.

NEBRASKA PUBLIC POWER DISTRICT
GERALD GENTLEMAN STATION UNIT 2

ACTUAL CURRENT OPERATING PERFORMANCE

Date Prepared	06/26/07
Gross Generation	688.9 MW
Cycle Heat Rate	7875.9 BTU/KWH
Cycle Heat Input	5425.708 MMBTU/HR

NPPD Heat Balance 1 Revision 2

P - Pressure, psia
T - Temperature, F
H - Enthalpy, BTU/lbm
- Flow Rate, Lbm/hr
"Hg - Pressure, In Hga
TD - Terminal Temperature Difference, F
DC - Drain Cooler Approach, F

References

PEPSE COMPUTER CODE Version 69/GT, SCIENTECH, LLC, 200 S. Woodruff, Idaho Falls, ID 83401

"Ultrasonic Flow Measurement at Nuclear Power Plants" by Ray Foster, Flow Control Network.com, 2005 Grand View Media Group, Inc.

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