Rhodhiss Hydropower Facility

Final Assessment Report

Revision 2.0, 04/13/2012

Prepared by
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831-6283
managed by
UT-BATTELLE, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

and

MESA ASSOCIATES, INC.
Chattanooga, TN 37402

and

HYDRO PERFORMANCE PROCESSES INC.
Doylestown, PA 18901

Contents

ACRONYMS AND ABBREVIATIONS **5**

EXECUTIVE SUMMARY **6**

1.0 Introduction **8**

1.1 Objective and Scope of Assessment 8

1.2 Plant General Information 8

1.3 Site Visit and Acknowledgment 10

2.0 Condition Assessment **11**

2.1 Civil/Structural Components 11

2.1.1 Observations and descriptions 11

2.1.2 Condition assessment results 13

2.2 Mechanical Components 14

2.2.1 Observations and descriptions 14

2.2.2 Condition assessment results 19

2.3 Electrical Components 21

2.3.1 Observations and descriptions 22

2.3.2 Condition assessment results 26

2.4 Instruments and Controls System 28

2.4.1 Observations and descriptions 28

2.4.2 Condition assessment results 30

2.5 Plant and Units Condition Assessment 30

3.0 Environmental Issues and Constraints **33**

4.0 Electric Power System Interconnection and Context **34**

4.1 Background on DEC 34

4.2 DEC Load 36

4.3 DEC Transmission Infrastructure and Constraints 38

5.0 Performance Assessment **40**

5.1 Hydrology-Based Performance Analyses 40

5.1.1 Site hydrological characteristics 40

5.1.2 Long-Term Stream Power (LTSP) analysis 40

5.1.3 Long-Term Production Potential (LTPP) analysis 41

5.1.4 Average Power Production (APP) calculation 43

5.1.5 Results from hydrology-based performance analyses 44
5.2 Optimization-Based Performance Analyses 49
5.2.1 Unit and plant performance curves 49
5.2.2 Operation efficiency analyses 57
5.2.3 Scheduling analyses 60
5.2.4 Avoidable loss analyses 63
5.2.5 Correlation analyses 63
5.2.6 Results from optimization-based performance analyses 63
6.0 Economic Valuation and Cost Estimate for Upgrades 64
6.1 Plant Owner Fleet Characteristics 64
6.2 Market Context 66
6.2.1 Energy prices/tariffs 66
6.2.2 Ancillary service prices/tariffs 67
6.2.3 Applicable incentives/legislation regarding renewable energy 69
6.3 Economic Valuation 70
6.3.1 Energy benefit ($/MWh) 70
6.3.2 Capacity and other benefit ($/kW-year) 72
6.4 Cost Estimates 73
6.4.1 Runner replacement of Units 1 and 3 73
6.4.2 Unit 3 exciting system upgrade 74
6.4.3 Unit 3 control system upgrade 74
6.5 Economic Feasibility and Financing Options 74
7.0 Conclusion and Recommendations 75
7.1 Summary of Condition and Performance Assessment Results 75
7.2 Environmental and Other Constraints Affecting Performance 75
7.3 Prioritized Opportunities for Production and Reliability Improvement 76
7.4 Recommendations for Additional Studies 77
8.0 References and Data Sources 78

Appendix 1: Combined Workbooks for Condition Ratings
Appendix 2: Workbooks for Performance Analyses

ACRONYMS AND ABBREVIATIONS

BP	Best Practices
cfs	cubic feet per second
CPL	Current Performance Level
DO	Dissolved Oxygen
DGA	Dissolved Gas Analysis
DOE	Department of Energy
EL	Elevation
ft	feet
GE	General Electric
HAP	Hydropower Advancement Project
I&C	Instrumentation and Controls
IPL	Installed Performance Level
kvA	kilovolt ampere
kW	kilowatt
MVA	megavolt ampere
MW	megawatt
MWhr	megawatt-hour
OEM	Original Equipment Manufacturer
ORNL	Oak Ridge National Laboratory
pcf	pounds per cubic foot
pf	power factor
PPL	Potential Performance Level
RPM	revolutions per minute
CI	Condition Indicator
DEC	Duke Energy Carolina
IPL	Installed Performance Level
CPL	Current Performance Level
PPL	Potential Performance Level
LMP	Locational marginal Price

EXECUTIVE SUMMARY

This condition and performance assessment report presents results of the second in a series of evolving standard assessments in the development of the Hydropower Advancement Project (HAP) standard assessment methodology. The priority objective for this report is to document the condition and performance of the facility and its components and identify the improvements that should be examined in subsequent cost-benefit estimation and prioritization activities. The report includes approximate cost estimates with AACEI Class 5 (concept screening) characteristics of project definition, end usage, methodology, and expected accuracy. These cost estimates are intended to support determinations by DOE and hydropower facility owners as to which facility upgrades are worthy of further studies. Such studies are beyond the scope of this report, but would develop refined (Class 3 – Budget Authorization) cost estimates and refined benefit and value results to support budget authorizations for capital or major process improvements at the hydropower facilities that have been assessed.

The Duke Energy Rhodhiss hydro plant has three (3) units that have been in commercial operation since 1925. From 1999 to 2002, several upgrades were completed to Units 1 and 2 as part of Duke Energy's HydroVision program. Unit 3 did not receive significant upgrades, and is only operated during high water events, very high demand periods, or outages for Units 1 and 2. Units 1 and 2 are automated while Unit 3 must be manually started. The overall condition of the Rhodhiss units and plant is fair (the CIs fall within the range of $3 \leq CI \leq 7$), although many technological features still in use date back to the original construction over 85 years ago, and further evaluation and assessment of the facility and its operations is warranted.

During the years between 2007 and 2011, the Averaged Actual Power Production (APP) was 6.32 MW based on the historical operations records, while the Long-Term Stream Power (LTSP) was 7.78 MW for the Rhodhiss site. The potential plant generation improvements due to plant efficiency improvements from optimized plant dispatch, while producing the same power at the same time, averaged about 2.3% for the analyzed years. The potential generation improvements from using the available water at the peak plant efficiencies averaged about 4.7%. The potential generation improvements from the combination of optimized plant dispatch, improved scheduling, and state of the art turbines and generators averaged about 9.8%.

There are several opportunities at Rhodhiss to apply updated technology to improve unit and plant efficiency and reliability, as well as opportunities for performance process improvement. Specific recommendations that highlight these opportunities include:

- A more modern hydraulic design and improved method of delivering aeration through the turbine runner may provide significant efficiency improvements. Aeration-related performance testing should be conducted, and additional performance analyses should be completed to investigate the effects of aeration on the current performance level and to estimate the anticipated effects of aeration on the potential performance level.
- Cast iron runners on Units 1 and 3, as well as Unit 3 gates and bushings, are approaching the end of their service lifetimes and should be replaced or rehabilitated.
- The exciter replacement project for Unit 3 should be completed, eliminating losses associated with the exciter field and improving exciter response.
- Assuming that the GSU transformers are to continue to remain in service for a length of time, a proper dry out and oil reclamation is recommended.
- In order to provide the most efficient utilization of the available water resources, new generator efficiency curves should be developed and used in determining the optimal generation mix.
- As a means to achieve added efficiency improvement, the plant should develop a routine method for monitoring and cleaning the trash racks and removing debris.
- The Unit 3 control system upgrade should be completed to allow this unit to participate in plant operations as needed.

1.0 Introduction

This condition and performance assessment report presents results of the second in a series of evolving standard assessments in the development of the Hydropower Advancement Project (HAP) standard assessment methodology. The priority objectives for this report are to document the condition and performance of the facility and its components and identify the improvements that should be examined in subsequent cost-benefit estimation and prioritization activities. The report includes approximate cost estimates with AACEI Class 5 (concept screening) characteristics of project definition, end usage, methodology, and expected accuracy (see DOE G 413.3-21). These cost estimates are intended to support determinations by DOE and hydropower facility owners as to which facility upgrades are worthy of further studies. Such studies are beyond the scope of this report, but would develop refined (Class 3 – Budget Authorization) cost estimates and refined benefit and value results to support budget authorizations for capital or major process improvements at the hydropower facilities that have been assessed.

1.1 Objective and Scope of Assessment

The objective of HAP assessment is to identify the potential for asset improvements (including expansion) and the opportunity for operational process improvement at the Rhodhiss Hydropower facility. The HAP evaluation includes both the performance and condition assessments. The performance assessment is to quantify unit and plant performance and to investigate the opportunities for operations-based, equipment-based, and maintenance-based performance improvements leading to additional generation. The condition assessment aims to quantitatively evaluate the condition of plant assets. The scope of assets for HAP assessment include all major components in mechanical, electrical, civil, and instruments & controls (I&C) systems, as well as some auxiliary mechanical components in the plant. Eventually, the assessment results will be aggregated from all assessed facilities to characterize and trend the asset conditions across different facilities, owner fleets, regions, and overall U.S. hydropower fleet, and also to correlate the performance to the condition ratings.

1.2 Plant General Information

The Rhodhiss Hydropower Facility is located in Burke and Caldwell Counties, North Carolina on the Catawba River. The facility, with reservoir and all appurtenances, was constructed and commissioned in 1925 by Western Carolina Power Company and conveyed to Duke Power

Company in 1927, and is currently owned and managed by Duke Energy Corporation. The original purpose of this facility was for power generation only. Currently, it is also used for recreation and municipal water supply, but there is no flood control requirement.

The Rhodhiss hydropower facility consists principally of an un-gated mass-concrete Ogee spillway, an integral concrete intake-powerhouse structure, and concrete gravity non-overflow bulkheads, which impound a narrow and long lake with approximate 3,060-acre of water surface area. There are three Francis turbine generating units in the powerhouse with design net head of 59 feet, utilizing the impounded water to produce electricity. The original nameplate capacity was 8.5 MW per unit (26 MW in total). Unit 2 was uprated to 10.7 MW, so the current plant power capacity is 28.2 MW.

The significant refurbishment, rehabilitation and upgrading events at the Rhodhiss facility are listed as follows:

- 1985 – Reconstruction of upper 15 ft and entire downstream slope of earth embankment.
- 1989 – Installation of riprap and drainage pipe along earth embankment downstream of the left training wall and adjacent to warehouse building; installation of riprap to protect a portion of the left bank of the tailrace.
- 1991 – Installation of alignment monuments and survey stations for deformation surveys.
- 1998-1999 – Refurbishment of three head gates, installation of new trash racks, and shotcrete repair of intake deck beams.
- 1999 – Refurbishment of powerhouse crane.
- 2000-2001 – Upgrades for spillway, bulkheads, and downstream abutment.
- 2006 – Completed rehabilitation and upgrades of turbine generators for Units 1 and 2 as part of Duke's system wide HydroVision Program. Unit 2 received the complete mechanical/electrical upgrade package including an upgraded turbine, control upgrades, auxiliary system upgrades, and a generator rewind. Unit 1 received a turbine overhaul, control upgrades, auxiliary system upgrades, and generator rewind. Unit 3 did not receive any major efficiency or capacity upgrades.

Since the HydroVision rehabilitation and upgrades, Units 1 and 2 may be remotely controlled and operated 24x7 from Duke's centralized hydro operating center in Charlotte, NC. Units are typically run at best efficiency or can be moved back to synchronous condense mode to assist with load following needs. Because there is excess capacity at the Rhodhiss plant, Unit 3 is

generally only operated during high water events, very high demand periods, or outages for Units 1 and 2. However, there are plans to upgrade Unit 3 with a new aerating runner and designate it as the primary operating unit.

Figure 1.1: Rhodhiss Hydropower Station

1.3 Site Visit and Acknowledgment

The first task in completing a facility assessment is to collect information and data for the team to review prior to the on-site assessment. The Rhodhiss plant management team was very cooperative and provided invaluable assistance in gaining access to information, sharing their plant experiences, coordinating interviews with plant personnel and providing escorts for tours of the facility. During the site visit, Greg Lewis (Technical Manager of Duke Energy for Hydro Fleet) did a presentation to introduce the plant history and operations, Greg Blevins (Mechanical Engineering), Earl Brinson (Electrical Engineering) and other plant personnel were interviewed to answer the questionnaire about the plant and unit condition and operations. Representatives of Mesa Associates did a pre-assessment visit in July of 2011 to collect the plant design and operation information. A team of experienced engineers and experts from Mesa Associates and ORNL performed the site visit on August 1st, 2011. During the inspection walk down, Unit 1 was the only unit generating energy.

2.0 Condition Assessment

2.1 Civil/Structural Components

The civil/structural portion of the assessment is limited to the following features/components:1) trash racks and intakes; 2) penstocks; and 3) leakage and releases.

The primary structure of the Rhodhiss dam is a mass-concrete Ogee spillway 800 ft long by approximately 72 ft high. The rectangular-shaped intakes are submerged and have rectangular butterfly valve intake gates which are operated through a shaft at the top of the dam. There are three separate intakes, one for each turbine with two headgates and steel trash rack sections per intake. The penstocks are short and rectangular shaped consisting of primarily exposed concrete and are integral with the dam structure. There is no control/shut-off valve installed at the turbine inlet because the intake valves can provide closure for the short penstock of each individual unit. There are no draft tube gates. There is no flume or open channel for upstream water conveyances and the tailrace is short and excavated in the river channel. The tailwater is backwater from Lake Hickory.

2.1.1 Observations and descriptions

Trash Racks

The primary objective of the trash racks assessment is to determine if the condition of the trash racks or accumulated debris across the racks is responsible for reduced efficiency at the units. The trash racks for all three units were replaced in 1998-1999 as part of the Hydrovision program. The new racks are surface mounted. Prior to replacement, trash buildup was a significant problem at the plant. There is currently no trash rack monitoring. The existing method for removing surface trash is the use of a small trash chute. However, this only handles small trash and debris. Larger items such as logs are removed when there is a spill over the open Ogee spillway, which occurs every couple of years. A trash boom had been scoped for the Hydrovision program, but it was deleted from the final project scope and never installed.

It is important to routinely inspect the condition of the trash racks. If there is significant trash/debris buildup across the rack the energy (head) loss can affect the overall plant efficiency. Routing monitoring of the head differential across the trash racks can be used to schedule trash cleaning. Because there is a history of trash buildup at Rhodhiss, it is recommended that the plant perform routine monitoring and cleaning of the trash racks.

Intakes

The primary goal of the intake structure and headgate inspection is to determine if there are any existing deficiencies or potential upgrade opportunities which could affect overall plant efficiency and reliability. Because both the intakes and penstocks are similarly shaped limiting any abrupt geometrical changes and are relatively short, replacement/addition of a liner would only provide a minimal decrease in head loss and have little impact on overall plant generation performance. Also, because the intake gates are butterfly valve gates and have no gate slots, head losses due to surface irregularities are limited. It is recommended that for general maintenance and reliability purposes, the interior of the intake be regularly inspected and properly maintained to avoid flow obstructions. No special intake flows were observed during the site visit. The headgates were not observed during the site visit and the current condition is unknown.

Penstocks

The primary goal of the penstock inspection is to determine if there are any existing deficiencies or potential upgrade opportunities which could affect overall plant efficiency and reliability. As with the intake, replacement/addition of a liner in the penstock would only provide a minimal decrease in head loss through such a short water conveyance system and have little impact on overall plant generation performance. It is recommended that for general maintenance and reliability purposes, the interior of the penstock be regularly inspected and properly maintained to avoid flow obstructions.

Leakage and Releases

The primary goal of this portion of the inspection is to identify any unregulated or unmeasured leakage which could impact plant generation. According to plant personnel, there is currently no minimum flow requirement but only a daily minimum discharge which is met by daily generation. The normal flow of the river is managed by Units 1 and 2. Unit 3 is usually only run during very high demand periods or when there is the potential for spilling.

The plant will be expected to comply with North Carolina's dissolved oxygen (DO) requirements when a new license is issued. However, the existing plant configuration has limited ability to enhance DO. There are plans for installation of an aerating runner for Unit 3 in the future. In addition, to help with the DO requirements, the plant has supplemental air inlet valves that can open along with the turbine vacuum breakers to allow air through the hollow stay vanes and discharge below the runner.

A small amount of leakage from the wicket gates on Unit 2 was observed. However, the leakage is not significant and does not present an efficiency issue.

The foundation rock is an igneous formation and does not appear to be susceptible to seepage and erosion. There was also no evidence of leakage from the dam structure or surrounding abutments.

Based on the information gathered during the assessment, it is our opinion that the plant does not have a significant issue with leakage and releases. We have no recommendations as to how to improve plant efficiency in respect to this feature.

2.1.2 Condition assessment results

The condition assessment results for Trash Racks and Intakes of the three units, Penstocks of the three units, and Leakage and Releases for the overall plant are shown in Tables 2.1, 2.2, and 2.3, respectively. No noticeable difference was found among the three units for the current condition of trash racks and intakes, penstocks, and leakage and releases. Thus, the values of condition indicators of the three above-mentioned civil components were approximately the same for the three units. They all are around 5.5, which indicates a fair overall condition of civil portions of the Rhodhiss hydropower facility. However, the Data Quality Indicators for civil portion assessment were quite low (between 2.0 and 3.0), suggesting a high uncertainty and low confidence on the civil condition assessment results, due to lack of archived historical O&M records, the lack of dewatering for visual inspections during the site visit and the unclear scope of HAP assessment at the time of site visit.

Based on the assessment, the primary area where efficiency improvement potential exists is at the trash racks. It is recommended that further evaluation and monitoring of head loss at the trash racks be performed. Because trash build-up has posed a problem in the past, it is important that the plant develop a routine method for monitoring and cleaning the racks and removing debris.

The above observations, comments and recommendations are based on the following limitations and exclusions:

- Dewatering of the water conveyance system was not done for this assessment; therefore, direct inspection of the penstock and intake interiors was not possible. Dewatering is typically done every 3 years for inspection of the runner, scroll case, and penstock; however, no inspection reports were available.
- There is currently no trash rack monitoring. Trash racks were not accessible for direct inspection.

2.2 Mechanical Components

Description of turbine-generator units:

- Commercial Operation (Units 1, 2, and 3): February, 1925
- Head: Normal gross head of 60.5 ft.
- Turbines: Vertical Francis type, 100 RPM: Units 1 and 3 - S. Morgan Smith, 11,700 HP at 60.5 ft. gross head; Unit 2 - American Hydro, 14,800 HP at 60.5 ft. gross head. Centerline of distributor – EL 485 ft. Lake elevations at day of inspection: Headwater – 996.86 ft, Tailwater – 937.21 ft.; gross head of 59.65 ft.
- Generator: Westinghouse, Units 1 and 2 - 13,000 KVA, 12.35 MW @ .95 PF; Unit 3 – 10,625 KVA, 8.5 MW @ 0.8 PF; Suspended design with thrust bearing above the generator rotor.

2.2.1 Observations and descriptions

<u>Turbine Runner</u>

There are no OEM drawings for the Units 1 and 3 turbines, but Duke Engineering stated that the runners were manufactured from cast iron and the original equipment is still in use. In the HydroVision program, the runner from Unit 2 was replaced with a new composite runner (carbon steel crown, stainless steel buckets and band) manufactured by American Hydro Inc. in 2000 (see Figure 2.1). The Unit 2 rotating seal rings (or wear rings) attached to the outside diameter of the runners are fabricated from stainless steel. The opposing Unit 2 stationary seal rings mounted in the headcovers and bottom rings are bronze. Units 1 and 3 original seal rings are thought to be cast iron. According to plant personnel, the Unit 1 cast iron runner was not replaced in the HydroVision program due to the lack of funding.

Proprietary Drawing

Not available in public version of report

Figure 2.1: American Hydro Drawing for Unit 2

To address dissolved oxygen (D.O.) levels downstream, Rhodhiss discharges air from the turbine through the augmented vacuum breaker systems in Units 1 and 2. The OEM vacuum breaker system in Units 1 and 2 was changed from a sleeve valve (Figure 2.2) operated by a linkage to the wicket gates, to a motor operated valve (Figure 2.3) controlled by the plant automation system. Air is drawn in through the vacuum breakers of all three units via hollow stay vanes and discharges between the runner bands and parking ledges. The plant personnel indicated this method yielded a good D.O. uptake. The problem with this system is a drop in unit efficiency due to the intake of air into the turbine. A more modern hydraulic design and improved aeration method through the runner may provide significant efficiency improvements.

According to plant personnel, cavitation erosion has been only a minor problem. After 86 years of service, the Units 1 and 3 cast iron runners are expected to be at the end of their service life and are candidates for replacement.

Wicket Gates

Although no drawings with material specifications were found, Duke Engineering believes the wicket gates are manufactured from cast steel. Although the gates are original equipment, the

Unit 1 and 2 gates were rehabilitated during the HydroVision program. The stem journal bushings were originally greased bronze and were replaced with greased bronze in Units 1 and 2. After 86 years of service, the Unit 3 gates are expected to be at the end of their service life and are candidates for rehabilitation or replacement. Some surface rehabilitation, such as coatings, and shape re-profiling of the wicket gates (all three units) may provide some efficiency improvements.

Stay Vanes

Although no drawings with material specifications were found, it is usual practice to manufacture stay vanes from cast iron. After 86 years of service some surface rehabilitation, such as coatings, and shape re-profiling may provide some efficiency improvements.

Spiral Case

Duke Engineering stated that the spiral casings are un-lined concrete. After 86 years of service, surface rehabilitation may provide some efficiency improvements.

Draft Tube

Duke Engineering stated the draft tube is mostly un-lined concrete with only a small section near the turbine discharge lined with carbon steel. Further studies may indicate some efficiency improvements from draft tube modifications. However, because there are no draft tube gates, performance improvement with slot fillers is not applicable.

Vacuum Breaker

The Unit 3 vacuum breaker is original equipment and, based on discussions with plant personnel, the breakers have not been overhauled since being placed in commercial operation. The Unit 3 vacuum breaker is actuated from the wicket gate shifting ring (Figure 2.2) which normally closes the breaker above a specified gate opening to prevent a reduction in unit efficiency. In this case, the shifting ring turns clockwise (looking down, Figure 2.2) to open the wicket gates and close the vacuum breaker.

The OEM vacuum breaker systems in Units 1 and 2 were changed from a sleeve valve (Figure 2.2) operated by a linkage to the wicket gates, to a motor operated valve (Figure 2.3) controlled by the plant automation system. Air is drawn in through the vacuum breakers of all three units via hollow stay vanes and discharges between the runner bands and parking ledges.

Figure 2.2: Original vacuum breaker at Unit 3 (One for each unit)

Figure 2.3: Modified vacuum breakers Units 1 and 2 (Two for each unit)

Generator Mechanical

The generator is a Westinghouse open frame design (Figure 2.4), typical of that era. It is a suspended design with the thrust bearing above the generator rotor and has two generator guide bearings (one above and one below the rotor). With an open frame design, the stator and rotor are air cooled by drawing outside air through the units with no water-to-air external cooling system. Outside air is drawn into the wheel pit area, up into the generator rotor and moved out through the stator frame. Units 1 and 2, which have been modernized in the HydroVision program, have a unique filtering system (Figure 2.5) added to the wheel pit doors to help keep the generator clean from dirt and insects. Keeping the internal portions of the generator clean helps to maintain proper cooling and to minimize windage losses.

Because all three units are open framed, there are no air coolers and associated raw water piping to inspect.

Judging from the age of the technology, a performance gain most likely could be achieved by adding air housing around the stator, air to water cooling, and ventilation baffling. Duke Engineering stated such options were considered during HydroVision, but were determined to not be cost effective given the limited inflows.

Figure 2.4: Generator of Unit 3

Figure 2.5: Wheel Pit Door Filters

Turbine Governor

The Rhodhiss Units 1 and 2 have Russelectric digital governors (Figure 2.6). These are digital hydraulic governors which control each turbine through servomotor-operated wicket gates. The governor receives its speed indication from a speed sensor mounted on the shaft. The governor oil pressure is supplied by a governor hydraulic package consisting of two 15-HP, AC motor-driven, positive displacement pumps with a nitrogen gas pressure accumulator. The two governor motor-pumps are redundant and alternate in lead-lag sequence under normal operation to equalize load.

Unit 3 has the original gate-shaft mechanical governor (Figure 2.7).

Figure 2.6: New Digital Governor at Unit 1 and Unit 2

Figure 2.7: Original Mechanical Governor at Unit 3

Lubrication System

No assessment condition data was collected because the overall scope of HAP assessment was unclear at the time of the site visit.

Raw Water (Cooling) System

No assessment condition data was collected because the overall scope of HAP assessment was unclear at the time of the site visit.

2.2.2 Condition assessment results

The condition assessment results for Francis Turbines and turbine Governors are shown in Tables 2.1, 2.2 and 2.3, respectively, for each of the three units. Reflecting the different levels of upgrading and modernization among the three units, the Unit 2 turbine was scored 7.01 for its condition indicator, which indicates a good condition of Unit 2. Turbines for Units 1 and 3 were rated 5.72 and 5.31 respectively, indicating a fair condition of both turbines. The turbine governors of Units 1 and 2 have been modernized and thus the condition indicators of 8.26 were obtained while the original Unit 3 governor got a lower score of 5.15 (fair condition). The Data Quality Indicators of mechanical components were relatively higher than the civil portions, and indicated a lower uncertainty and higher confidence on the mechanical condition assessment results, due to more available data and information used for condition assessment.

It was interesting to note the contrast of unit configurations and conditions between the three originally identical units as a result of a partially completed modernization program. Units 1 and 3 are still operating with original cast iron runners while Unit 2 has a new runner. The generator stators for Units 1 and 2 have been rewound, and new solid state excitation, new governors and hydraulics, and hydrostatic “lift” systems on thrust bearings were added to the units. In contrast, mechanically Unit 3 is completely original equipment. None of the units have shear link failure annunciation systems or automatic greasing systems for the wicket gates. Greasing is performed manually by technicians on a monthly schedule. Because Units 1 and 2 are automated and Unit 3 must be manually started, most of the plant’s generation is accomplished by operating Units 1 and 2.

Units 1 and 2 have a somewhat modern shaft vibration monitoring system (Bently Nevada 3300) with four vibration probes per unit in the preferred configuration of two probes mounted in the X and Y positions located near the generator guide bearing and two probes on the same planes located near the turbine guide bearing. Unit 3 does not have a shaft vibration monitoring system.

Unit 1 was the only unit generating power during the inspection. Unit 3 was operated as a demonstration to the assessment team as plant personnel had noted a high level of piercing noise emanating from the unit (the assessment team and HAP methodology authors will be considering further revisions to the rating scales and/or structure that will address the challenges imposed by excessive operating noise from generators or other components). Unit 1 came on line at 13:30 pm and after about 1-½ hours, the unit temperatures, as displayed on the control room automation screen, looked normal.

The following are our recommendations for the major mechanical plant features:

- A more modern hydraulic design and improved method of delivering aeration through the turbine runner may provide significant efficiency improvements.
- According to plant personnel, cavitation erosion has been only a minor problem. After 86 years of service, the Units 1 and 3 cast iron runners are expected to be at the end of their service life, and are candidates for replacement.
- After 86 years of service, the Unit 3 gates are expected to be at the end of their service life, and are candidates for rehabilitation or replacement. Some surface rehabilitation, such as coatings, and shape re-profiling of the wicket gates (all three units) may provide some efficiency improvements.
- Regarding the stay vanes, after 86 years of service, surface rehabilitation, such as coatings, and shape re-profiling may provide some efficiency improvements.
- Further studies may indicate some efficiency improvements from draft tube modifications. However, because there are no draft tube gates, performance improvement with slot fillers is not applicable.

It is readily apparent that the technology still in use dated to the early 1920's, such as cast iron runners, mixed with more modern equipment on the units which have undergone modernization. Clearly there are opportunities at Rhodhiss to use updated technology to not only improve unit efficiency and performance but also the reliability. A more thorough study of the historical data and a complete crawl-through inspection with the unit un-watered would yield a more complete plant condition assessment addressing performance, maintenance, and reliability issues.

The above observations and recommendations are based on the following exclusions, assumptions, and limitations:

- Written maintenance records were not readily available during the inspection. There are no OEM drawings for the original turbine and generators. The only available turbine

drawings are from the HydroVision (hydro modernization) program replacement of the Unit 2 turbine runner in the year 2000. Units 1 and 2 underwent modernization in the HydroVision program but Unit 3 modernization is still pending. Historical events presented below are mainly from the discussions with and recall of the plant personnel. However, note that the plant personnel appeared very knowledgeable of the recent plant maintenance history.

- Inspection of the power train was limited to that which could be viewed from a walkthrough of the plant. Generator access was limited to what could be viewed outside of the stator frame (open frame unit). The turbine's draft tube and spiral casing doors were closed, so direct inspection of the turbine runner, draft tube, wicket gates, stay vanes, and spiral case were not possible.
- Observations and conclusions are based on Mesa's experience with hydro mechanical components and normal industrially accepted operational, maintenance, and rehabilitation practices.

2.3 Electrical Components

The electrical power train components reviewed for the electrical assessment include the generator stator and rotor, exciter, and generator step up transformers. The generators are Westinghouse open frame units. All units were rehabilitated in the early 2000s with Units 1 and 2 stators rewound (class F insulation), cores restacked, and rotors reinsulated (class F insulation). Unit 3 generator stator and rotor were rewound and the core restacked in 1987. The exciters for Units 1 and 2 were replaced with General Electric (GE) static exciters in early 2000s. Unit 3 was not rerated but retained the original rating of 10625 KVA @ .8 power factor (pf). Units 1 and 2 were rerated to 13000KVA @ .95 pf.

The three generator step-up transformers were manufactured by Westinghouse Electric Company in East Pittsburgh, Pennsylvania in 1925. The 3-phase transformers are rated 88-6.6-kV, 10.6 MVA. The transformers were originally internally water cooled and were converted to an OA rating when radiators were added in 1992. Each transformer has a temperature rise rating of 40° C at 100 percent load and 55° C at 125 percent load. The oil preservation system appears to be of the free breather type.

2.3.1 Observations and descriptions

Generator

The recent rehabilitation of all units provides improved reliability and should also have reduced losses, particularly for Units 1 and 2 with redesigned windings. This assumes use of lower loss steel in the cores and increased copper cross-sections in the winding. Original and new design data and guaranteed loss data was not available for comparison. Unit 1 was being operated at approximately 9.32 MVA, 75% gate at the time of the walk down. None of the available temperature data was outside expected values.

Figure 2.8: Generator for Unit 3

All generators are open framed air-cooled utilizing filtered cooling air, as shown in Figure 2.8. The backside(s) of the cores appeared clean and in good condition in the observed areas.

Exciter

The excitation systems have been upgraded on all units with the rewind to class F insulation of the generator rotors and the installation of solid state exciters on Units 1 and 2. The solid state exciters are located adjacent to the units and the unit control cabinets on the operating floor and subject to uncontrolled ambient conditions. As can be seen in Figure 2.9, the field poles and commutator brushes have been removed, eliminating potential losses (heat) and maintenance items associated with them as well as improving exciter response with the new system for Units 1 and 2. Note that the cable coming from the box over the collector rings appears to be coming through an unprotected hole (i.e. no grommet or cable clamp) and may be subject to eventual wear through. Material condition of the excitation system components appeared good.

Figure 2.9: Unit 1 Exciter and Exciter Cabinet

Main Transformers

GSU 1

Dissolved Gas Analysis (DGA) samples are drawn annually with the results recorded and trended in a data base. There were several gases that were elevated. The elevated hydrogen noted on several samples and from the historic data is likely from electrolysis due to the elevated moisture within the transformer. The elevated carbon monoxide and carbon dioxide is likely from aging and deterioration of the cellulose insulation and elevated oxygen. The hot metal gases (methane, ethane, and ethylene) are within acceptable ranges and no detectable levels of acetylene were noted on current samples. Elevated acetylene was noted on the trend chart around 2005, but no historic fault data was provided to evaluate. The current dissolved oxygen is within the acceptable levels of < 5% for all but one sample period, but the historic data indicates several samples above this level. If the oil preservation system is of the free breather type, this would explain the elevated oxygen levels as atmospheric air is in contact with the insulation oil. If the oxygen levels were elevated in earlier years, as noted on the trend charts, the elevated carbon monoxide results could be affected from this as well. The total dissolved combustible gas level is above standard limits, but this is being driven by the elevated carbon monoxide results.

Insulating oil quality analysis samples are drawn annually with the results recorded and trended in a data base. The trend analysis data indicates the oil to be in less than marginal condition. The acid number is elevated and above acceptable limits and the interfacial tension has decreased below acceptable limits as shown on the trend charts indicating that the oil is oxidized. The color also supports oxidation of the oil. Sludge could be forming within the transformer which can damage insulation and block cooling ducts. Inconsistencies were noted at times between the acid number and the interfacial tension. The dielectric strength of the oil is

less than acceptable and the moisture content of the oil is extremely high in nearly all samples indicated on the trend charts. The percent saturation trends indicate that the transformer is wet. Some oil work may have been performed around 2004, but if so the problems still exist.

Figure 2.10: Switch Yard Photo

Power factor test data was provided for the main transformer insulation as well as the associated bushings. The overall winding insulation ratings were noted as “bad” with significant elevated power factors indicated at 10 percent and above. Acceptable power factor ratings are usually 0.5 percent or less. The CH, CHL, and CL tests all exhibited elevated power factors indicating contamination and deterioration throughout the main insulation system. The contamination is likely from a combination of aged and wet insulation. The HV bushing power factors appeared to be within acceptable limits for the C1 and C2 tests.

GSU 2

The hot metal gases (methane, ethane, and ethylene) seen in the DGA are within acceptable ranges and no detectable levels of acetylene were noted on current samples. The elevated carbon monoxide and carbon dioxide is likely from aging and deterioration of the cellulose insulation and elevated oxygen. The current dissolved oxygen is greater than acceptable levels of < 5% for all but one sample period. Elevated oxygen levels accelerate the aging process. The historic data indicates several samples above this level as well. If the oil preservation system is of the free breather type, this would explain the elevated oxygen levels as atmospheric air is in contact with the insulation oil. If the oxygen levels were elevated in earlier

years, as noted on the trend charts, the elevated carbon monoxide results could be affected from this as well. The total dissolved combustible gas level is above standard limits, but this is being driven by the elevated carbon monoxide results.

The trend analysis of oil quality data indicates the oil to be in less than marginal condition. The acid number is elevated and above acceptable limits and the interfacial tension has decreased below acceptable limits as shown on the trend charts indicating that the oil is oxidized. The color also supports oxidation of the oil. Sludge could be forming within the transformer which can damage insulation and block cooling ducts. Inconsistencies were noted at times between the acid number and the interfacial tension. The dielectric strength of the oil is less than acceptable, and the moisture content of the oil is extremely high in nearly all samples indicated on the trend charts. The percent saturation trends indicate that the transformer is wet. Some oil work may have been performed around 2006 - 2007, but if so the problems still exist.

The overall winding insulation ratings were noted as “investigate” with current power factors listed above 3.0 percent. Acceptable power factor ratings are usually 0.5 percent or less. The CH, CHL, and CL tests all exhibited elevated power factors indicating some contamination within the main insulation system. The contamination is likely a combination of aged and wet insulation. The HV bushing power factors were elevated on the H2 bushing for both C1 and C2. The H3 bushing results appear to be satisfactory. No test results were provided for the H1 bushing.

GSU 3

DGA showed hot metal gases (methane, ethane, and ethylene) within acceptable ranges and no detectable levels of acetylene were noted on current samples. The elevated carbon monoxide and carbon dioxide is likely from aging and deterioration of the cellulose insulation and elevated oxygen. The current dissolved oxygen is within the acceptable levels of < 5% for nearly all sample periods. The historic data indicates several samples above this level. If the oil preservation system is of the free breather type, this would explain the elevated oxygen levels as atmospheric air is in contact with the insulation oil. If the oxygen levels were elevated in earlier years the elevated carbon monoxide results could be affected from this as well. The total dissolved combustible gas level is above standard limits, but this is being driven by the elevated carbon monoxide results.

Oil quality analysis trend shows the oil to be in marginal condition. The acid number is elevated with low interfacial tension as shown on the trend charts indicating that the oil is oxidized. The

color also supports oxidation of the oil. Sludge could be forming within the transformer which can damage insulation and block cooling ducts. Inconsistencies were noted at times between the acid number and the interfacial tension especially in later years. These should be look into as acid numbers of 0.2 are usually associated with interfacial tension numbers less than 27. The dielectric strength of the oil is less than acceptable, and the moisture content of the oil is extremely high in nearly all samples indicated on the trend charts. The percent saturation trends indicate that the transformer is wet. Some oil work may have been performed around 2004 - 2005, but if so the problems still exist.

The overall winding insulation ratings were noted as “investigate” with current power factors listed above 2.0 percent. Acceptable power factor ratings are usually 0.5 percent or less. The CH, CHL, and CL tests all exhibited elevated power factors indicating some contamination within the main insulation system. The contamination is likely from deteriorated and wet insulation.

The HV bushing power factors were all noted to be within an acceptable range.

2.3.2 Condition assessment results

The condition assessment results for Generators, Exciters and Transformers are shown in Tables 2.1, 2.2, and 2.3, respectively, for each of three units. The Generator condition was rated 5.48, 5.48, and 5.01, respectively, for Units 1, 2, and 3[1]. The Exciters got the condition scores of 7.36, 7.36, and 3.06, respectively, for Units 1, 2, and 3. All the three main Transformers were rated 4.08. Some electrical portions of Rhodhiss plant are relatively at a poor condition, and upgrading or replacement is recommended for the reliability of power generation and lower cost of O&M.

The following are our recommendations for the electrical plant features:

- The DGA analysis data for all GSU’s does not indicate any significant major concerns at this time based on data provided for the period 2007 to 2011. Elevated levels of oxygen and carbon monoxide were noted which indicated some degradation of the cellulose insulation.
- The transformer insulating oil temperatures reported were in acceptable ranges for all GSU’s.

[1] The excessive generator noise from Unit 3 may require additional consideration within the HAP condition rating structure, depending on further assessment of its influence on unit operations and dispatch.

- For all GSU transformers, the oil is wet and oxidized. The insulation appears to also be contaminated with moisture. If the transformers are to continue to remain in service for a length of time, a proper dry out and oil reclamation would be recommended. However, due to the age of these transformers and insulation deterioration, it may not be economically feasible to pursue this. Dry out of these transformers may be challenging due to their age and also because the tanks may not be rated for vacuum.
- The winding power factor tests indicated extremely poor condition of the insulation system for GSU 1. The winding power factors for GSU's 2 and 3 indicate significant deterioration of the insulation system. Although the insulation system is wet, it is also 86 years old and well beyond the expected useful service life. Based on experience, one would expect the insulation to be quite brittle due to age and operating conditions and highly susceptible to failure from faults.
- The bushing power factors on GSU 2 are elevated and should be further evaluated to nameplate data.
- Consideration should be given to the scheduled replacement of these 86 year old GSU transformers to provide for future reliability and efficiency.
- Protection for collector rings on Unit 3 is recommended, as done on Units 1 and 2 (risk from overhead suspended loads).
- Exciter replacement for Unit 3 is recommended. This will eliminate losses associated with the exciter field and improve exciter response.

The above observations, comments and recommendations are based on the following limitations and exclusions:

- Furanic or oxidation inhibitor test data was not provided for evaluation of GSU insulating oil quality.
- No GSU bushing nameplate data was provided. Comparative analysis could not be performed on C1 or C2 power factors due to lack of nameplate data. The capacitance test values were noted, but no nameplate capacitance values were listed for comparison. Therefore, the capacitance data could not be evaluated.
- Insulating oil quality analysis data was provided for the period 2007 - 2011. Historic trend charts were provided for the period 1998 – 2011 for all GSUs.
- DGA historic trend charts were provided for the period 1995 – 2011 for all GSU's.
- GSU winding and bushing power factor electrical test data was provided for the period 1992 - 2011. No core excitation, winding resistance, or factory test data was provided.

- No maintenance, fault, or failure history was provided for the GSU transformers.
- No indication that an on-site or system spare transformer is available for this location.
- No electrical test data, failure, or maintenance history of the generators or exciters was available for review.
- Unit 1 was operating at approximately 9.32 MVA during the walk down. The other two units were out of service; however, Unit 3 was temporarily run during the walk down as a demonstration.

2.4 Instruments and Controls System

This I&C assessment is based on visual inspection of the control room and plant instrumentation during the site visit and interviews with plant personnel on how the plant is operated. No direct measurements or calibration efforts were included.

2.4.1 Observations and descriptions

A shown in Figure 2.11, the plant automation system is based on the mix of old and new instrumentation.

Figure 2.11: Instrumentation and Controls

Instrumentation for each of the three generating units includes generator kilovolts, amps, Megawatts, Megavars, field voltage, field current, rpm and gate position. A sample generator control screen is shown in Figure 2.12. A unique feature of the control screen is the duplication of the manual generator controls in control system software. This reduces the potential for error when manually operating the generator either from the control room or locally at the generator.

The data from the plant instrumentation is monitored by the operators at a central control console. The generators can be remote started from the Charlotte operating center. However, due to its current condition, Unit 3 is only operated manually by on-site plant personnel. The hourly operating schedules for Units 1 and 2 are determined by the Hydro Central operations group. Total plant efficiency is not a primary consideration in making this determination. Plant instrument calibration is verified annually.

There is an SOE (sequence of events recorder), but it is not tied to the PLC system. To access trip information and first outs, one must log into the SOE computer.

Historical data is collected in the PI (OSI) historical archive. It is available at both the central control as well as at the plant.

The condition monitoring is Bently-Nevada. There are hard wire trips to the control system to protect the units. The vibration monitoring appears to be minimal, but adequate for these small units. There is no discharge flow measurement.

There is no automatic supervisory control to optimize generation. Each unit, at all plants, must be started or stopped individually. A schedule is created for operations to manually start and stop units either locally or from central control to meet anticipated demand. Efficiency of operations appears to be of minimal concern at Rhodhiss as these units are small.

The plant process control network is protected by a firewall. There is no network redundancy. The firewall appears to be maintained by the IT group. The control network is separated from the business network.

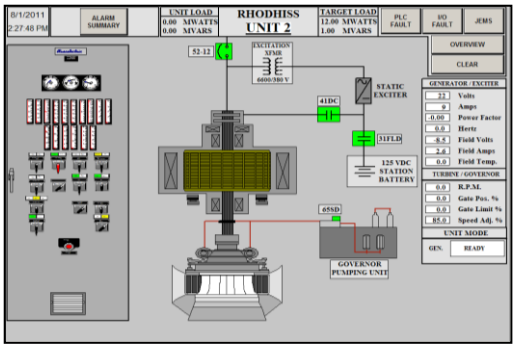

Figure 2.12: Generator Control Screen

2.4.2 Condition assessment results

The condition assessment results for the Automation and Instruments are shown in Tables 2.1, 2.2, and 2.3, respectively, for each of three units. The condition indicators of Instruments were 5.0 for all three units, because there was no noticeable difference found among the three units. The other parts of Automation System were rated 5.89 for Units 1 and 2 and 3.5 for Unit 3, as the automation of Unit 3 was not done. The overall condition indicator of the I&C system is the weighted sum of Instruments and Automation (reference to Guide for I&C Condition Assessment), resulting in the condition indicators of 5.71 for the Unit 1 and 2 I&C system and 3.80 for the Unit 3 I&C system.

The following recommendation pertains to the plant automation system:

- To provide the most efficient utilization of available water resources new generator efficiency curves should be developed and used in determination of the optimal generation mix.
- Plans should begin to upgrade the control system to the newer generation of controllers. This is not critical but parts may eventually be hard to acquire.
- Unit 3 should receive a control system similar to Units 1 and 2 and be of current technology.
- SOE data is available serially and could be connected to the iFIX system for long term trending.

The above observations and recommendations are based on the limitations: 1) No direct measurements or calibration efforts were done; 2) Information based on a review of existing drawings/documentation and discussions with operation personnel.

2.5 Plant and Units Condition Assessment

The unit overall condition and data quality indicators are shown on the bottom of Tables 2.1, 2.2, and 2.3. Because the condition indicators for each unit fall within the 3≤CI≤7 range, further evaluation and assessment of the facility and its operations is warranted. Tables 2.4 and 2.5 show the aggregated condition and data quality indicators for each unit and the final overall plant condition indicators. It is evident by the overall plant condition indicator that there is potential for increased efficiency and reliability through upgrades and rehabilitation.

Table 2.1: Unit 1 – Synthesis of Component Indicators to Unit Indicators

Components	Component Code in Taxonomy	Weighting Factors *W (i)*	Condition Indicator *CI (i)* (0-10)	Data Quality Indicator *DI (i)* (0-10)
Trashracks and Intake	3.1/3.2	2.0	5.45	2.47
Penstock/Tunnel/Surge Tank	3.3/3.4/3.6	1.5	5.58	2.20
Control/Shut-off Valve	3.5	1.0	NA	NA
Flume/Open Channel	3.7	1.0	NA	NA
Draft Tube Gate	3.8	0.2	NA	NA
Leakage and Release	2.1/2.2/2.3	1.5	5.24	3.00
Turbine	4.1.1	2.0	5.72	4.44
Governor	4.1.2	1.0	8.26	6.00
Generator	4.1.3	3.0	5.48	4.23
Exciter	4.1.4	1.0	7.36	3.00
Transformer	4.1.5	2.5	4.08	4.33
Instruments & Controls	4.3	0.5	5.71	5.48
Raw Water System	4.2.4	0.5	Not Rated	Not Rated
Lubrication System	4.2.5	0.5	Not Rated	Not Rated
Unit Indicators			***5.58***	***3.79***

Note: Lubrication System, Raw Water System, Circuit Breaker, Surge Arrester, Powerhouse Crane, Station Power Service and Compressed Air System are not evaluated for this plant.

Table 2.2: Unit 2 – Synthesis of Component Indicators to Unit Indicators

Components	Component Code in Taxonomy	Weighting Factors *W (i)*	Condition Indicator *CI (i)* (0-10)	Data Quality Indicator *DI (i)* (0-10)
Trashracks and Intake	3.1/3.2	2.0	5.45	2.47
Penstock/Tunnel/Surge Tank	3.3/3.4/3.6	1.5	5.58	2.20
Control/Shut-off Valve	3.5	1.0	NA	NA
Flume/Open Channel	3.7	1.0	NA	NA
Draft Tube Gate	3.8	0.2	NA	NA
Leakage and Release	2.1/2.2/2.3	1.5	5.24	3.00
Turbine	4.1.1	2.0	7.01	5.71
Governor	4.1.2	1.0	8.26	6.00
Generator	4.1.3	3.0	5.48	4.23
Exciter	4.1.4	1.0	7.36	3.00
Transformer	4.1.5	2.5	4.08	4.33
Instruments & Controls	4.3	0.5	5.71	5.48
Raw Water System	4.2.4	0.5	Not Rated	Not Rated
Lubrication System	4.2.5	0.5	Not Rated	Not Rated
Unit Indicators			***5.75***	***3.96***

Table 2.3: Unit 3 – Synthesis of Component Indicators to Unit Indicators

Components	Component Code in Taxonomy	Weighting Factors *W (i)*	Condition Indicator *CI (i)* (0-10)	Data Quality Indicator *DI (i)* (0-10)
Trashracks and Intake	3.1/3.2	2.0	5.45	2.47
Penstock/Tunnel/Surge Tank	3.3/3.4/3.6	1.5	5.58	2.20
Control/Shut-off Valve	3.5	1.0	NA	NA
Flume/Open Channel	3.7	1.0	NA	NA
Draft Tube Gate	3.8	0.2	NA	NA
Leakage and Release	2.1/2.2/2.3	1.5	5.24	3.00
Turbine	4.1.1	2.0	5.31	4.44
Governor	4.1.2	1.0	5.15	5.00
Generator	4.1.3	3.0	5.01	4.23
Exciter	4.1.4	1.0	3.06	1.00
Transformer	4.1.5	2.5	4.08	4.33
Instruments & Controls	4.3	0.5	3.80	5.40
Raw Water System	4.2.4	0.5	Not Rated	Not Rated
Lubrication System	4.2.5	0.5	Not Rated	Not Rated
Unit Indicators			***4.87***	***3.59***

Table 2.4: Aggregated Plant Condition Indicators for Rhodhiss

Components	Unit 1	Unit 2	Unit 3	Units Average
Trashracks and Intake	5.45	5.45	5.45	**5.45**
Penstock/Tunnel/Surge Tank	5.58	5.58	5.58	**5.58**
Control/Shut-off Valve	NA	NA	NA	NA
Flume/Open Channel	NA	NA	NA	NA
Draft Tube Gate	NA	NA	NA	NA
Leakage and Release	5.24	5.24	5.24	**5.24**
Turbine	5.58	7.01	5.31	**5.97**
Governor	8.26	8.26	5.15	**7.23**
Generator	5.48	5.48	5.01	**5.32**
Exciter	7.36	7.36	3.06	**5.93**
Transformer	4.08	4.08	4.08	**4.08**
Instruments & Controls	5.71	5.71	3.80	**5.07**
Raw Water System	Not Rated	Not Rated	Not Rated	NA
Lubrication System	Not Rated	Not Rated	Not Rated	NA
Unit Condition Indicators (*UCI*)	***5.58***	***5.75***	***4.87***	
Plant Condition Indicators (*PCI*)	**5.40**			

Table 2.5: Aggregated Plant Data Quality Indicators for Rhodhiss

Components	Unit 1	Unit 2	Unit 3	Units Average
Trashracks and Intake	2.47	2.47	2.47	**2.47**
Penstock/Tunnel/Surge Tank	2.20	2.20	2.20	**2.20**
Control/Shut-off Valve	NA	NA	NA	NA
Flume/Open Channel	NA	NA	NA	NA
Draft Tube Gate	NA	NA	NA	NA
Leakage and Release	3.00	3.00	3.00	**3.00**
Turbine	4.44	5.71	4.44	**4.86**
Governor	6.00	6.00	5.00	**5.67**
Generator	4.23	4.23	4.23	**4.23**
Exciter	3.00	3.00	1.00	**2.33**
Transformer	4.33	4.33	4.33	**4.33**
Instruments & Controls	5.48	5.48	5.40	**5.45**
Raw Water System	Not Rated	Not Rated	Not Rated	NA
Lubrication System	Not Rated	Not Rated	Not Rated	NA
Unit Data Quality Indicators (*UDI*)	***3.79***	***3.96***	***3.59***	
Plant Data Quality Indicators (*PDI*)	**3.78**			

3.0 Environmental Issues and Constraints

There is currently no minimum flow requirement at Rhodhiss hydropower facility but only a daily minimum discharge which is met by daily generation. The normal flow of the river is managed by Units 1 and 2 due to the sufficient capacity. Unit 3 is usually only run during very high demand periods or when there is the potential for spilling, because Units 1 and 2 are automated and Unit 3 must be manually started.

The plant will be expected to comply with North Carolina's dissolved oxygen (DO) requirements when a new license is issued. However, the existing plant configuration has limited ability to enhance DO. To help with the DO requirements, the plant has supplemental air inlet valves that can open along with the turbine vacuum breakers to allow air through the hollow stay vanes and discharges below the runner. There are plans to upgrade Unit 3 with a new aerating runner and designate it as the primary operating unit in the future.

4.0 Electric Power System Interconnection and Context

The electric power context for the Rhodhiss facility owner, Duke Energy Carolinas, is included here to document external factors that could affect Rhodhiss dispatch and operations. Future comparative analysis of the assessment results reported herein with those from other facilities having different context will be made. Thus, the context for facility dispatch and operations is important that will be required to understand difference in results among assessed facilities. The location of the facility with in the transmission system topology, the type and prevalence of generation assets in the balancing authority area for the facility, and the nature of the demand within the balancing authority are all relevant to the interpretation of hydropower facility dispatch, performance, and condition data and results.

4.1 Background on DEC

Duke Energy Carolinas (DEC), LLC is a subsidiary of Duke Energy Corporation. Duke Energy Carolinas utilizes a diverse range of resources to meet system needs including renewable, nuclear, coal, gas, energy efficiency, and demand side management. Still, a number of environmental regulatory issues are converging as the Environmental Protection Agency (EPA) proposes new rules to regulate multiple areas related to coal generation resources. These new rules will increase the need for the installation of additional emission control technology and will lead to the retirement of many coal-fired generators in the timeframe of 2014 to 2018, reducing the generation capacity by as much as 890 MW. Currently, the economic recession continues to impact the projected load forecast though 2015 with the projected reserve margins exceeding the 17% planning reserve margin than 2014. However, with the upcoming projected retirement of all non-scrubbed coal by 2015, Duke's projected reserve margin may quickly drop below or to target planning reserve margins.

The 2010 Duke Energy Carolinas Integrated Resource Plan (IRP) outlines the Company's options and plan for meeting the projected long-term needs. The factors that influence resource needs are:

- Projections of future load growth;
- Available resources from energy efficiency and demand side management;
- Available capacity and energy resources reductions; and
- Ensuring a 17 percent target planning reserve margin over the 20-year horizon.

Duke Energy Carolinas has plans in place to ensure that resources are available and include:

- Execution of Duke's energy efficiency plan which includes a portfolio of demand side management and energy efficiency programs, and continuous on-going collaborative work to develop and implement additional cost-effective energy efficiency and demand side products and services.
    - Currently utilize residential air conditioning direct load control, interruptible service, and standby generation.
- Moving forward with the construction of new plants:

  (1) Combined-cycle/peaking generation:
    - Buck Combined Cycle Project: Construction has begun and the project is scheduled to be operational by the end of 2011.
    - Dan River Combined Cycle Project: Major equipment is being delivered and the site preparation is underway with construction scheduled to begin during the first quarter of 2011. The project is scheduled to be operational by the end of 2012.

  (2) Steam:
    - Construction of the 825 MW Cliffside Unit 6, with the objective of bringing this additional capacity on line by the end of 2012 at the existing Cliffside Steam Station.
    - Continue to investigate the potential switch of fuel from coal to natural gas at the 370 MW Lee Steam Station. Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. For planning purposes, Lee Steam Station will be reflected in the 2010 Duke Energy Carolinas IRP as a retired coal station in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.
- Pursuing nuclear generating options for 2020 timeframe.
- Evaluations of market options for traditional and renewable generation.
- Pursuing wholesale power sales agreements within the Duke Energy Balancing Authority Area

A graphical depiction of the existing generation fleet within Duke Energy Carolinas is provided in Figure 4.1.

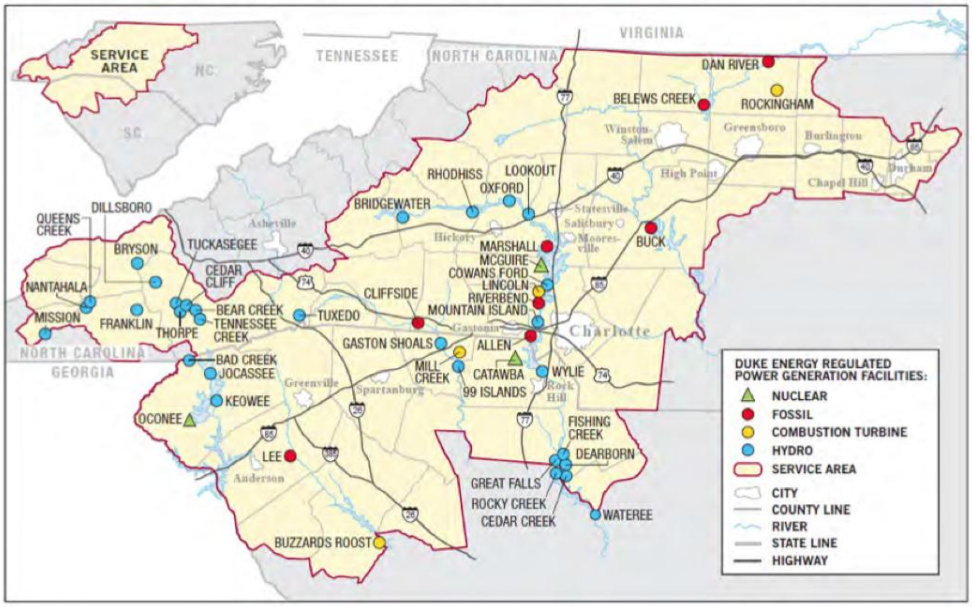

Figure 4.1: DEC Generation Facilities

4.2 DEC Load

The traditional breakdown of load into residential, commercial, and industrial in terms of energy for DEC is shown in Figure 4.2 for 2000 to 2025 as projected in spring of 2010. This forecasted load is based on historical data and the following assumptions:

- The Residential class is expected to have a steady growth of 1.3% over the forecast horizon.
- The Commercial class is projected to grow extremely fast. Offices and education saw the most growth, with retail returning a negative growth.
- The Industrial class has seen significant struggle largely due to Textile closings and the economic downturn. Growth is expected to be strong in rubber & plastics, autos and fabricated metals, other industries such as textiles, furniture and electronics are expected to decline. Overall, Total Industrial sales are expected to grow 0.3% over the forecast horizon.

The load as seen by the DEC for 2008 and 2009 is shown in Figure 4.3. Characteristically, the largest peaks occur in the summer between the end of May and beginning of September. This data has been extrapolated into a load duration curve for evaluation of typical load behavior during the year as shown in Figure 4.4.

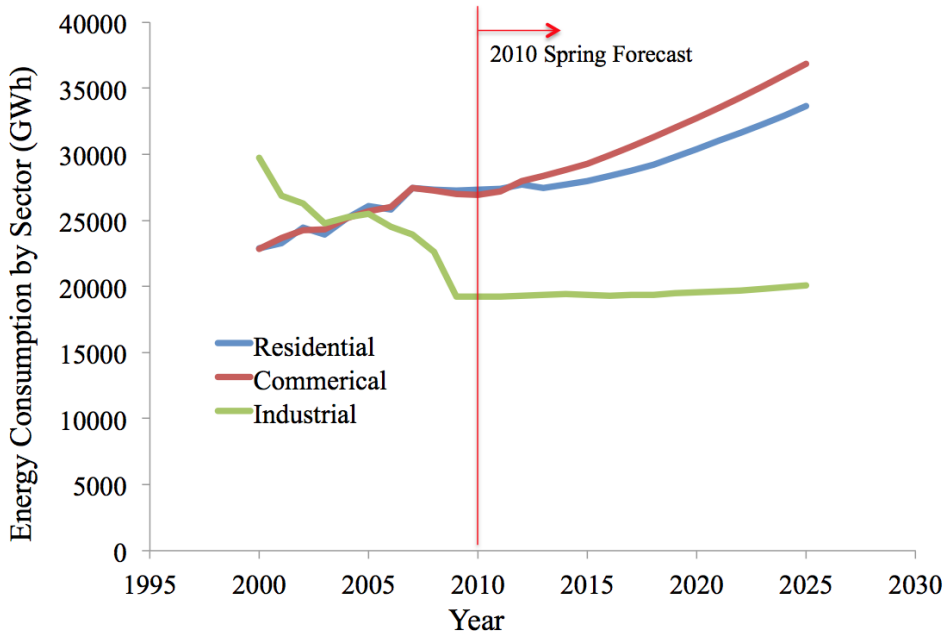

Figure 4.2: Historical and Predicted Energy Consumption for DEC

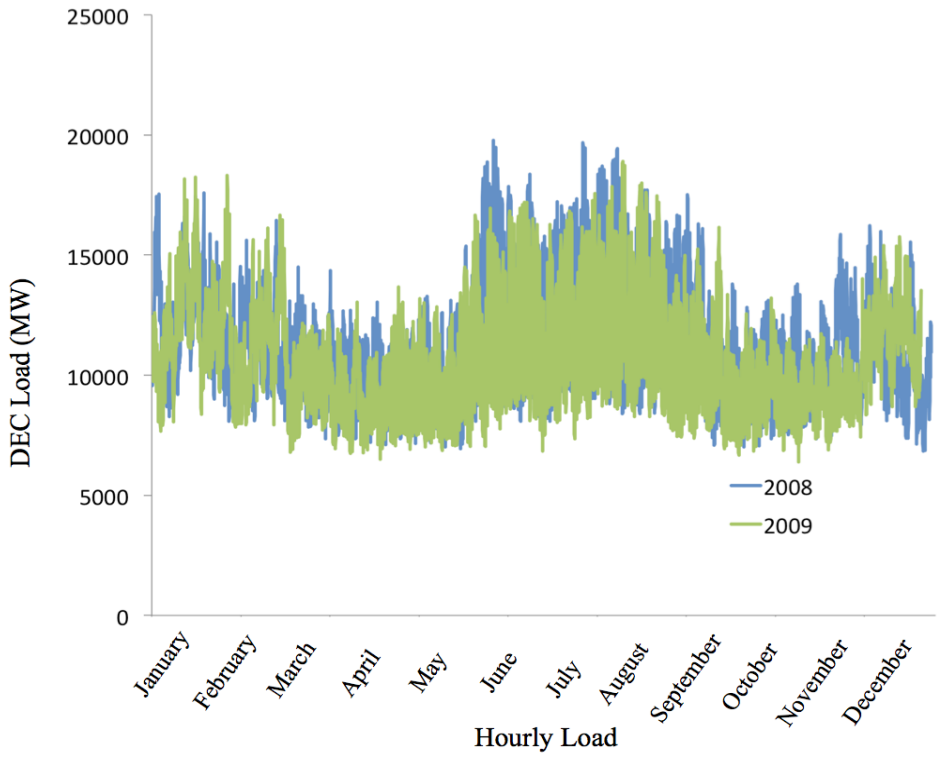

Figure 4.3: DEC load hourly

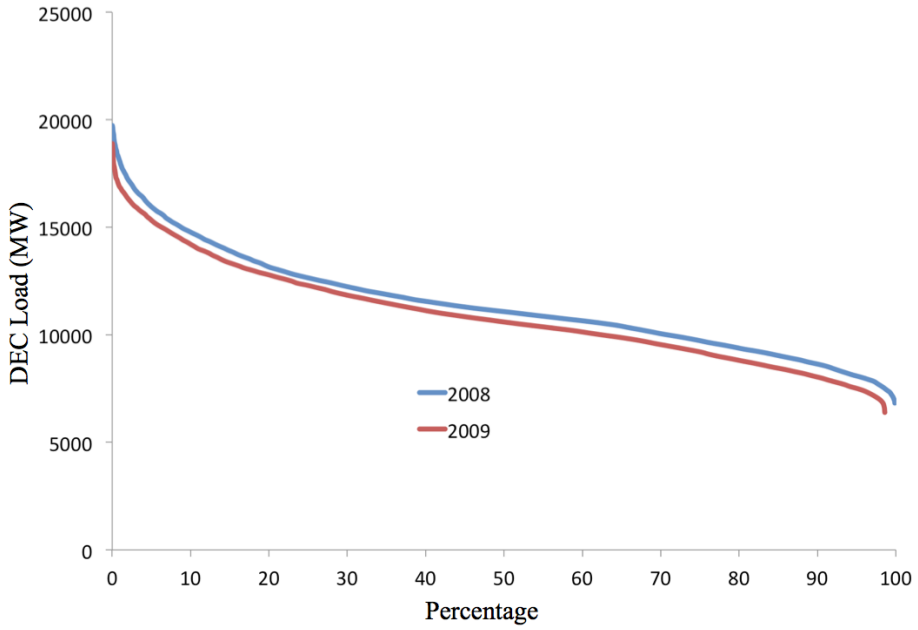

Figure 4.4: Load Duration Curve for DEC

4.3 DEC Transmission Infrastructure and Constraints

The local transmission system near Rhodhiss is composed of 115 kV lines with a number of nearby substations for interconnection to the distribution, as shown in Figure 4.5. The substations are likely indicators that the Rhodhiss facility delivers most of the power to nearby loads as needed. Other nearby higher voltage transmission is rated at 230 kV.

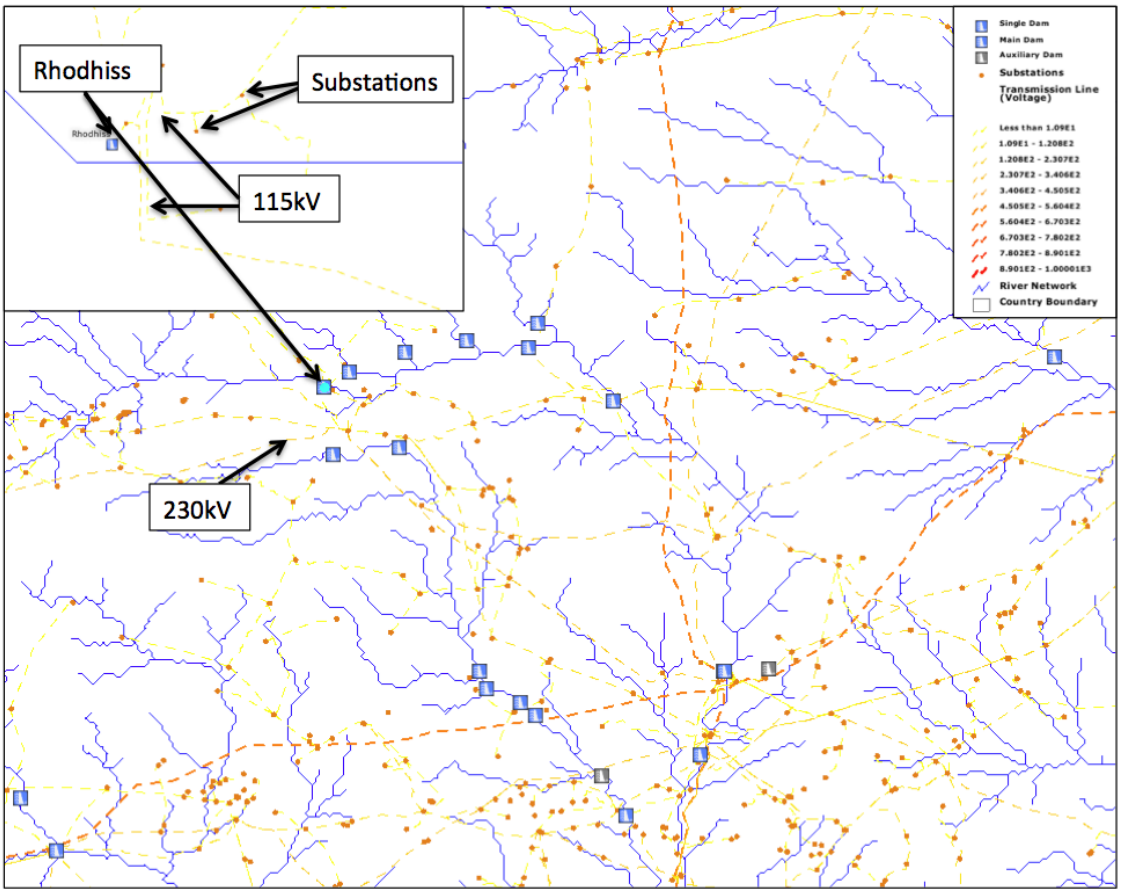

Figure 4.5: Substation and Transmission Infrastructure near Rhodhiss

5.0 Performance Assessment

This chapter provides the discussions and results from the Rhodhiss plant and unit performance analyses, including both hydrology-based and optimization-based performance analyses.

5.1 Hydrology-Based Performance Analyses

The hydrology-based performance analyses include the hydrological background information about the plant site, the discussions of approaches and methods used for hydrology-based assessment, and results for the metrics of Long-Term Stream Power (LTSP), Long-Term Production Potential (LTPP), and Average Power Production (APP). These performance metrics enable benchmarking and trending of performance across many facilities in a variety of river system, power system, and water availability contexts.

5.1.1 Site hydrological characteristics

Rhodhiss hydropower plant is situated on the Catawba River with a contributing watershed of 697,600 acres. Stream flow data from the USGS stream gauge 02140991, located on a tributary (John's River) to the Catawba River, was used to identify the hydrological trends in this watershed area for the period from 2007 through 2011. Other stream gauges on the main river did not have the full record of data for this time period. For the purpose of identifying hydrological variation trends in the area as opposed to absolute values, using a stream gauge in the vicinity of the dam is considered as appropriate. The gauge flow variations are trended (shown as the blue curves in Figure 5.7 and Figure 5.8).

5.1.2 Long-Term Stream Power (LTSP) analysis

The calculation of the annual and Long-Term Stream Power (LTSP) is to determine the power potential at the plant site based on the historical gross heads and flows passing through the site. This total flow (so-called plant site flow or plant flow) includes turbine flows, spill flows, measureable leakages, bypass flows, etc. Ideally, the flows measured immediately downstream of a hydropower plant would be used for this calculation as they would represent the total flows actually passing through the plant site. However, many hydropower plants do not measure the flows, and often there are not any nearby USGS gauge measurements that can be utilized for historic site flows. In this case, the plant operations data would be used to retrieve the historic plant flows.

For the Rhodhiss hydropower plant, the historical records of unit operations with 15 minutes intervals are available, from which the time series of gross heads, the corresponding

powerhouse flows (i.e., the flows passing through all the turbine units for energy generation), as well as the spill flows, can be obtained or retrieved. The sum of powerhouse flow and spill flow is used as plant flow to calculate the stream power potential at the plant site.

5.1.3 Long-Term Production Potential (LTPP) analysis

Since the LTPP is a measure of power production for the three different performance levels of IPL, CPL, and PPL, a series of plant performance curves corresponding to each of these performance levels are needed. The performance curves relating the powerhouse flows to the plant efficiencies are provided by optimization-based plant performance assessment (next section of this Chapter). For the Rhodhiss case, 4 different performance curves under each performance level are provided, corresponding to gross heads of 55 ft, 60 ft, 65 ft, and 70 ft, respectively. These curves serve as the basis from which the values of plant efficiencies corresponding to other gross heads and powerhouse flows are interpolated. The plant efficiency curves are shown in Figures 5.1, 5.2, and 5.3 for the IPL, CPL, and PPL, respectively.

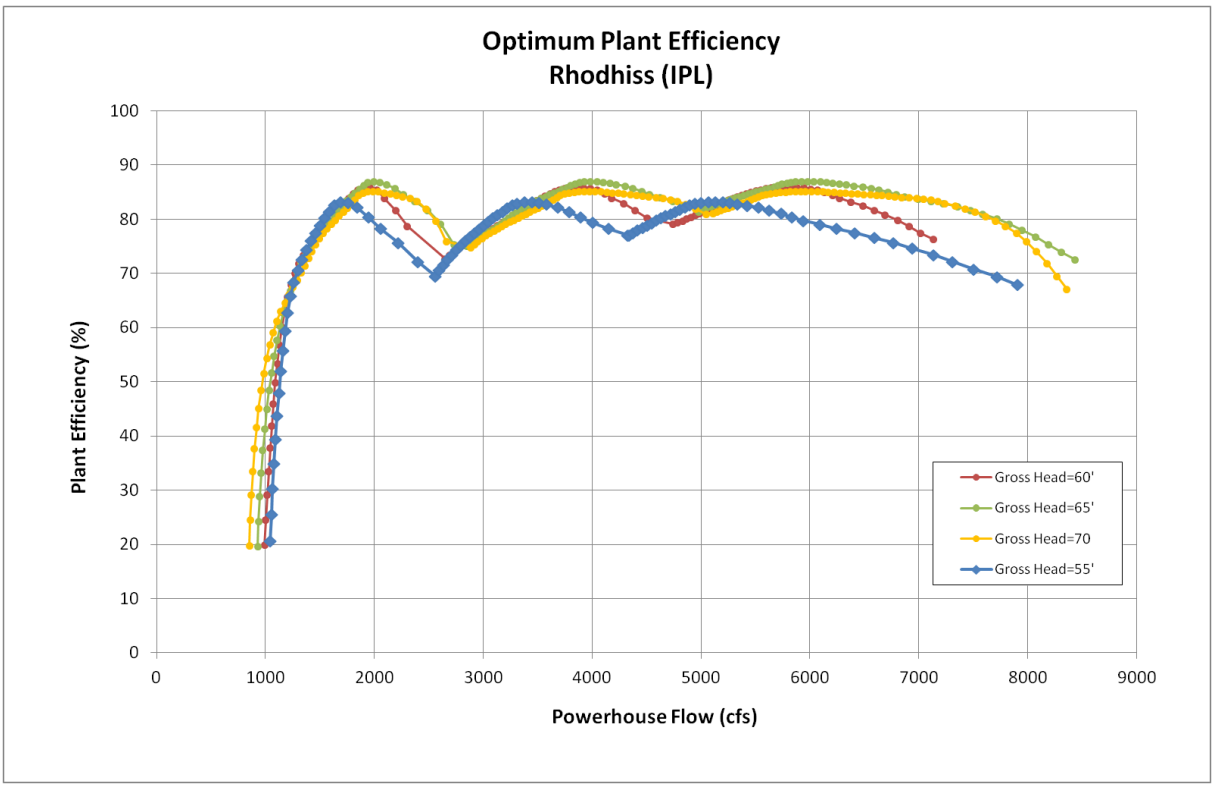

Figure 5.1: Powerhouse Flow versus Plant Efficiency (IPL; Unit 1, Unit 2, Unit 3)

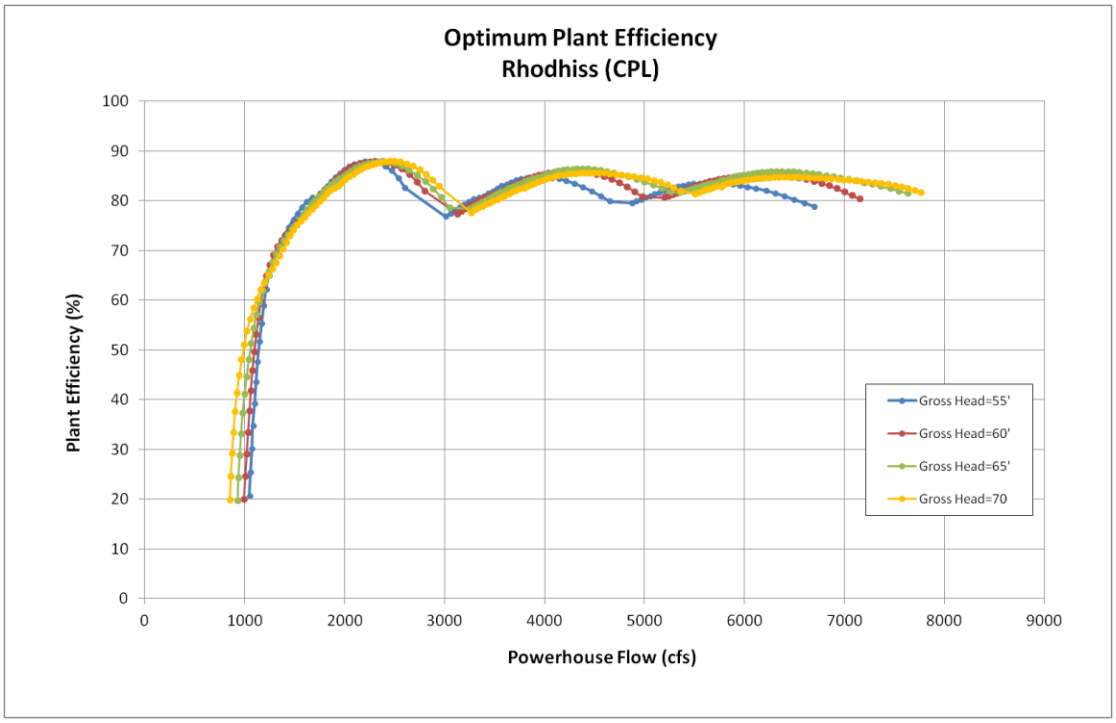

Figure 5.2: Powerhouse Flow versus Plant Efficiency (CPL; Unit 1, Unit 2, Unit 3)

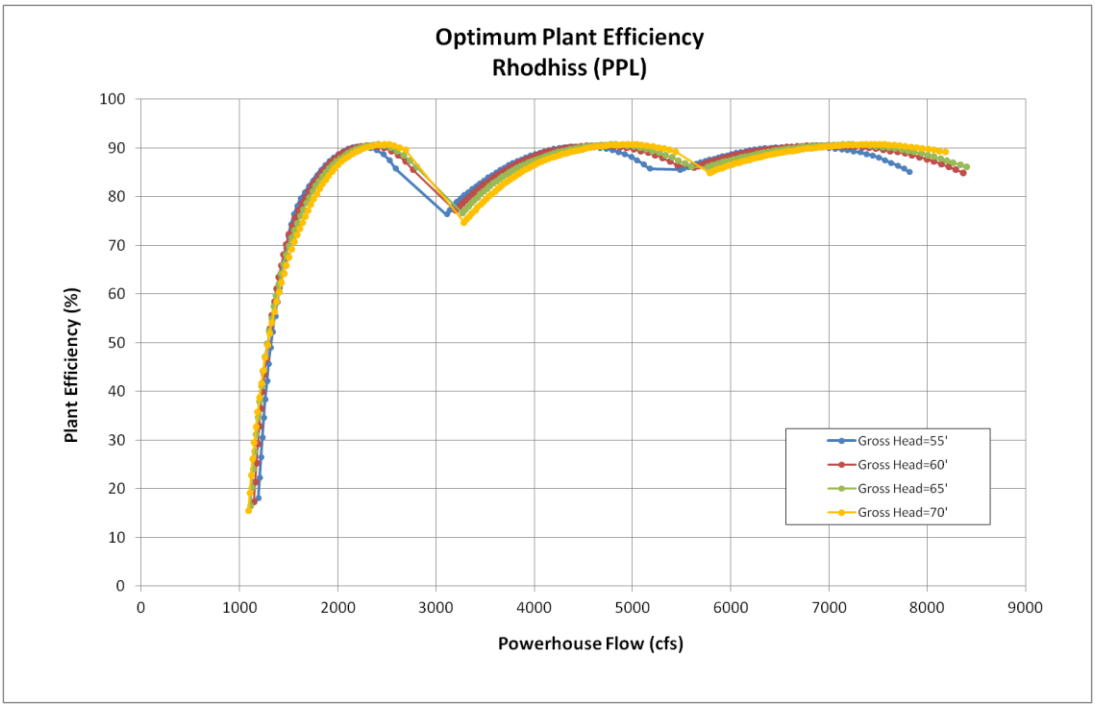

Figure 5.3: Powerhouse Flow versus Plant Efficiency (PPL; Unit 1, Unit 2, Unit 3)

Based on the optimized efficiency curves provided in Figures 5.1 through 5.3, the method used to determine the plant efficiency for a given powerhouse flow assumes that the plant is operated at the peak efficiency point within each of the three curvatures on the optimized efficiency curves for the dispatch of one unit, two units or three units. This is accomplished by "shifting" the actual time increment (15 minutes in this case) of a flow to a shorter or longer time period while conservation of water is maintained by allowing the same volume of water to be released for generating over different time durations with a higher efficiency. This method assumes that the total of the "extra" time resulted from this flow shifting does not exceed what is physically allowable over the course of the day, and hence any net changes of reservoir storage and water levels resulting from this flow shifting are negligible.

For the efficiency curve corresponding to the last unit dispatched (in this case – the third curvature), the powerhouse flows that exceed the peak efficiency point are not shifted to the peak efficiency. Instead, the actual flows and their corresponding efficiencies are used in the calculation of annual and long term production potentials. This reflects a hydropower facility's typical operation during the periods where flows at this large magnitude may represent the passage of a flood. The priority of passing the flood must be considered and the shifting of flows towards smaller ones to gain better efficiency values would not be appropriate in this case.

Historical powerhouse flows that are less than the minimum flow point on the plant efficiency curves are neglected for the calculation of plant production potential. The minimum flow point is associated with the turbine operating limits to avoid turbine vibration and cavitation. In addition, shifting these small flows to those corresponding to the peak efficiencies would result in extremely small and unrealistic periods of run-time. Historical powerhouse flows greater than the maximum value exceeding the endpoint of the plant efficiency curves utilize the endpoint efficiency on the curve.

For the case of Rhodhiss, none of the historical gross head values fall outside of the 55 ft and 70 ft envelope of gross heads.

5.1.4 Average Power Production (APP) calculation

The calculation of the Average Power Production (APP) simply requires the time-series of historical generation data. For the Rhodhiss data, only positive values of reported generation are used in this computation. Generation values of zero within the time-series are also included in the average.

5.1.5 Results from hydrology-based performance analyses

The actual productions in megawatt-hours (MWh), in addition to the average hourly MW for each of the years, are calculated. Table 5.1 summarizes the annual generations (in MWh) for each year from 2007 to 2011, respectively, for the historical recorded generations, plant production potentials at IPL, CPL and PPL, and the stream hydropower potentials.

Table 5.2 summarizes the annual power potentials (in MW) for each year from 2007 to 2011, respectively, for historical recorded productions, plant production potentials at IPL, CPL and PPL and the stream hydropower potentials. The bottom array shows the long-term power potentials (in MW) over the years from 2007 to 2011.

Table 5.3 summarizes the absolute and relative increases in annual generations (MWh) at each of the IPL, CPL, and PPL levels, potentially gained from optimization of plant operations.

Table 5.1: Summary of Results for Annual Generation

	Actual Annual Generation	Optimized Annual Generation (IPL)	Optimized Annual Generation (CPL)	Optimized Annual Generation (PPL)	Annual Stream Power Potential
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2007	32,866	34,067	34,573	36,315	40,650
2008	35,398	36,507	36,651	38,685	42,821
2009	67,517	69,896	70,442	74,446	83,232
2010	63,360	65,921	66,923	70,212	78,270
2011	29,768	30,695	31,063	32,515	36,799

Notes:

1. The 2007 results include generation and flow from January 1, 2007, through June 30, 2007, only.
2. The 2011 results include generation and flow from January 1, 2011, through August 31, 2011, only.
3. Some missing hours were found on the first and last day for the year 2008 and 2011. These values account for less than 0.25% of the entire yearly data.

Table 5.2: Summary of Results for APP, LTPP and LTSP

	APP	LTPP IPL	LTPP CPL	LTPP PPL	LTSP
	(MW)	(MW)	(MW)	(MW)	(MW)
2007	7.57	7.85	7.96	8.37	9.36
2008	4.04	4.16	4.18	4.41	4.89
2009	7.72	7.99	8.05	8.51	9.51
2010	7.24	7.53	7.65	8.03	8.95
2011	5.31	5.48	5.54	5.80	6.57
All Years	6.32	6.55	6.62	6.97	7.78

Notes:

1. The 2007 results include generation and flow from January 1, 2007, through June 30, 2007, only.
2. The 2011 results include generation and flow from January 1, 2011, through August 31, 2011.
3. Some missing hours were found on the first and last day for the year 2008 and 2011. These values account for less than 0.25% of the entire yearly data.

Table 5.3: Summary of Generation Increases for Optimized IPL, CPL, and PPL Performance Levels

	Improvement (IPL)	Improvement (CPL)	Improvement (PPL)	Improvement (IPL)	Improvement (CPL)	Improvement (PPL)
	(MWh)	(MWh)	(MWh)	(%)	(%)	(%)
2007	1,201	1,707	3,449	3.65	5.19	10.49
2008	1,109	1,253	3,287	3.13	3.54	9.29
2009	2,379	2,925	6,929	3.52	4.33	10.26
2010	2,561	3,563	6,852	4.04	5.62	10.81
2011	927	1,295	2,740	3.11	4.35	9.20

The monthly averaged actual power production (APP), plant production potential, and stream power potential are plotted in Figures 5.4, 5.5 and 5.6, respectively. These monthly variation trends can be compared across the years from 2007 to 2011, which shows the overall production and power potential were the lowest in 2008 and the highest in 2009, the same finding as indicated in Table 5.2. As expected, the APP calculated from historical generation records (Figure 5.4) trended consistently with the stream power potential that is calculated from the plant site flows (Figure 5.6). This is because at the Rhodhiss site there was little spill and no releases other than for power generation purposes. Also as expected, the monthly variations of plant production potential for each year (Figure 5.5) follow the similar pattern and trend of stream power potential (Figure 5.6). The major difference between the two plots is that plant production potential takes the plant efficiency into account.

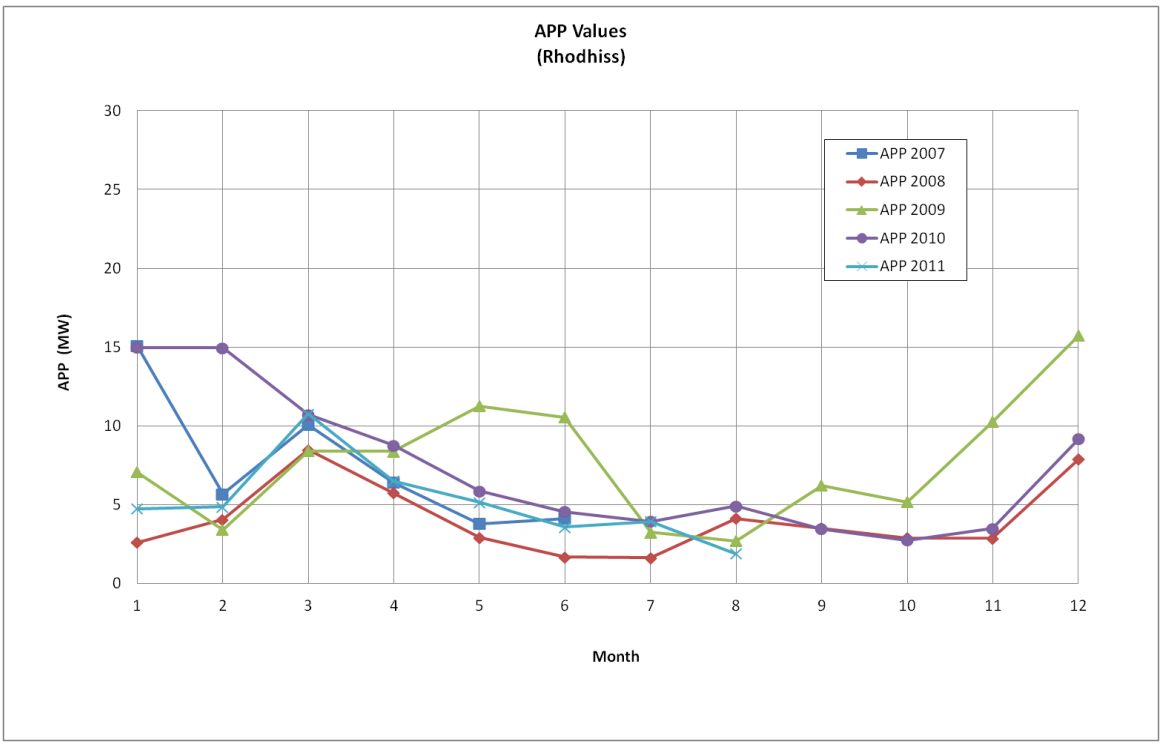

Figure 5.4: Monthly averaged APP trend for 2007-2011

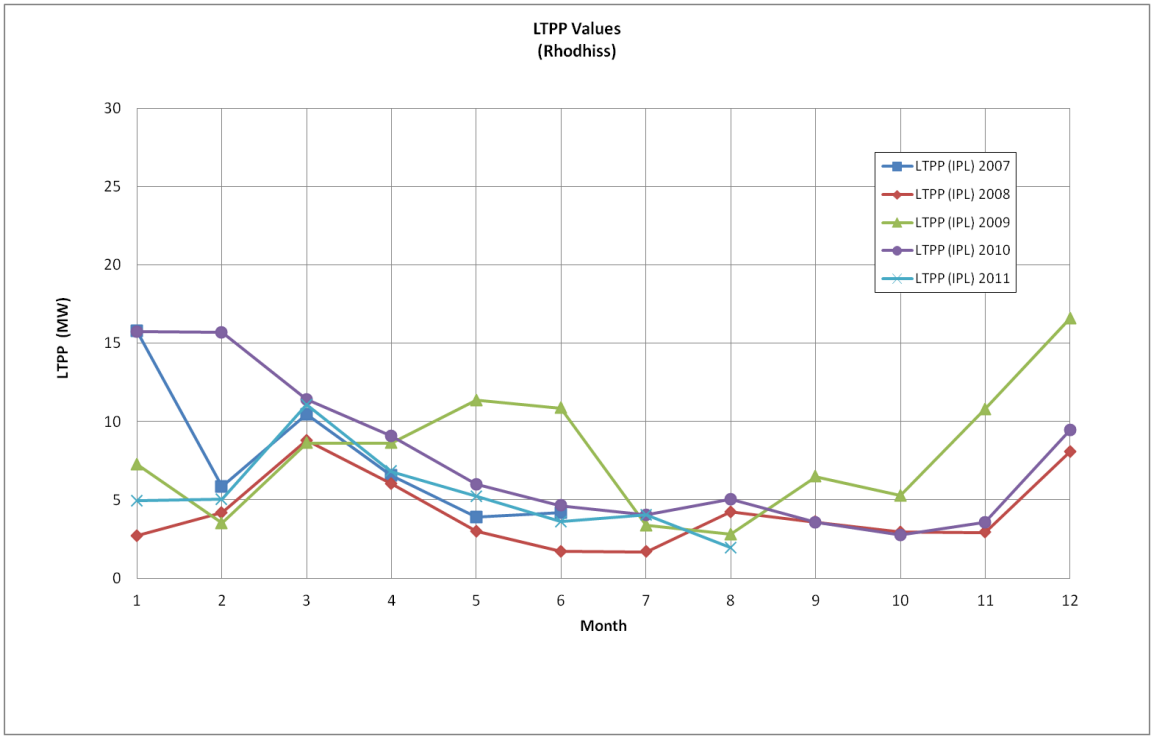

Figure 5.5: Monthly averaged plant production potential trend for 2007-2011

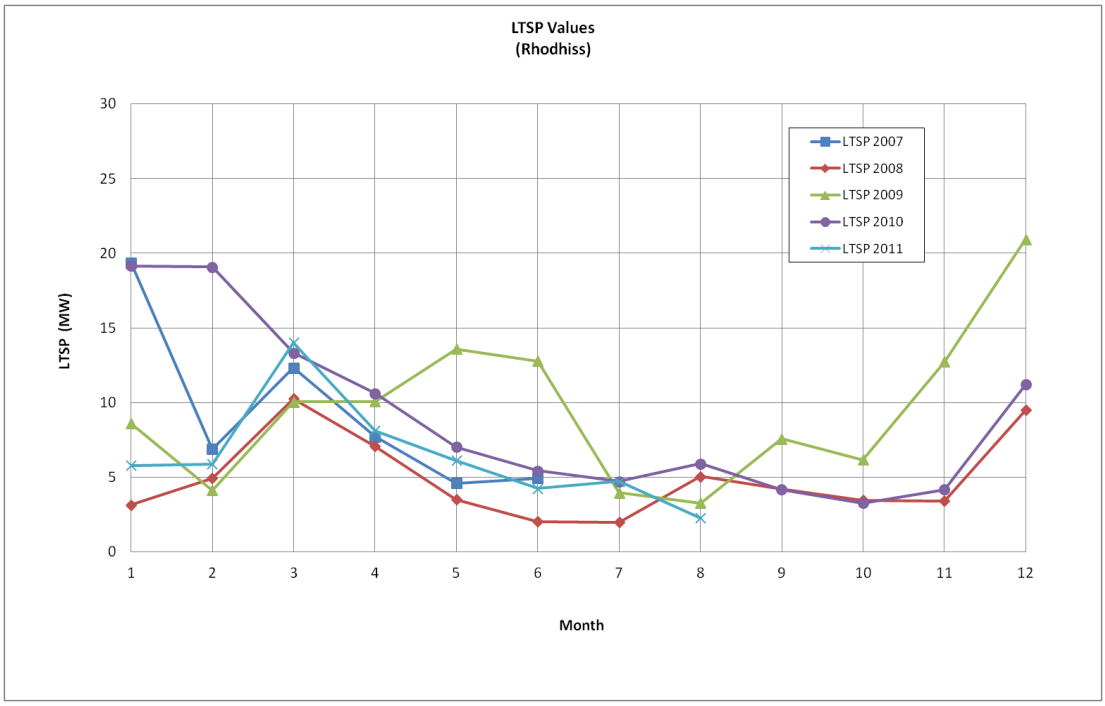

Figure 5.6: Monthly averaged stream power potential trend for 2007-2011

The increasing trend in the results for the annual optimized generation in Table 5.1 from IPL to CPL and to PPL is as expected. This is also reflected in the LTPP values in Table 5.2. An indication that the plant was not operated at an optimized schedule is reflected in the comparatively smaller values for the actual annual generation as compared to the optimized annual generation. Optimized generation for all of the years indicate an average performance increase over actual generation of about 3.5%, 4.6%, and 10.0%, at the IPL, CPL, and PPL levels, respectively. This corresponds to average increase in annual generation by about 1635 MWh, 2149 MWh, and 4651 MWh for the five year period at each of the respective performance levels.

Figure 5.7 depicts and compares the trends of monthly average stream flows and monthly average plant production potential at IPL, CPL and PPL. Because the majority of the stream flow passing Rhodhiss is used for power generation, the variation of plant production potential over time trended consistently with the hydrological variation in the vicinity. This comparison also helps to identify significant periods of plant outage or periods for which plant operations data are missing (e.g., July-Dec. 2007). In addition, the variation of yearly average stream flows, as shown in Figure 5.8, clearly explains why the annual power potentials for the years of

2008 and 2011 are significantly lower than those of 2007, 2009 and 2010 (see in Table 5.2). Observation of the yearly average stream flows indicates that 2008 and 2011 are “dry” years, while the 2009 is a “wet” year which provides a power potential 92% higher than that of 2008 and 46% higher than that of 2011.

Corresponding to the highest peak of hydrological flow (see the blue curve in Figure 5.7) for the period from April to July in 2009, the significantly higher actual production is observed for the same period in Figure 5.4. The second highest hydrological peak in Figure 5.7 for the period from Nov. 2009 to May 2010 also corresponds to the relatively higher production in Figure 5.4.

Some of the turbine flow data extracted from the time-condensed data files provided by the plant owner appear erroneous (e.g., some reported generation values exceed what is possible to achieve by the reported flows, and in some instances non-zero generation amount is reported during periods of zero flow). Thus, the turbine flows used for these hydrological analyses are based on the reported plant generations.

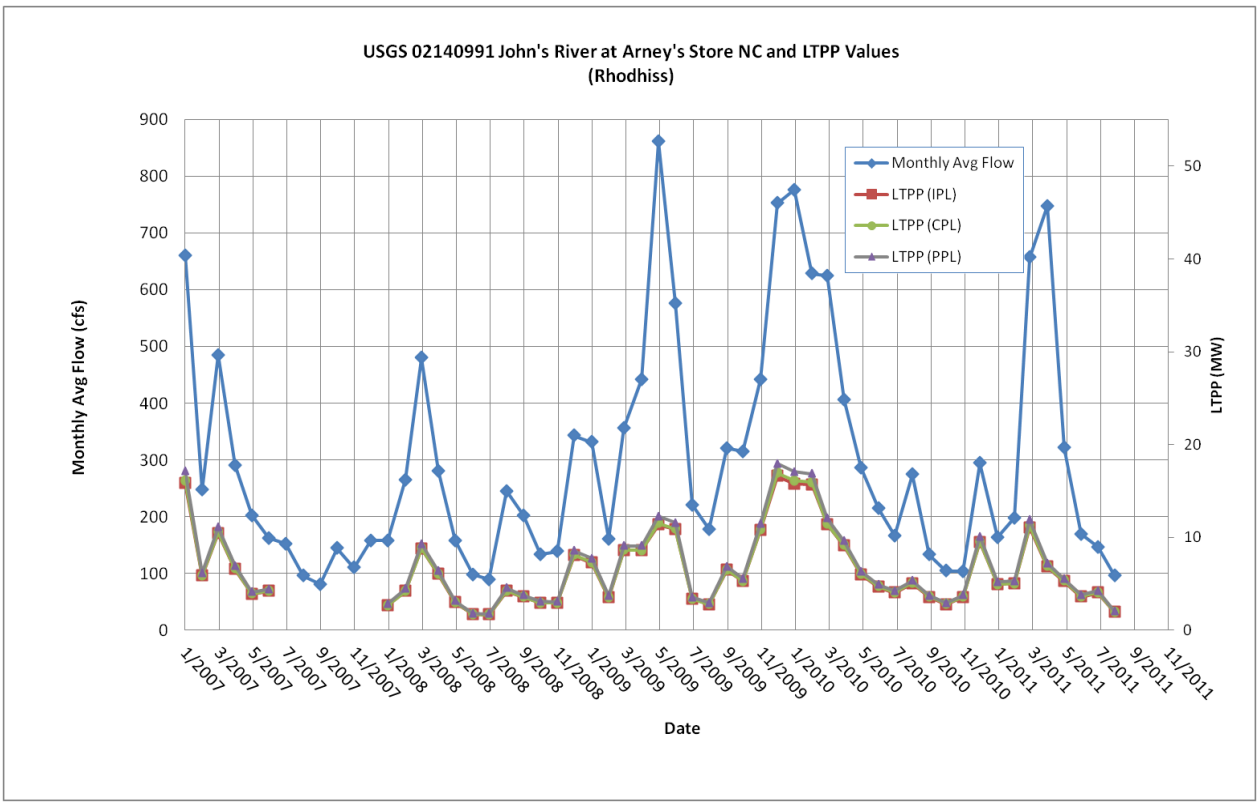

Figure 5.7: Monthly average flow and plant production potential trend for 2007-2011

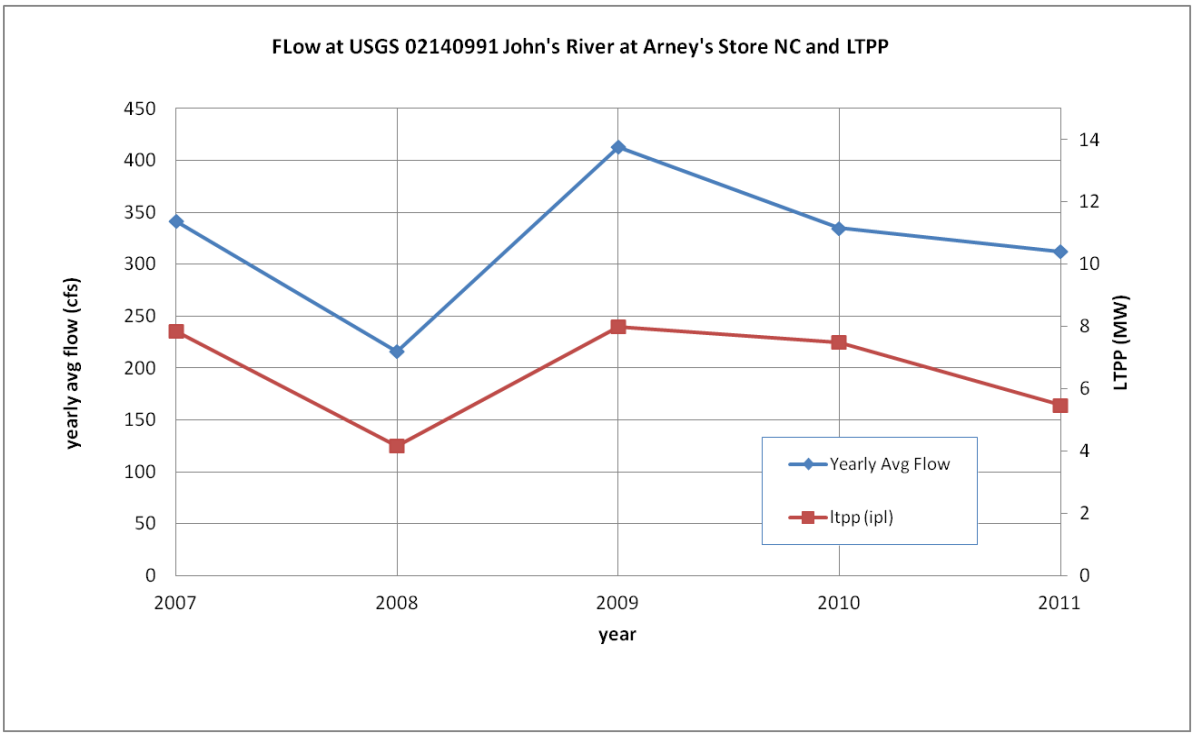

Figure 5.8: Yearly average flow and LTPP trend for 2007-2011

5.2 Optimization-Based Performance Analyses

5.2.1 Unit and plant performance curves

The Initial Performance Level (IPL) unit performance curves are based on turbine net head efficiency data from S. Morgan Smith Company dated July 9, 1930, generator efficiency data from Westinghouse Electric & Manufacturing Company dated February 28, 1927, and intake/penstock head loss information from American Hydro's response to Specification 00003.03.0112.00-F14-001. The derived IPL unit flow versus unit power curves at gross heads of 55 ft, 60 ft, 65 ft, and 70 ft are presented in Figure 5.9, and the corresponding gross head unit efficiencies versus power are provided in Figure 5.10.

The Current Performance Level (CPL) unit performance curves for Unit 1 and Unit 3 are based on the IPL curves, with an additional assumed degradation (i.e., a net head turbine efficiency loss) of 2.5%. The derived CPL unit flow versus unit power curves for Unit 1 and Unit 3 at gross heads of 55 ft, 60 ft, 65 ft, and 70 ft are presented in Figure 5.11, and the corresponding gross head unit efficiencies versus power for Unit 1 and Unit 3 are provided in Figure 5.12. The Current Performance Level (CPL) unit performance curves for Unit 2 are based on the IPL

generator curve and the net head turbine efficiency curves provided by the turbine manufacturer, American Hydro Corporation, at the time of the runner upgrade and included in American Hydro's response to Specification 00003.03.0112.00-F14-001. The CPL unit flow versus unit power curves for Unit 2 at gross heads of 55 ft, 60 ft, 65 ft, and 70 ft are presented in Figure 5.12, and the corresponding gross head unit efficiencies versus power for Unit 2 are provided in Figure 5.13.

The Potential Performance Level (PPL) unit performance curves for Unit 1, Unit 2, and Unit 3 are based on the CPL curve for the upgraded Unit 2, with an additional assumed net head turbine efficiency improvement of 1% due to improved turbine technology and a maximum assumed generator efficiency of 98% due to improved generator technology. The PPL unit flow versus unit power curves for Unit 1, Unit 2, and Unit 3 at gross heads of 55 ft, 60 ft, 65 ft, and 70 ft are presented in Figure 5.14, and the corresponding gross head unit efficiencies versus power for Unit 1, Unit 2, and Unit 3 are provided in Figure 5.15.

Based on the IPL, CPL, and PPL unit performance curves, the optimization engine (see Manual Appendix 2.03) was used to compute optimized plant gross head efficiencies. The IPL, CPL, and PPL optimized plant gross head efficiencies versus plant power at gross heads of 55 ft, 60 ft, 65 ft, and 70 ft are presented in Figures 5.16 through 5.18, respectively. Figure 5.19 shows the distribution of yearly generation with gross head for 2007 through 2011. Typically, 90% or more of the plant's generation occurs at a gross head of 60 ft. Figure 5.20 compares optimized plant gross head efficiency versus plant power for IPL, CPL, and PPL at a gross head of 60 ft.

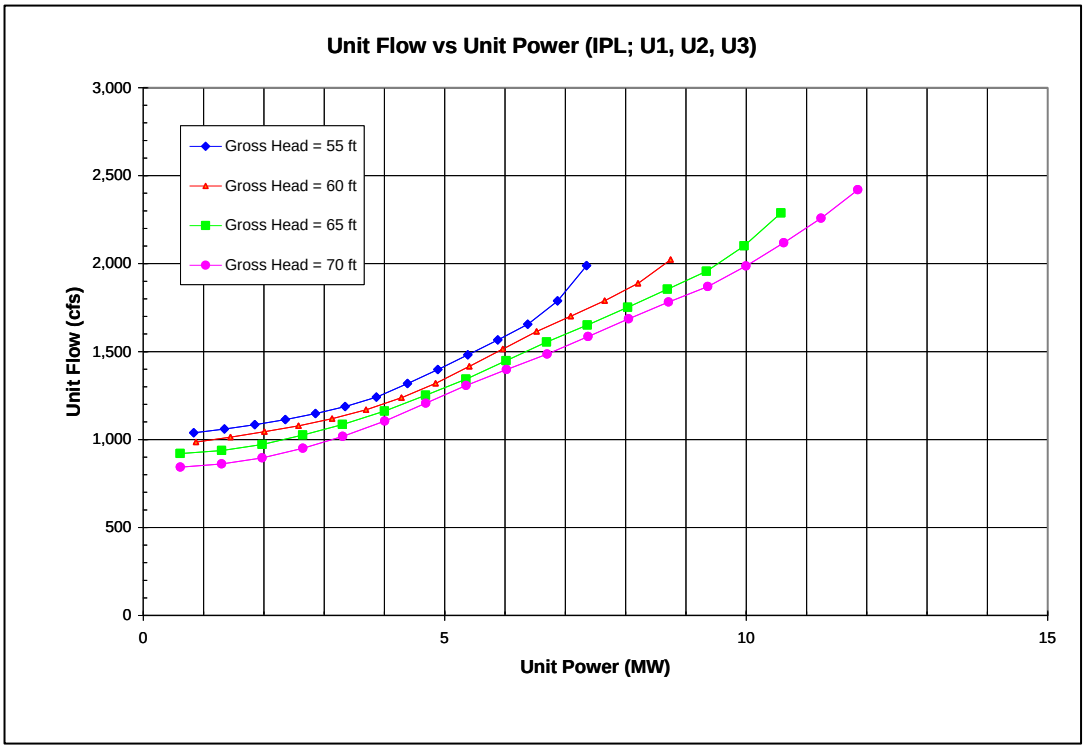

Figure 5.9: Unit Flow versus Unit Power (IPL; Unit 1, Unit 2, Unit 3)

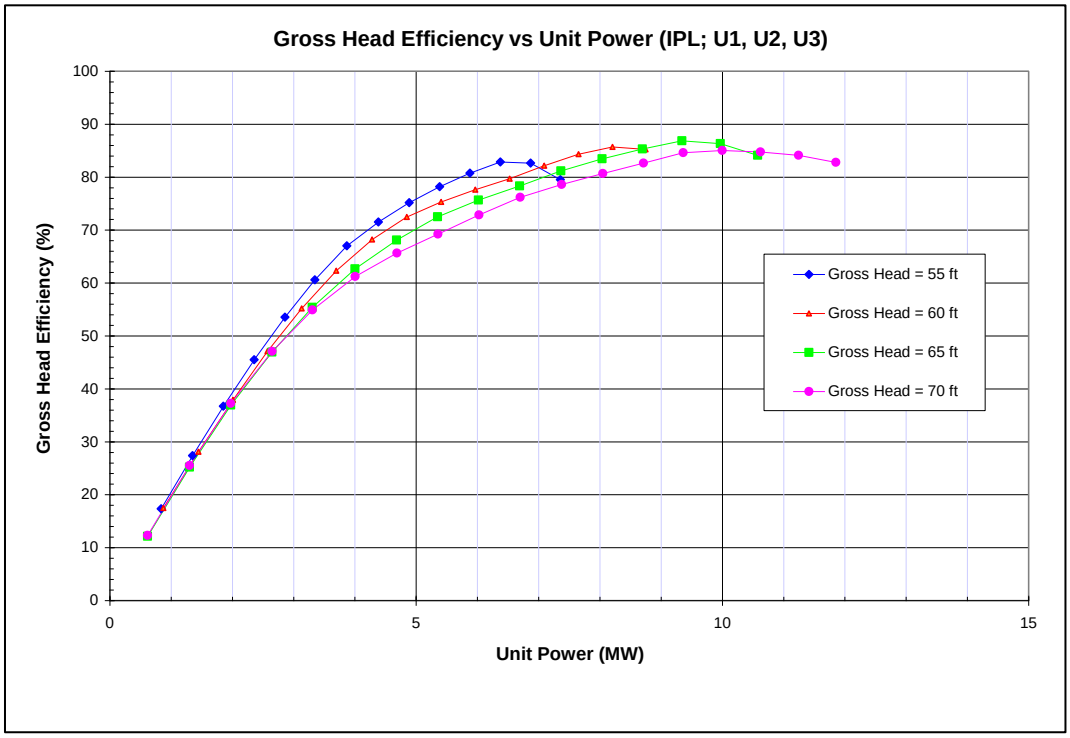

Figure 5.10: Unit Gross Head Efficiency versus Unit Power (IPL; Unit 1, Unit 2, Unit 3)

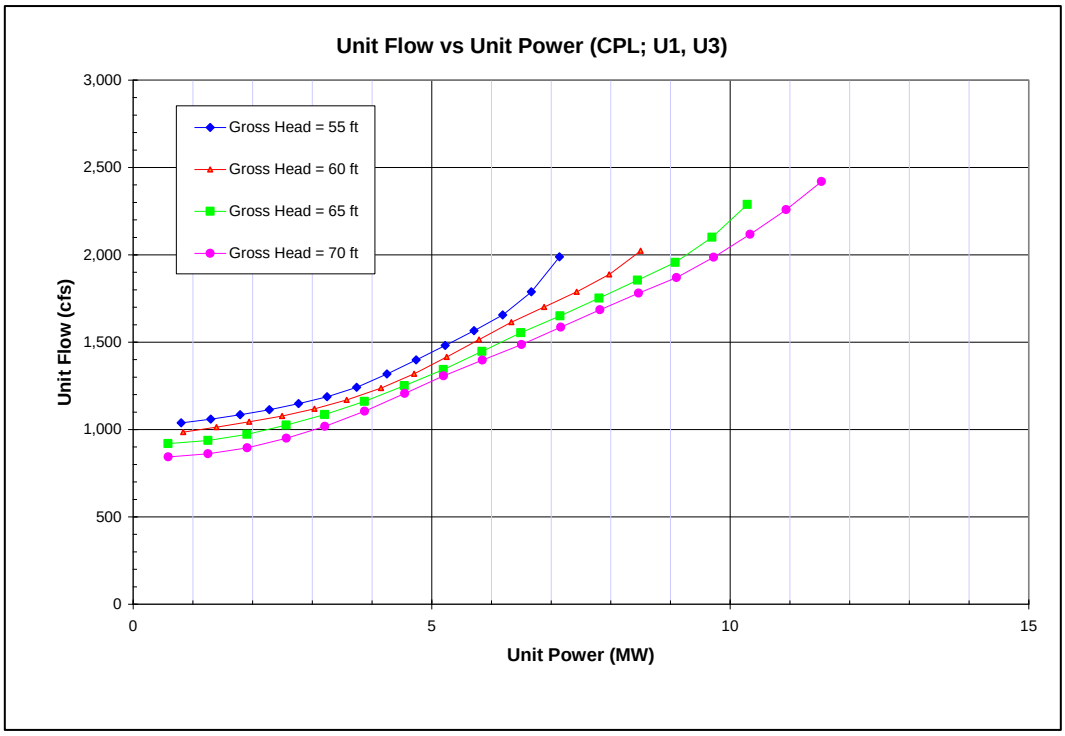

Figure 5.11: Unit Flow versus Unit Power (CPL; Unit 1, Unit 3)

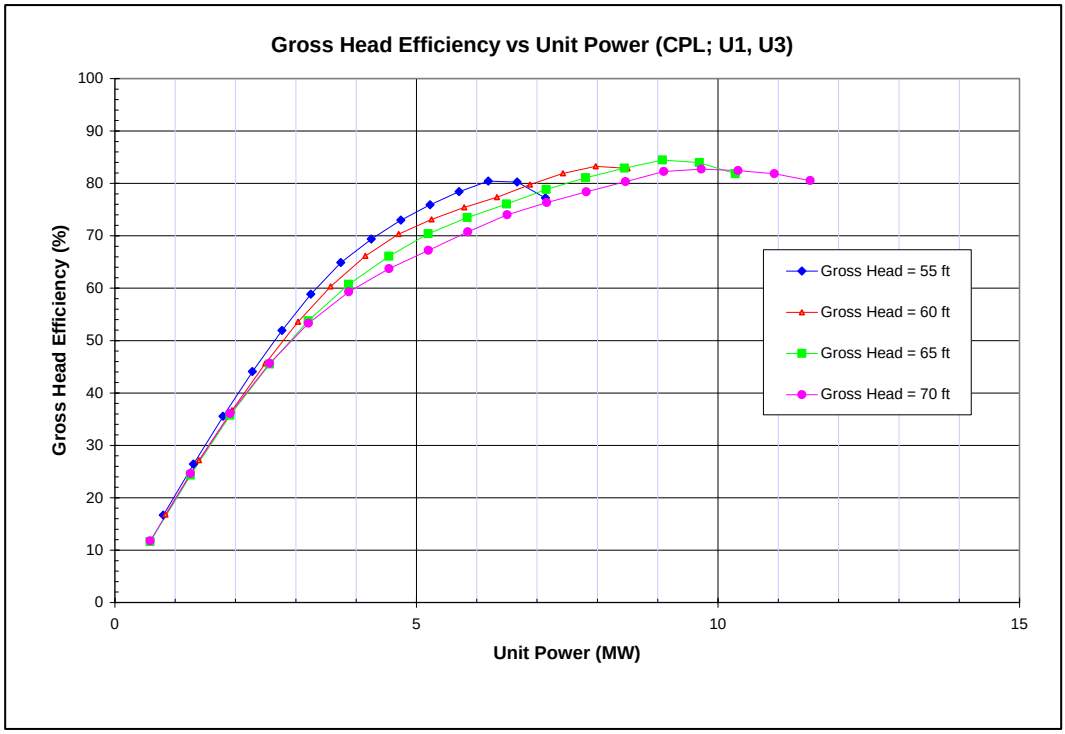

Figure 5.12: Unit Gross Head Efficiency versus Unit Power (CPL; Unit 1, Unit 3)

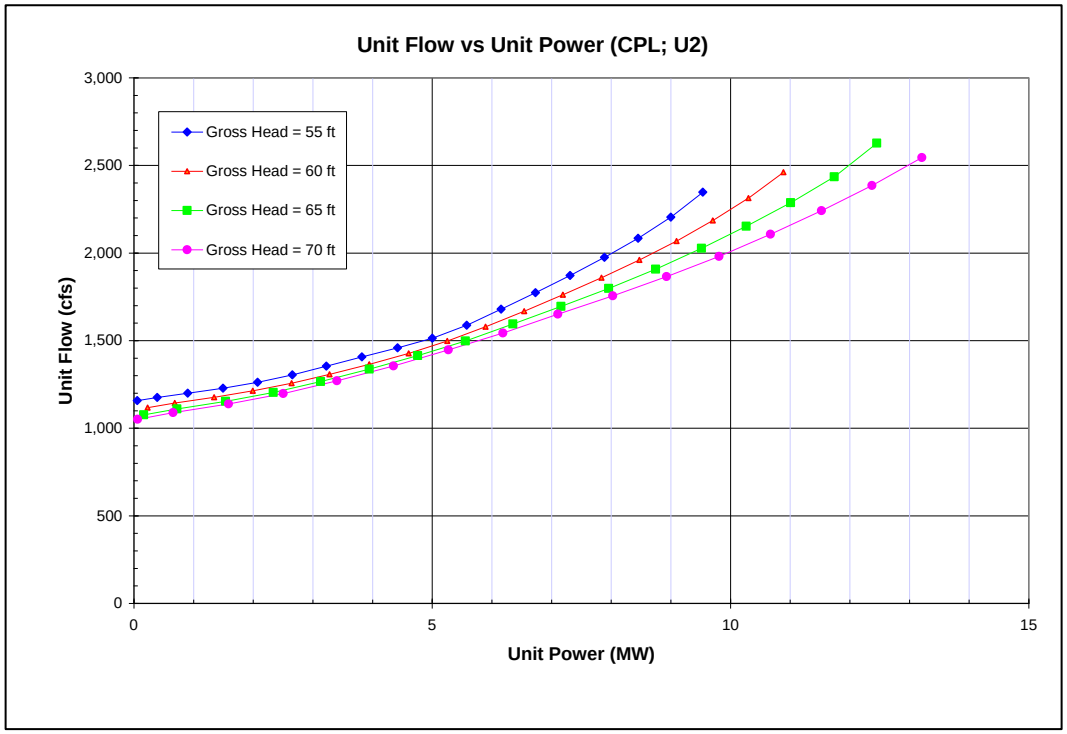

Figure 5.13: Unit Flow versus Unit Power (CPL; Unit 2)

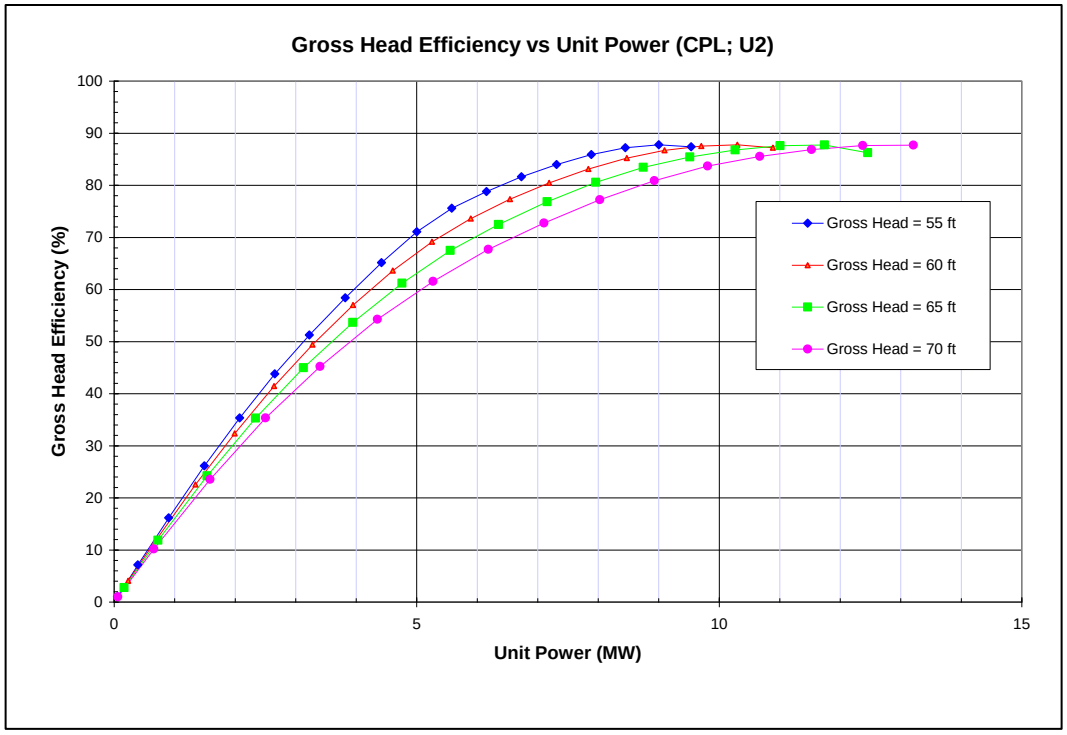

Figure 5.14: Unit Gross Head Efficiency versus Unit Power (CPL; Unit 2)

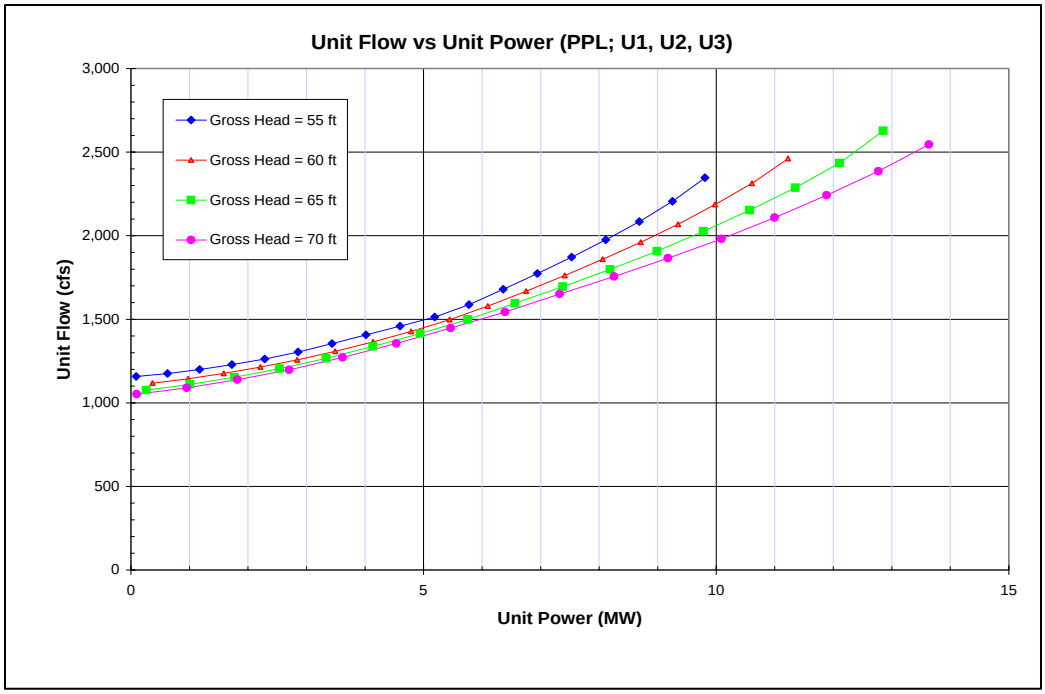

Figure 5.15: Unit Flow versus Unit Power (PPL; Unit 1, Unit 2, Unit 3)

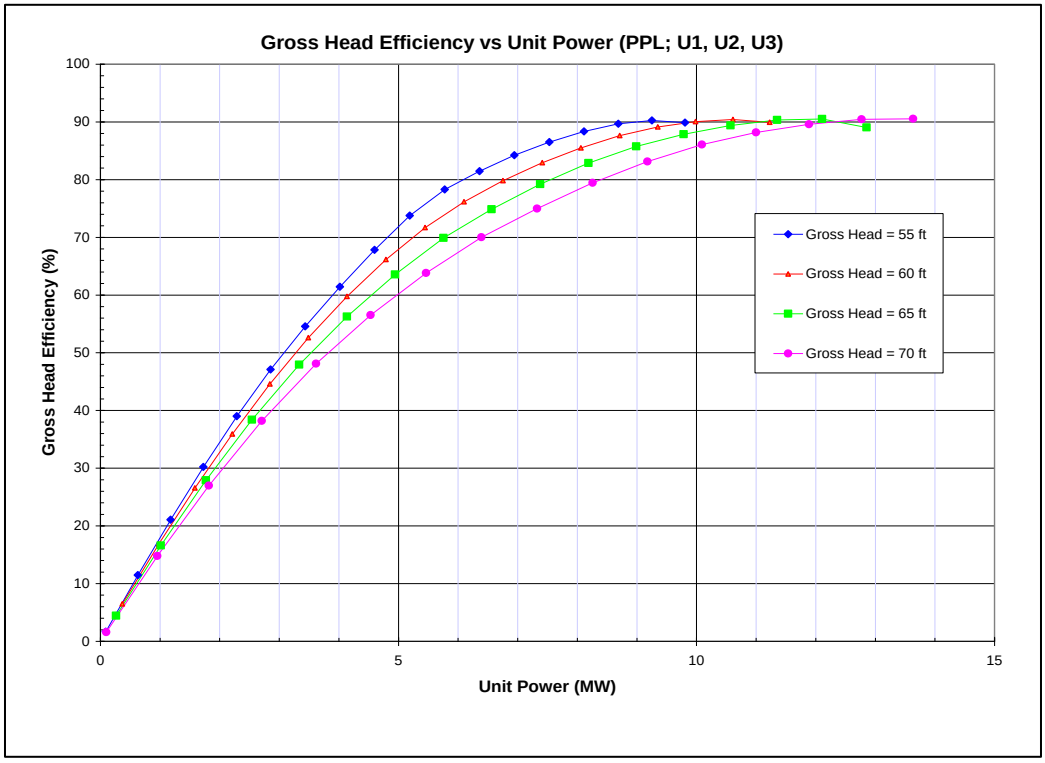

Figure 5.16: Unit Gross Head Efficiency versus Unit Power (PPL; Unit 1, Unit 2, Unit 3)

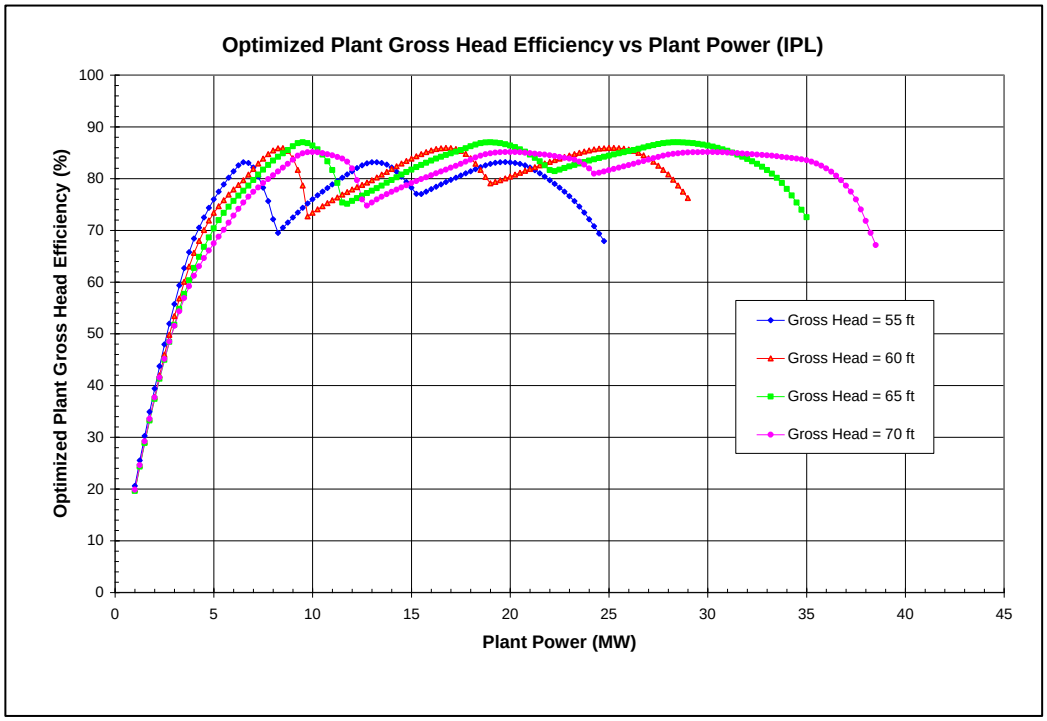

Figure 5.17: Optimized Plant Gross Head Efficiency versus Plant Power (IPL)

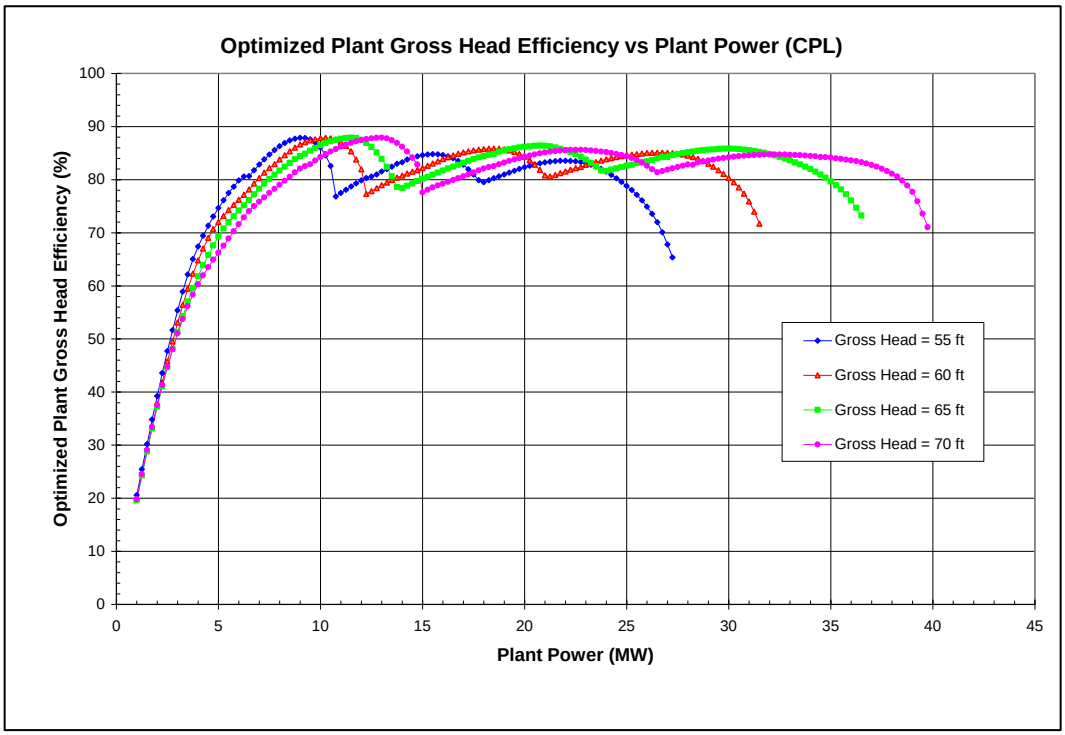

Figure 5.18: Optimized Plant Gross Head Efficiency versus Plant Power (CPL)

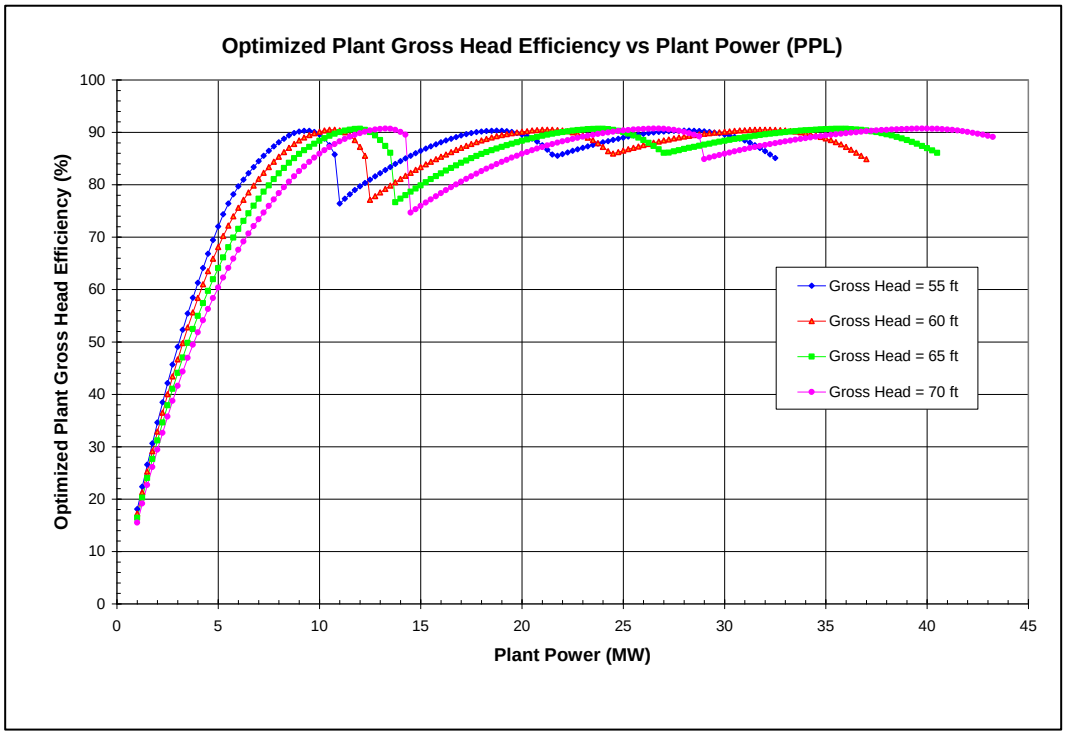

Figure 5.19: Optimized Plant Gross Head Efficiency versus Plant Power (PPL)

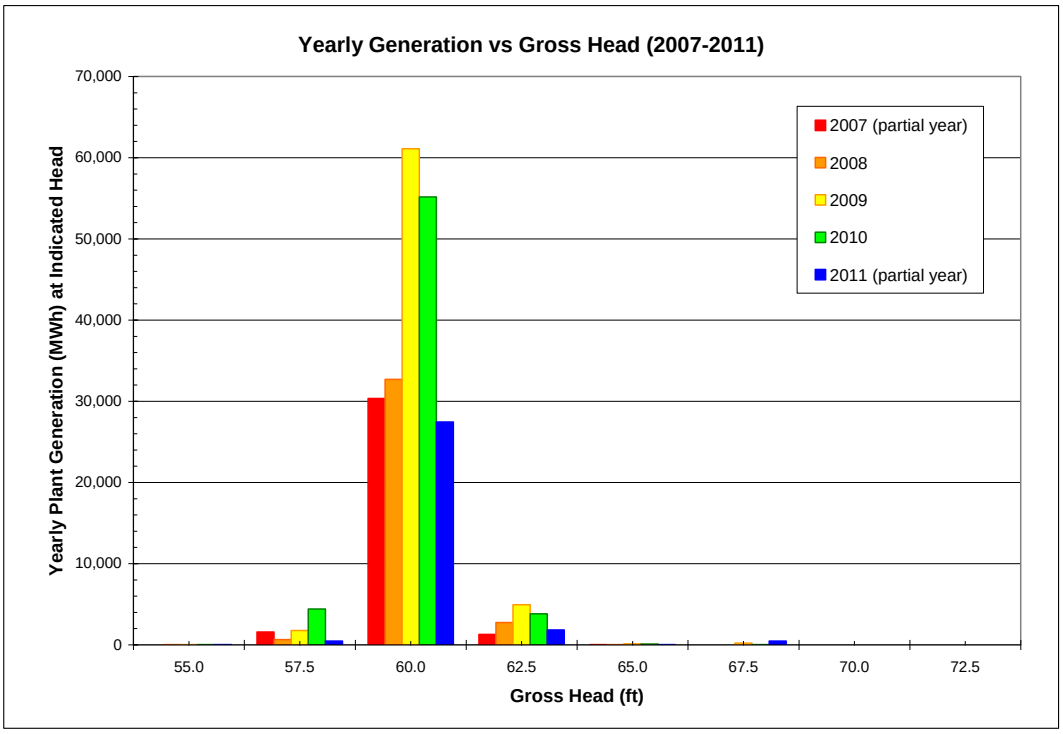

Figure 5.20: Distribution of Yearly Generation with Gross Head (2007 – 2011)

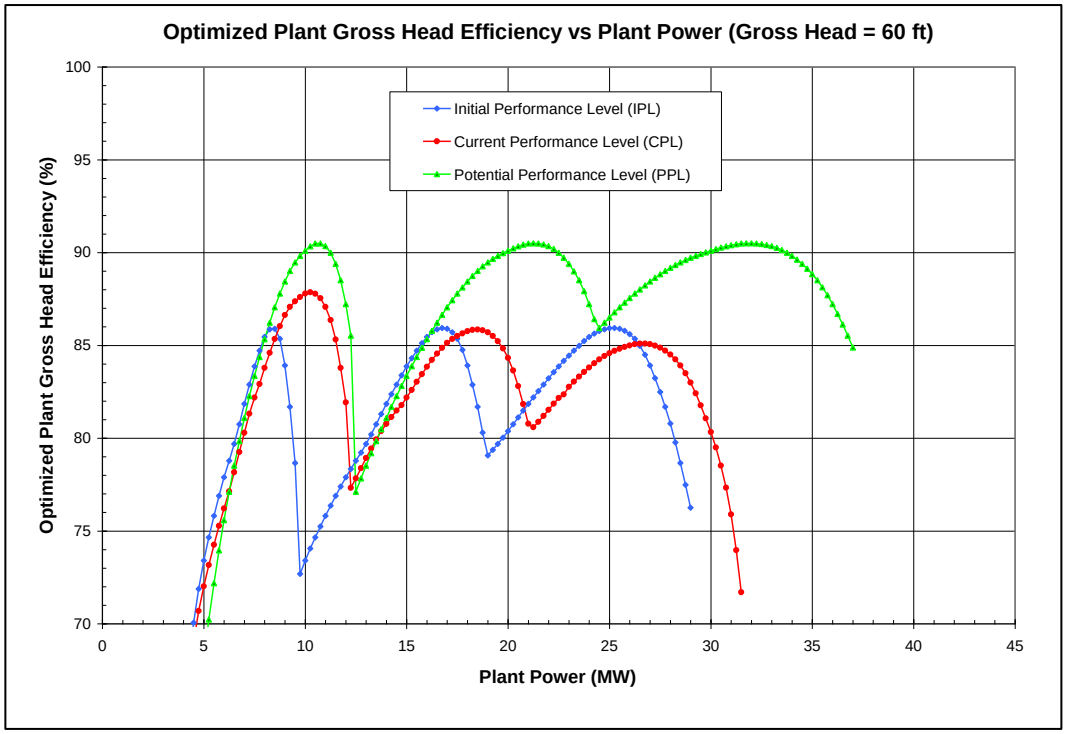

Figure 5.21: Optimized Plant Gross Head Efficiency versus Plant Power (GH = 60 ft)

5.2.2 Operation efficiency analyses

The Operation Efficiency Analyses use unit efficiency characteristics and archival operations data to determine how closely the actual dispatch matches the optimized dispatch. Computational steps for determining the operation efficiency are discussed in the Performance Assessment Manual. At each time step of the archival data, the optimized plant efficiency is computed, apportioning the total plant load among the available units to maximize the plant efficiency while meeting the necessary constraints (e.g., matching the actual plant load, matching the head, and operating each unit within minimum and maximum power limits). Energy gains due to water savings from optimized dispatch are computed by assuming that the water is converted into energy at the optimized plant efficiency and head for the time step in which the potential energy gain occurs.

Results from the operation efficiency analyses are summarized in Table 5.4. Potential efficiency improvements due to improved optimization range from a low of 1.5% for 2008 to a high of 3.0% for 2010, with an average of 2.3%.

Table 5.4 Summary of Results from Operation Efficiency Analyses

Year	Improvement (MWh)	Improvement (%)
2007	1,074	2.6
2008	633	1.5
2009	1,542	2.1
2010	2,027	3.0
2011	757	2.3

Notes:
1. The 2007 results only include generation from January 1, 2007, through June 30, 2007.
2. The 2011 results only include generation from January 1, 2011, through August 22, 2011.
3. Operation efficiency results show potential improvements while continuously meeting the actual generation.
4. Aeration effects are not included in the operation efficiency analyses.

Typical results from the operation efficiency analyses are provided in Figures 5.22 through 5.25. In these figures, the red line represents the actual Unit 1 generation, the blue line represents the actual Unit 2 generation, and the violet line represents the actual Unit 3 generation. The dotted red line represents the optimized Unit 1 generation, the dotted blue line represents the optimized Unit 2 generation, and the dotted violet line represents the optimized Unit 3 generation. In addition, the green line refers to the secondary axis on the right and represents the potential plant efficiency improvement due to optimized generation.

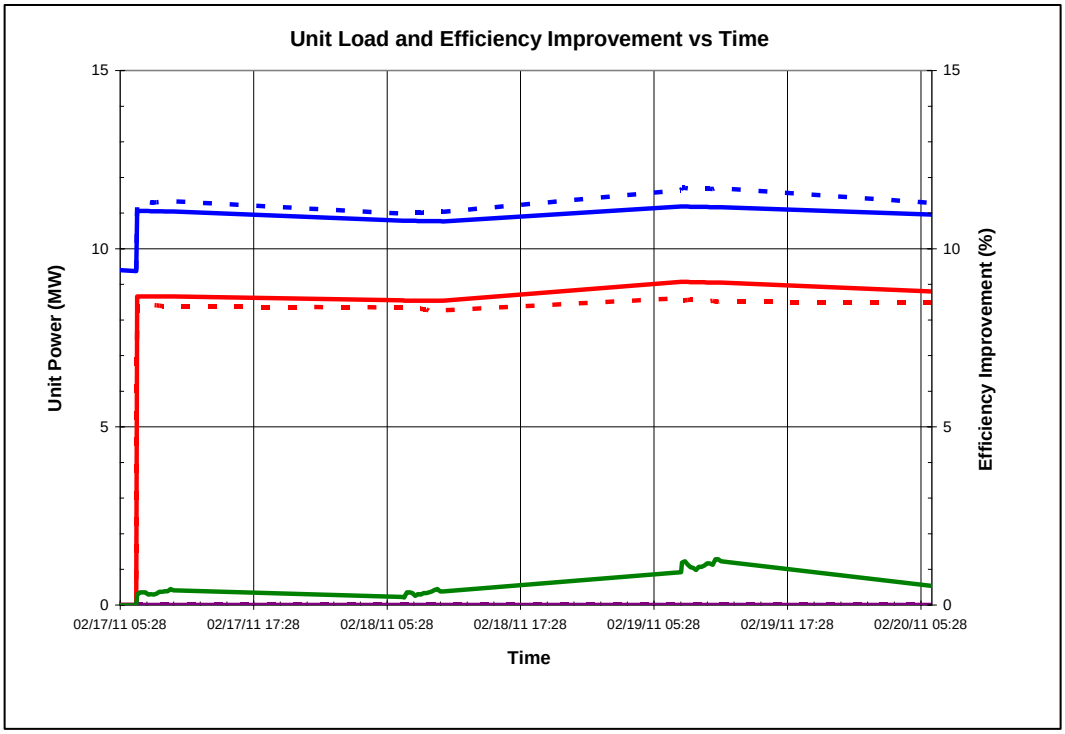

Figure 5.22: Typical Operation Efficiency Results (February 17-20, 2011)

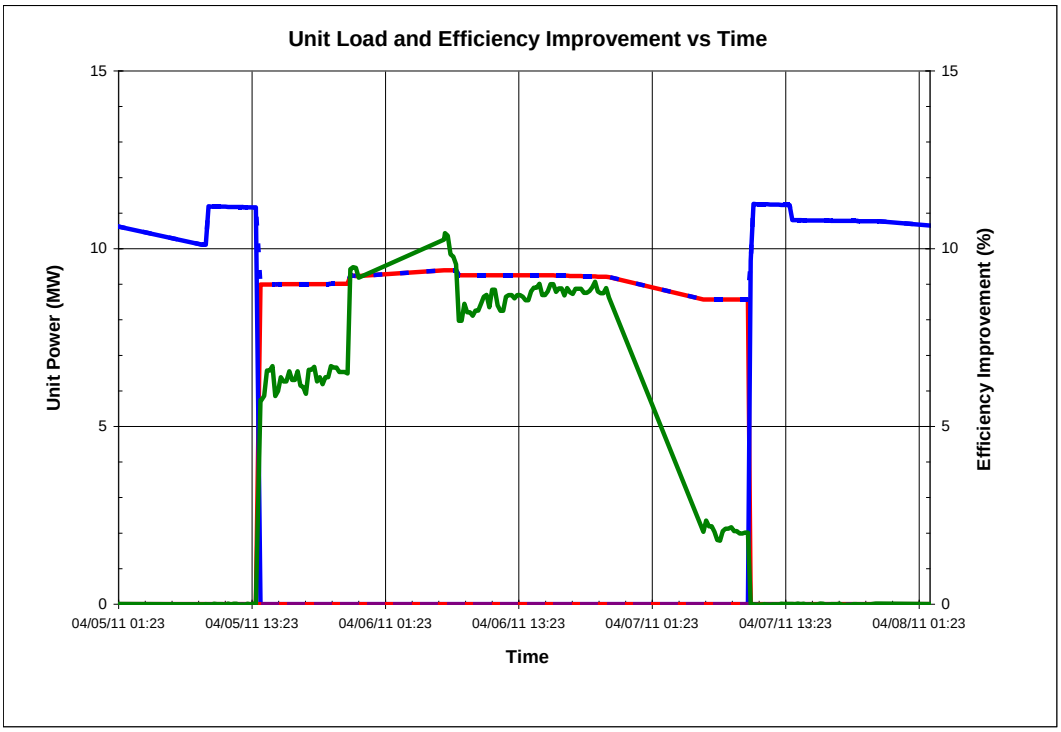

Figure 5.23: Typical Operation Efficiency Results (April 5.7, 2011)

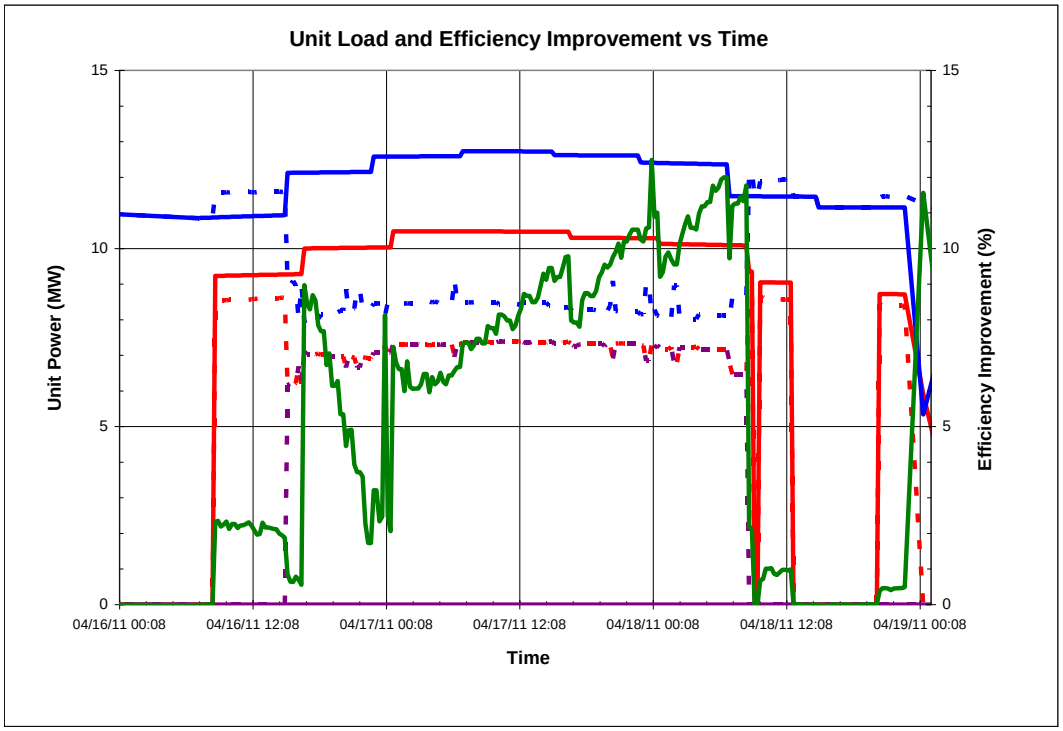

Figure 5.24: Typical Operation Efficiency Results (April 16-18, 2011)

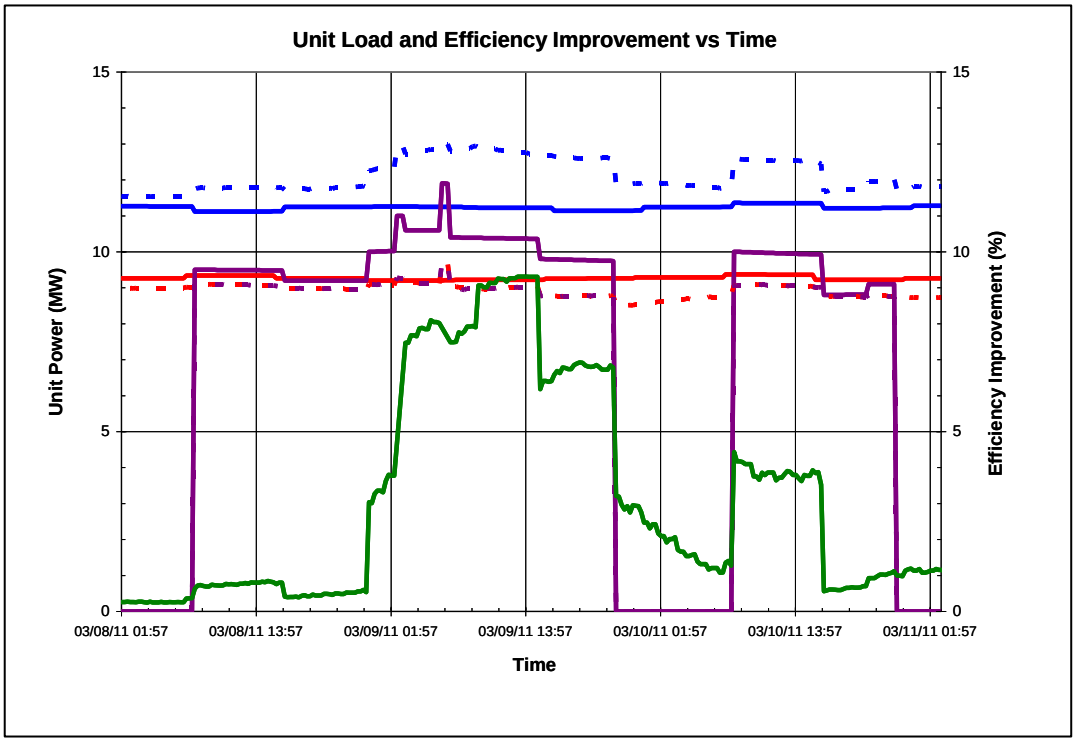

Figure 5.25: Typical Operation Efficiency Results (March 9-11, 2011)

Much of the plant's generation occurs with Unit 1 and Unit 2 operating near – but not at – the optimized power levels, as shown in Figure 5.22. Minor adjustments in the Unit 1 and Unit 2 power levels result in plant efficiency improvements ranging from 0.3% to 1.2%. On numerous occasions, Unit 1 is the only unit in operation but Unit 2 is more efficient, as shown in Figure 5.23. Here, the potential improvements in plant efficiency range from 2% to 10.4%. Figure 5.24 presents an example showing the plant generating with Unit 1 and Unit 2 only, when significant efficiency improvements, ranging from 2.2% to 12.5%, could be achieved with the proper combination of Unit 1, Unit 2, and Unit 3. Figure 5.25 shows plant operation when all three units are operating. With adjustments in the unit power levels, plant efficiency improvements ranging from 0.5% to 9.3% could be achieved.

5.2.3 Scheduling analyses

Scheduling Analyses evaluate how closely the actual plant loads align with the overall peak efficiency curves for the entire plant. The steps for computing the scheduling analyses are shown in the Performance Assessment Manual. Individual unit characteristics combine to create an overall plant efficiency that is the maximum plant efficiency achievable for any given

load with optimized plant dispatch. By scheduling plant loads to align with peak operating efficiency regions when hydrologic conditions, market conditions, and other restrictions permit, more efficient energy generation is achieved.

Figure 5.26 provides typical results from scheduling analyses, showing 2009 results for a gross head of 60 ft. The optimized plant gross head efficiency for 60 ft is shown in red, the actual 2009 monthly generation versus plant power is shown in blue, and the optimized 2009 monthly generation versus plant power is shown in green. Note that the actual generation values tend to occur at power levels past the peak efficiencies for one-unit, two-unit, and three-unit operation, while the optimized generation values correspond to the peak efficiencies.

Using IPL, CPL, and PPL optimized plant efficiency curves, quantitative generation analyses were conducted. Using the CPL characteristics and the archival plant data, the quantity of water used per hour was computed for the entire 2007-2011 data set. That quantity of hourly "fuel" was applied to the appropriate IPL, CPL, or PPL optimized plant gross head efficiency curve to compute optimized generation. Results from the generation analyses are provided in Tables 5.2 through 5.4 for IPL, CPL, and PPL plant characteristics, respectively. In each Table, the actual generation is used as the baseline.

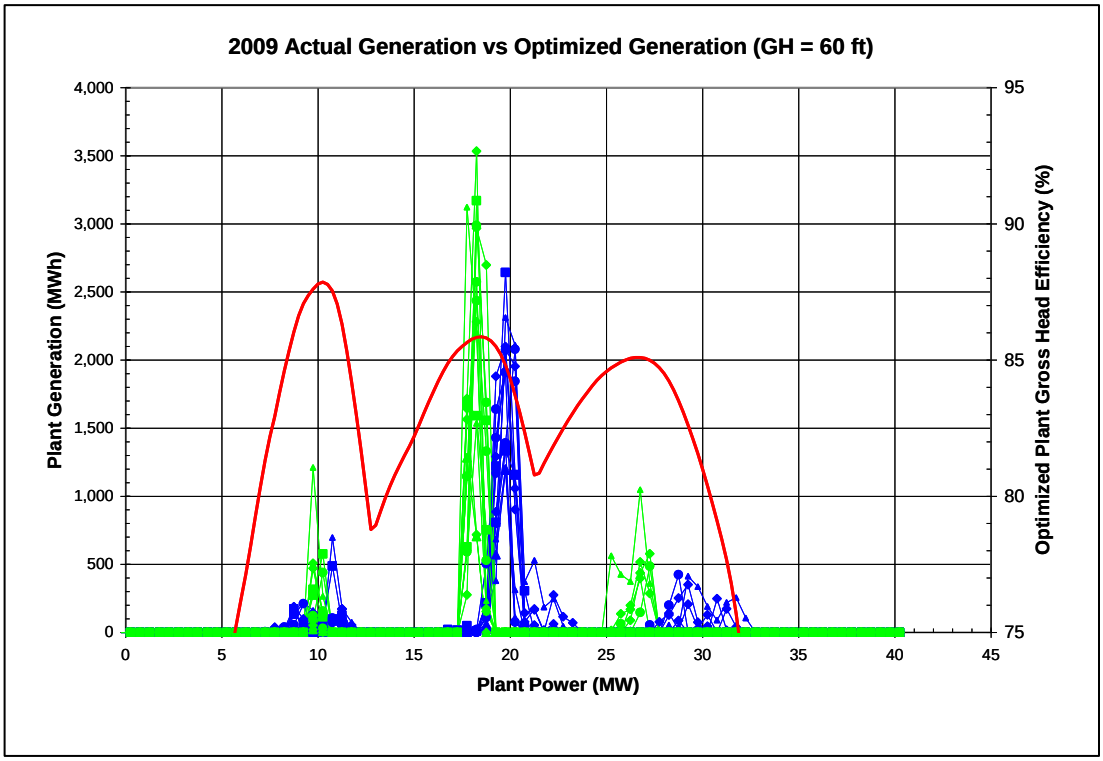

Figure 5.26: Typical Results from Scheduling Analyses (2009; GH = 60 ft)

Table 5.5 Summary of Results from Generation Analyses (IPL)

Year	Actual Annual Generation (MWh)	Optimized Annual Generation (IPL) (MWh)	Improvement (MWh)	Improvement (%)
2007	33,472	34,880	1,408	4.2
2008	35,313	36,328	1,015	2.9
2009	67,362	70,545	3,183	4.7
2010	63,291	66,529	3,238	5.1
2011	29,377	30,457	1,081	3.7

Notes:
1. The 2007 results only include generation from January 1, 2007, through June 30, 2007.
2. The 2011 results only include generation from January 1, 2011, through August 22, 2011.
3. The generation analyses show potential improvements while using the actual amount of water per day.
4. Aeration effects are not included in the generation analyses.

Table 5.6 Summary of Results from Generation Analyses (CPL)

Year	Actual Annual Generation (MWh)	Optimized Annual Generation (CPL) (MWh)	Improvement (MWh)	Improvement (%)
2007	33,472	35,096	1,624	4.9
2008	35,313	36,389	1,076	3.1
2009	67,362	70,570	3,208	4.8
2010	63,291	67,071	3,781	6.0
2011	29,377	30,709	1,332	4.5

Notes:
1. The 2007 results only include generation from January 1, 2007, through June 30, 2007.
2. The 2011 results only include generation from January 1, 2011, through August 22, 2011.
3. The generation analyses show potential improvements while using the actual amount of water per day.
4. Aeration effects are not included in the generation analyses.

Table 5.7 Summary of Results from Generation Analyses (PPL)

Year	Actual Annual Generation (MWh)	Optimized Annual Generation (PPL) (MWh)	Improvement (MWh)	Improvement (%)
2007	33,472	36,800	3,329	9.9
2008	35,313	38,344	3,031	8.6
2009	67,362	74,371	7,010	10.4
2010	63,291	70,243	6,952	11.0
2011	29,377	32,115	2,738	9.3

Notes:
1. The 2007 results only include generation from January 1, 2007, through June 30, 2007.
2. The 2011 results only include generation from January 1, 2011, through August 22, 2011.
3. The generation analyses show potential improvements while using the actual amount of water per day.
4. Aeration effects are not included in the generation analyses.

5.2.4 Avoidable loss analyses

The Avoidable Loss Analyses determine how the optimized dispatch could be improved by reducing avoidable losses. Avoidable losses typically include excessive trash rack losses, excessive penstock losses, and excessive tunnel losses. For this plant, insufficient data was available to evaluate avoidable losses.

5.2.5 Correlation analyses

When continuous measurements of relative or absolute flow rate are available for each unit, Correlation Analyses can be computed to compare the measured efficiencies with the expected unit performance characteristics. For this plant, insufficient data was available for correlation analyses.

5.2.6 Results from optimization-based performance analyses

The potential plant generation improvements due to plant efficiency improvements from optimized plant dispatch, while producing the same power at the same time, averaged about 2.3% for the analyzed years, while the potential generation improvements from using the available water at the peak plant efficiencies averaged about 4.7%. The potential generation improvements from the combination of optimized plant dispatch, improved scheduling, and state of the art turbines and generators averaged about 9.8%. Because no aeration-related performance information was available, these performance analyses were conducted without considering aeration. Aeration-related performance testing should be conducted, and additional performance analyses should be completed to investigate the effects of aeration on the current performance level and to estimate the anticipated effects of aeration on the potential performance level.

6.0 Economic Valuation and Cost Estimate for Upgrades

The power market and economic context for the Rhodhiss facility is included here to document external factors that could affect Rhodhiss dispatch and operations. Future comparative analysis of the assessment results reported herein with those from other facilities having different context will be made. Thus, the context for power market and economics is important that will be required to understand difference in results among assessed facilities. The location of the facility with in the power market topology, the type and prevalence of generation assets in the balancing authority area for the facility, and the nature of the demand within the balancing authority are all relevant to the interpretation of hydropower facility dispatch, performance, and condition data and results. All of the market and pricing data reported herein were obtained from public sources.

6.1 Plant Owner Fleet Characteristics

Figure 6.1 shows the mix of generation assets owned by Duke Energy Carolinas (DEC). According to its 2010 Integrated Resource Plan (IRP), DEC's fuel costs are primarily associated with coal and uranium. Oil and gas are currently used for peaking generation but consumption of natural gas will increase with two new combined cycle units (Buck and Dan River), scheduled to be brought on line at the end of 2011 and the end of 2012 respectively. Generation from the assets summarized in Figure 6.1 is supplemented with purchasing power agreements and wholesale market purchases to serve DEC's load.

According to information collected from FERC Form 714 for years 2006 through 2010, DEC was overall a net exporter of energy to its adjacent balancing authorities during each of those years but net export volume has trended down over that period (from 4.4 million MWh in 2006 to 0.87 million MWh in 2010).

DEC has a summer peaking system load. Maximum hourly load took place in August in four out of five years in the 2006-2010 period. The average peak load June through September during those years has been 20% higher than the one December through March. As for its daily load profile, Figure 6.2 displays the typical daily load profiles for each quarter in 2010.

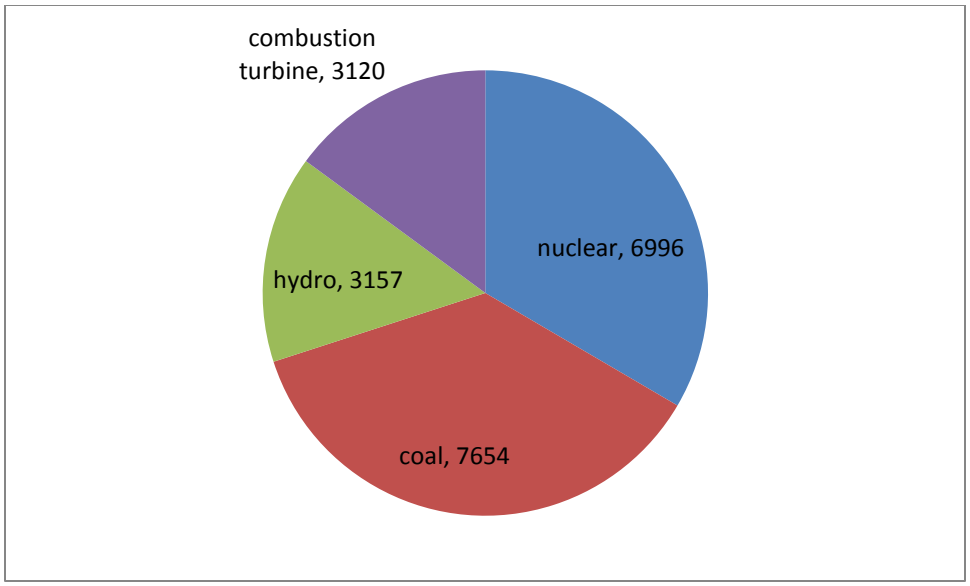

Figure 6.1: Duke Energy Carolinas Generation Mix (MW, 2010)

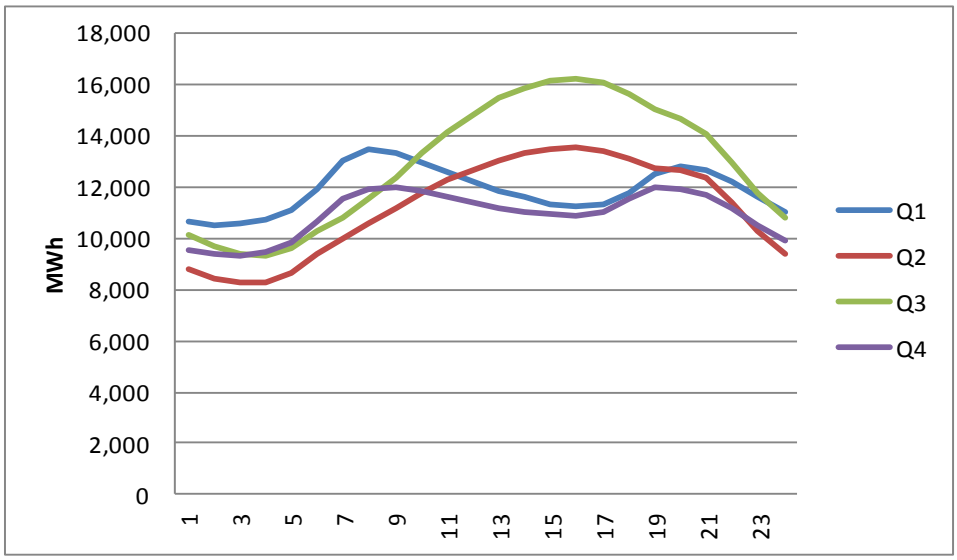

Figure 6.2: Duke Energy Carolinas average load profile (2010)

The summer peak takes place in the afternoon hours while two smaller peaks (one in the morning and one in the evening) characterize the winter load profile. Operational data from Rhodhiss for the 2007-2011 period show that its typical daily power dispatch curves for each quarter follow a similar pattern as those observed in Figure 6.2. Figure 6.3 shows Rhodhiss average power dispatch during each quarter of 2010. Rhodhiss produces approximately 90% of

its annual power between 6 am and 10 pm while approximately 40% concentrates in the afternoon hours (1 pm to 6 pm).

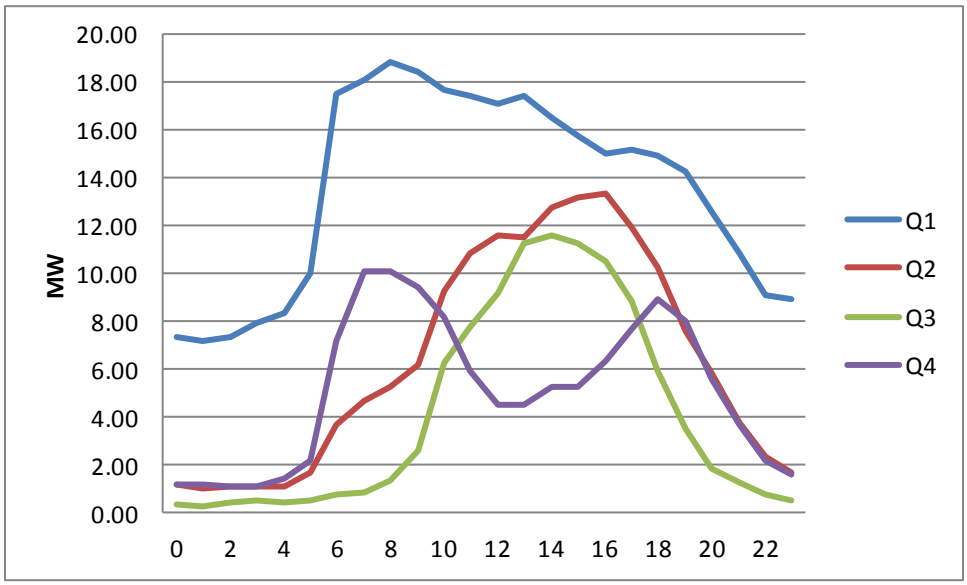

Figure 6.3: Rhodhiss average daily power dispatch profile (2010)

6.2 Market Context

Rhodhiss is located within the footprint of the DEC balancing authority area. DEC is a member of PJM so it could use Rhodhiss' energy and capacity to serve its own customers, provide ancillary services within its control area or exchange energy and/or ancillary services with adjacent balancing authorities (Progress Energy Carolinas2, PJM, South Carolina Electric & Gas, South Carolina Public Service Administration, Southern Company Services, Tennessee Valley Authority and Yadkin).

6.2.1 Energy prices/tariffs

Rhodhiss is located within a non-ISO area so no hourly energy prices are available. FERC Form 714 offers an approximation to the marginal cost of producing energy in the DEC control area. The only adjacent balancing authority to DEC which is an organized market is PJM. From 2006 to 2010, DEC has been a net importer of electricity from PJM. As a reference, the annual average prices of PJM for 2006-2010 are presented in Table 6.1 alongside DEC's average system lambda.

[2] Duke Energy has recently filed a buyout plan with the North Carolina Utilities Commission for acquiring Progress Energy Carolinas.

Table 6.1: Energy values for Rhodhiss production (DEC's system lambda vs. PJM price)

Year	Average System Lambda ($/MWh)	Average PJM Real-Time LMP ($/MWh)[3]
2006	37.73	51.79
2007	36.88	57.34
2008	52.88	71.94
2009	33.39	37.42
2010	34.80	46.13

Values in the two columns are not directly comparable because the system lambda represents the marginal cost of energy generation while the PJM locational marginal price incorporates losses and congestion elements. PJM's generation mix is similar to that of Duke Energy Carolinas. In 2010, 83.9% of total generation in PJM came from coal and nuclear. Thus, there should not be great difference in the marginal cost of energy in these two systems.

The most relevant long-term price forecasts for Rhodhiss are those that the Energy Information Administration (EIA) develops for the SERC_VACAR region, as it contains the DEC balancing authority in which Rhodhiss operates. According to the reference case for the AEO 2012 early release, the price of electricity generation in this region trends down over time in real terms (2010 dollars) from $0.071/kWh in 2011 to $0.063/kWh in 2035 (the average annual growth rate in nominal terms is estimated at 0.10%). This electricity price forecast is obtained from the Electricity Finance and Pricing (EFP) submodule of the National Energy Modeling System (NEMS). Because only a small portion of the SERC-VACAR region is part of an organized wholesale market, the price is a load-weighted average of the competitive price and the regulated price, with the regulated price reflecting generation costs.

6.2.2 Ancillary service prices/tariffs

As for ancillary service tariffs/prices that would be relevant for Rhodhiss, two alternatives are considered here. On one hand, Table 6.2 displays the tariffs for regulation, spinning and supplemental reserves contained in DEC's Open Access Transmission Tariff (OATT). On the

[3] Source: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011q3-som-pjm-sec2.pdf

other hand, Table 6.3 summarizes the PJM market prices for regulation and supplemental reserves. It should be noted that the regulation prices would only be relevant for Rhodhiss if it receives and is able to follow the AGC signals to which these prices are associated. Given the small amount of energy that DEC delivers to PJM, it is unlikely that DEC would provide a lot of ancillary services into that region.

Table 6.2: Duke Energy Carolina's Regulation and Reserves Tariffs

	Regulation and Frequency Response Service	Spinning Reserve	Supplemental Reserve	Units
Monthly service	38	81.5	81.5	$/MW-month
Weekly service	9	19	19	$/MW-week
Daily on-peak	2	4	4	$/MW-day
Daily off-peak	1.3	2.7	2.7	$/MW-day
Hourly on-peak	0.1	0.25	0.25	$/MW-hour
Hourly off-peak	0.05	0.11	0.11	$/MW-hour

Table 6.3: Annual Average Prices for Regulation and Supplemental Reserves in PJM

	Regulation Market Clearing Price ($/MWh)	Day-Ahead Scheduling Reserve Market Clearing Price ($/MWh)
2008	41.05	0.11 (October-December)
2009	23.51	0.07
2010	17.95	0.23
2011	16.41	1.24

These two sets of prices are not directly comparable because the tariffs in DEC's OATT remunerate capacity reserved to provide any of those services during a given time period while PJM prices (at least, for regulation) remunerate the actual number of MWh that the units are

adjusting up or down in response to the AGC signal. DEC's tariff structure does not clarify how/whether the generation adjustments made by generation units are remunerated. The payment for providing spinning reserves in the DEC control area is low when compared to the value of this service in organized markets (e.g., $4.051/MWh in CAISO and $6.23/MWh in NYISO in 2010).

Table 6.3 does not include a price for spinning reserve. PJM's synchronized reserve market has two tiers: Tier 1 resources are those resources that are online and being dispatched for energy and could ramp up their output. Tier 2 resources include units that are backed down to provide synchronized reserve capability, synchronized condensing units, and demand-side resources. Rhodhiss could qualify as a Tier 1 or Tier 2 resource in PJM's Southern Synchronized Reserve Market whose reliability requirements are set by SERC. Tier 1 resources are only paid when they respond to a spinning event, while Tier 2 resources are paid to be available regardless of whether they will be called to respond or not. If Tier 1 and Tier 2 self-scheduled resources are not enough to cover reserve requirements in a given hour, a Tier 2 clearing price is determined. Supplemental reserves have a response time requirement of 30 minutes and their price is set in the Day-Ahead Scheduling Reserve Market, created by PJM in June 2008. The number of hours with non-zero day-ahead scheduling reserve marginal clearing price (DASRMCP) is going down over time (63%in 2009, 57% in 2010 and 44% in 2011) while the average DASRMCP in those non-zero hours has been increasing over that same period.

Historical operational data for Rhodhiss reveal that it is only operated at full load for a small percentage of hours each year. Thus, most of the time, some capacity could be dedicated to the provision of regulation or reserves. To the extent that the proposed upgrades increase the flexibility with which Rhodhiss units (especially Unit 3) could be operated, there would be opportunities to increase total revenue for the plant by providing this type of service.

6.2.3 Applicable incentives/legislation regarding renewable energy

At the federal level, extra energy resulting from a Rhodhiss upgrade would be eligible for the tax credit from efficiency improvements or capacity additions created by the Energy Policy Act of 2005, as long as it was performed by January 1, 2014. Section 1301 of the Energy Policy Act states "the determination of incremental hydropower production shall not be based on any operational changes at such facility not directly associated with the efficiency improvements or additions of capacity". The suggested upgrade of turbine runners in Section 7.3 of this report should qualify in that category. This tax credit amounts to $10/MWh and lasts for 10 years from the date in which the upgrade is complete.

At the state level, North Carolina established a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in 2007. REPS mandates all IOUs in North Carolina to supply 12.5% of their 2020 retail electricity sales in the state from eligible renewable energy sources and/or energy efficiency savings by 2021. Small hydro (up till 10 MW) is among the eligible renewable technologies. But do plant upgrades qualify? DEC currently has a nameplate capacity of 52.5MW registered at NC-RETS that corresponds to hydropower facilities built before the NC REPS was implemented. Although this finding suggests that capacity increases at Rhodhiss could also qualify for inclusion in the registry, an inquiry has been submitted to NC-RETS to try to clarify this point.

To comply with its REPS requirement, DEC not only develops renewable energy resources but also enters into purchase power agreements from renewable power generation facilities and purchases renewable energy credits (RECs). Duke has a standard purchase offer for RECS for years 2011-2026. The offer price is $30/MWh for solar RECs and $6/MWh for RECs from other sources in 2011, increasing by 2.5% every year out to 2026. Thus, if extra energy from upgrading Rhodhiss is eligible to generate RECs, the avoided REC purchases could be counted as a benefit of the upgrade.

6.3 Economic Valuation

6.3.1 Energy benefit ($/MWh)

Calculations have been based on the assumption that the extra energy resulting from a Rhodhiss upgrade would be dispatched without modifying current daily profiles (because they agree well with DEC's load patterns revealed in Figure 6.2 and system prices). Table 6.4 displays the percentages of energy that Rhodhiss has dispatched in the 2008-2010 period on each of three peak periods. The summer (April through September) peak corresponds to the 3 pm – 6 pm time interval, the winter (understood as the first and fourth quarters of the year) morning peak was set to the 6am-9am period and the winter evening peak was set to the 6:00 pm to 8:00 pm. Table 6.5 shows the ratios of the system lambda during those three peak periods versus the 24-hour average.

Table 6.4: Temporal distribution of energy produced by Rhodhiss

Year	Summer peak period	Winter_AM peak period	Winter_PM peak period	Off-peak
2008	0.219	0.212	0.11	0.459
2009	0.131	0.165	0.096	0.608
2010	0.123	0.157	0.092	0.628

Table 6.5: Seasonal peak/off-peak price ratios in Duke Energy Carolinas control area

Year	Average Peak_Summer/24-Hour Average	Average Peak_Winter_AM/24-Hour Average	Average Peak_Winter_PM/24-Hour Average
2006	1.215	1.086	1.043
2007	1.323	1.111	1.133
2008	1.196	1.155	1.046
2009	1.068	1.064	1.035
2010	1.201	1.079	1.038

For estimating its value, the extra energy volumes that could be produced through performance improvements are distributed across the seasonal peak and off-peak hours according to the average of the annual percentages in Table 6.4. Then, the average price ratios from Table 6.5 are applied to the EIA's generation price forecast for the SERC_VACAR region, which can be interpreted as a 24-hour average price.

Using an 8% discount rate and 2010 dollars, the 5, 10 and 20-year present values of the energy benefit are summarized in Table 6.6.

Table 6.6: Present value of energy benefit from Rhodhiss upgrades

	Present Value (2010$)			
	MWh	5-year	10-year	20-year
Operation efficiency average improvement (2007-2011)	1207	352262	582213	832685
Scheduling_CPL average improvement (2007-2011)	2204	643235	1063129	1520495
Scheduling_PPL average improvement (2007-2011)	4612	1346007	2224661	3181726

The energy volumes in Table 6.6 are those discussed in sections 5.2.2 (Operation Efficiency Analysis) and 5.2.3 (Scheduling Analysis) of this report. These volumes can be considered as an upper bound because there are likely to be systemic constraints explaining part of the divergence between actual and performance-optimizing operation patterns.

6.3.2 Capacity and other benefit ($/kW-year)

In addition to providing DO benefits, the proposed Unit 3 turbine upgrade would also provide a modest capacity increase. Furthermore, if its control system were upgraded, Unit 3 could go from just being manually started a few times per year to provide energy, capacity and/or ancillary services on a more regular basis.

Other benefits for which not enough data or agreed upon methodology were available at this point but should be considered as possible enhancements to the upgrade's value proposition are reduced risk of failure, increase in plant availability, reduced insurance, repair and maintenance costs, increase in operating flexibility and environmental benefits.

Table 6.7 displays the combined present value from the energy benefit, avoided REC costs in case that the Rhodhiss upgrade could be registered in NC-RETS and the Section 1301 and tax credit.

The combination of REC production and tax credit increases the present value of the energy benefit by 20% with each of these extra revenues making about half the increase each.

Table 6.7: Present value from energy benefit, REC generation (plus tax credit)

		Present Valve (2010$)		
	MWh	5-year	10-year	20-year
Operation efficiency average improvement (2007-2011)	1207	429370	712794	994423
Scheduling_CPL average improvement (2007-2011)	2204	784036	1301572	1815830
Scheduling_PPL average improvement (2007-2011)	4612	1640641	2723617	3799732

6.4 Cost Estimates

To obtain gains related to process improvement, the costs could be those of developing new generator efficiency curves, developing a routine method for monitoring and cleaning the trash racks and removing debris, and implementing other best practices for performance processes. These costs, as well as the costs for some maintenance and repairs as recommended in this report, are not capital expenditures and should be recouped in the temporal scale of months rather than years.

The capital expenditures are addressed in the following sections for the recommended replacement and upgrade of specific asset components, using the existing formulas developed in industry (e.g., USACE HMI Report and RPRI Hydro Life Extension Modernization Guide). This high-level and standard project cost estimate (AACEI Class 5) is suitable for screening the asset upgrading opportunities across a large number of hydropower facilities. Cost estimates generated from these formulas should not be used to make individual investment decisions at specific facilities. Additional analysis and refinement of the cost estimates outside of the scope of this effort would be needed for the owner to make upgrade decisions. Also, in the case of Rhodhiss, as the owner has done upgrades on Unit 2, it might be easier for them to provide the cost estimates for the same or similar upgrade on Units 1 and 3. Any addition and/or correction in the upgrade cost estimate will be welcome from the plant owners.

6.4.1 Runner replacement of Units 1 and 3

The direct costs associated with a turbine runner replacement include those for turbine model development and test, design and manufacturing of a new runner, installation cost and commission and final testing (EPRI 1999-2000), as well as the dollar value of lost energy during the downtime for replacement (8-14 weeks for each unit). For the turbine runner replacement,

the total fixed and variable costs would be around $1.5 million (in 2010 US dollars) based on the following formula (USACE and MWH, 2010):

$$\textit{Francis runner replacement cost} = \$500{,}000 + (\$220{,}000 \times RDia^{1.3}) + (\$160{,}000 \times Hnet^{0.3})$$

Here, Hnet is the rated net head in feet, which is 59 feet at Rhodhiss; RDia is the Discharge Diameter of the turbine runner in feet, which is 12.4125 feet using the same dimension of runner as for the Unit 2.

For the second identical unit, the cost estimate of runner replacement will be 20% less than the first one, which would be around $1.2 million.

6.4.2 Unit 3 exciting system upgrade

The cost of exciting system depends on the rated and ceiling voltages and currents. The total cost would be around $0.5 million (in 2010 US dollars) for an exciter and voltage regulator replacement, estimated by the formula (USACE and MWH 2010):

$$\textit{Exciting system replacement cost} = \$300{,}000 + (\$18{,}000 \times GMVA)$$

Here, GMVA is the rated generator capacity in MVA, which is 10.625 MVA for the generator capacity of Unit 3.

6.4.3 Unit 3 control system upgrade

The cost of automation and control system can vary greatly with the scope of upgrade. The plant owner should have a better estimate based on their experience of Units 1 and 2 upgrades. The cost of a complete protection and control system replacement (per generator) does not depend so much on the size, type or age of the generator but rather on the desired features. The cost estimate for a typical modern replacement P&C system would be around $400K, including $250-350K for material, $50-90K for engineering, and $40-50K for installation and testing. Installation typically takes 2 electrical workers 1.5 months to install and test (ERPI 2000).

In sum, the estimate of total capital costs for the recommended asset improvements at Rhodhiss facility is around $3.6 million.

6.5 Economic Feasibility and Financing Options

The above high-level standard cost estimates would not allow constructing benefit-cost ratios or net present values at this time for the upgrading project.

7.0 Conclusion and Recommendations

7.1 Summary of Condition and Performance Assessment Results

The Duke Energy Rhodhiss hydro plant has three units that have been in commercial operation since 1925. From 1999 to 2002, several upgrades were completed to Units 1 and 2 as part of Duke Energy's HydroVision program. Unit 3 did not receive significant modifications or upgrades, and is only operated during high water events, very high demand periods, or outages for Units 1 and 2. Units 1 and 2 are automated while Unit 3 must be manually started. The overall condition of Rhodhiss units and plant is fair, though many technological features still in use date back to the original construction over 85 years ago, and further evaluation and assessment of the facility and its operations is warranted.

During the years between 2007 and 2011, the Average Power Production (APP) of Rhodhiss plant was 6.32 MW based on the actual operations records, while the Long-Term Stream Power (LTSP) was 7.78 MW. The potential plant generation improvements due to plant efficiency improvements from optimized plant dispatch, while producing the same power at the same time, averaged about 2.3% for the analyzed years. The potential generation improvements from using the available water at the peak plant efficiencies averaged about 4.7%. The potential generation improvements from the combination of optimized plant dispatch, improved scheduling, and state of the art turbines and generators averaged about 9.8%.

7.2 Environmental and Other Constraints Affecting Performance

There is currently no minimum flow requirement at Rhodhiss hydropower facility but only a daily minimum discharge which is met by daily generation. The normal flow of the river is managed by Units 1 and 2 due to their sufficient capacity. Unit 3 is usually only run during very high demand periods or when there is the potential for spilling, because Units 1 and 2 are automated and Unit 3 must be manually started.

The plant will be expected to comply with North Carolina's dissolved oxygen (DO) requirements when a new license is issued. However, the existing plant configuration has limited ability to enhance DO. To help with the DO requirements, the plant has supplemental air inlet valves that can open along with the turbine vacuum breakers to allow air through the hollow stay vanes and discharges below the runners. There are plans for installation of an aerating runner for Unit 3 in the future. It does not appear that proposed methods for handling DO will have a serious impact on efficiency.

According to plant personnel, cavitation erosion has been only a minor problem although the Units 1 and 3 cast iron runners have been in service for 86 years. Except for some constraints from the manually operated Unit 3, there are no operating constraints from cavitation and vibration problems or from the limited capacity of generators.

There is no notable constraint from the DEC transmission Infrastructure or from the upper limit of power system load demands.

7.3 Prioritized Opportunities for Production and Reliability Improvement

There are several opportunities at Rhodhiss to apply updated technology to improve unit and plant efficiency and reliability, as well as the opportunities for performance process improvement. Specific recommendations that highlight these opportunities are listed and prioritized as follows:

- A more modern hydraulic design and improved method of delivering aeration through the turbine runner may provide significant efficiency improvements. Aeration-related performance testing should be conducted, and additional performance analyses should be completed to investigate the effects of aeration on the current performance level and to estimate the anticipated effects of aeration on the potential performance level.
- Cast iron runners on Units 1 and 3, as well as Unit 3 gates and bushings, are approaching the end of their service lifetimes, and should be replaced or rehabilitated.
- The exciter replacement project for Unit 3, which will eliminate losses associated with the exciter field and improve exciter response, should be completed.
- Assuming that the GSU transformers are to continue to remain in service for a length of time, then a proper dry out and oil reclamation would be recommended. However, consideration should be given to the scheduled replacement of these 86 year old GSU transformers to provide for future reliability and efficiency.
- In order to provide the most efficient utilization of the available water resources, new generator efficiency curves should be developed and used in determination of the optimal generation mix.
- The Unit 3 control system upgrade should be completed.
- As a means to achieve added efficiency improvement, the plant should develop a routine method for monitoring and cleaning the trash racks and removing debris.

In summary, there are numerous opportunities for improving efficiency and reliability at the Rhodhiss facility. Continual follow up and implementation for HydroVision recommended

upgrades for Unit 3 along with the recommendations outlined in this assessment report will provide reasonable assurance of achieving these efficiency gains.

7.4 Recommendations for Additional Studies

To resolve uncertainties in prioritization, costs, and benefits from the above recommended improvement projects, the following studies are suggested (basically for beyond the scope of current HAP assessment):

1) Further on-site inspections and testing of turbine-generator units to build more accurate unit performance data (i.e., efficiency curves) and condition indicators.
2) Economic valuation of reliability improvement from the recommended upgrades or replacements for those components that may not directly result in efficiency and energy production increases but would definitely reduce the risk costs (e.g., the transformer replacement). This extended study would include the condition-based likelihood of equipment failures, the cost consequence the failures, the reduced risk costs, and the reduced LCOE for the remaining lifespan of units and plant.
3) Study on potential environmental benefits from improved performances (e.g., reduced GHG emissions per MWh due to efficiency improvement).
4) Economic valuation of other benefits from the recommended upgrade activities, including the reduced annual O&M costs, reduced insurance premium, and increased operating flexibility.
5) Project-specific cost analysis and feasibility studies for recommended upgrade activities, including detailed engineering design, cost quotation of replacing equipment, the cost of energy losses during the planned outage for upgrading projects, and a detailed cost-benefit analysis.

8.0 References and Data Sources

1) HAP Team (2011). HAP Best Practice Category of Hydropower Unit and Plant Efficiency Improvement, prepared by Mesa, HPPi, and ORNL.
2) HAP Team (2011). HAP Condition Assessment Manual, prepared by Mesa, HPPi, and ORNL.
3) HAP Team (2011). HAP Performance Assessment Manual, prepared by HPPi and ORNL.
4) Duke Engineering Services for Duke Power Company, "Rhodhiss Hydro Station – HydroVision Scope Document", February 1998.
5) Miller, Richard R., "Revitalizing Hydro Facilities to Maximize Their Long-Term Value", *Hydro Review*, February 1996.
6) Original Turbine and Generator Efficiency Curves, Westinghouse Electric and Manufacturing Co., September 1927.
7) Rhodhiss Units 1 & 2 Generator Curves, General Power Engineering Associates, Inc. (GPEA), March 1999.
8) Rhodhiss GSU Nameplate
9) Brinson, Earl M., "Electrical Features – Duke's Hydro Upgrade Program", Hydro Upgrade Program.
10) Herrin, Randy and Mike Sloop, "A Control System Automation Project for Duke Power Hydroelectric System", Waterpower 1997.
11) Rhodhiss License Information (Catawba-Wateree Project No. 2232), Duke Energy.
12) Rhodhiss drawing portfolios for electrical, mechanical, architectural, and structural.
13) USACE and MWH (2010). Final Report of Hydropower Modernization Initiative (HMI) Asset Investment Planning Program, MWH prepared for U.S. Army Corps of Engineers Northwest Division, Hydroelectric Design center, October 21, 2010.
14) EPRI (1999-2000). *Hydro Life Extension Modernization Guides*: Volume 1-7. EPRI, Palo Alto, CA: TR-112350-V1-7.

For overall questions
please contact:

Brennan T. Smith, Ph.D., P.E.
Water Power Program Manager
Oak Ridge National Laboratory
865-241-5160
smithbt@ornl.gov

or

Qin Fen (Katherine) Zhang, Ph. D., P.E.
Hydropower Engineer
Oak Ridge National Laboratory
865-576-2921
zhangq1@ornl.gov