Effects of Electricity Markets on Suboptimization of Pumped-Storage Hydroelectric Plants

by

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Abstract

A recent project, sponsored by the U. S. Department of Energy and co-sponsored by the hydropower industry, focused on quantifying and maximizing the benefits to transmission grids provided by conventional and pumped-storage hydroelectric plants. As part of that project, detailed plant performance analyses were conducted using unit and plant performance characteristics and one-minute plant operational data from 2008, 2009, and 2010 for five pumped-storage plants. These five case studies encompass three markets (MISO, NYISO, and PJM) and one non-market region (Southeast area). Owners for the five plants include three investor-owned utilities, one state power authority, and one federal power corporation. This paper describes results from detailed performance analyses which evaluated reductions in overall plant efficiencies under a variety of operation-related and market-related conditions for the plants.

1. Introduction

The U. S. Department of Energy's (DOE's) Hydropower Grid Services Project was initiated to quantify and maximize the benefits provided by conventional and pumped-storage hydroelectric projects to transmission grids, particularly for the integration of variable renewables. Details of the Hydropower Grid Services Project, including a project overview, a description of the modeling approach, a report on plant cost elements, and recent publications, are provided through the Electric Power Research Institute's (EPRI's) web site [EPRI, 2012].

A previous study examining the effects of the MISO ancillary services market on suboptimization of a conventional hydroelectric facility reported a performance reduction by an average of 3.0%, due primarily to the practical necessity of maintaining additional units on line at lower loads to meet anticipated system demand and to avoid excessive unit cycling [March et al., 2010]. This paper utilizes results from performance assessments for the Hydropower Grid Services Project to extend the previous work and examine suboptimization of pumped-storage plants under market and non-market conditions. The paper describes the performance assessment process, provides results from performance assessments for the five pumped-storage plants, and discusses the results in a market/non-market context.

2. Overview of Performance Analyses

The performance assessments are based on a set of analyses to quantify unit and plant performance and to enable the investigation of potential opportunities for operations-based and equipment-based performance improvements, leading to additional generation. This paper briefly addresses the processes and methodologies used for the quantitative performance analyses, and additional details are available elsewhere [March, 2008; DOE, 2011].

An overview of the optimization-based performance analyses is shown in Figure 2-1.

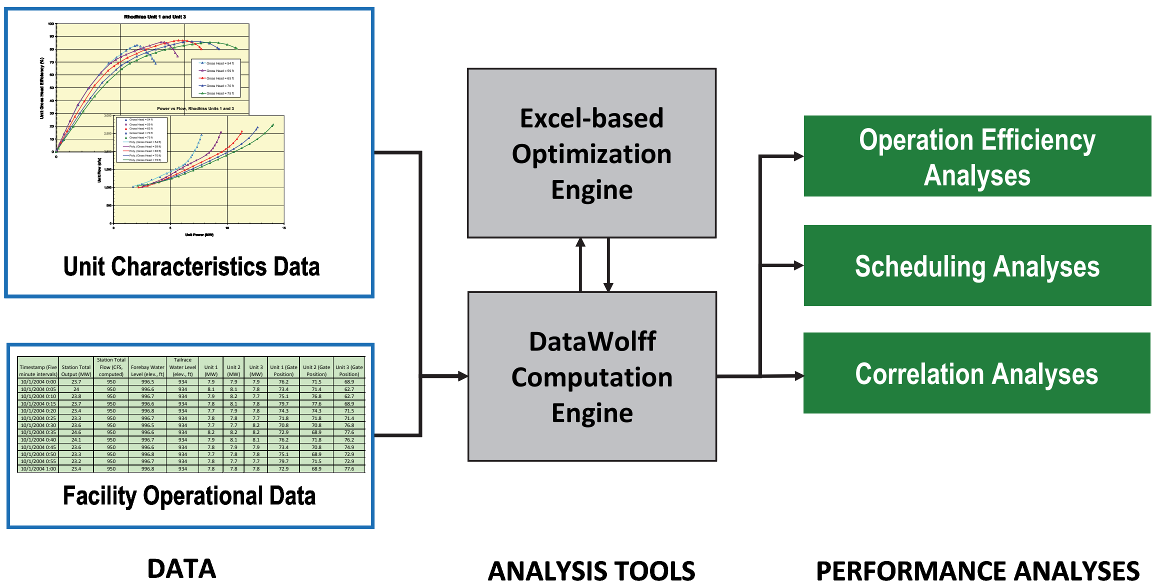

Figure 2-1: Overview of Performance Analyses

Unit characteristics and facility operational data are discussed in Section 3, "Data for Performance Analyses." The performance analysis tools are discussed in Section 4, "Tools for Performance Analyses." An overview of optimization-based performance analyses is provided in Section 5, and results from the performance analyses are provided in Section 6. Section 7 summarizes and discusses the results.

3. Data for Performance Analyses

The primary data needs for performance analyses include unit characteristics data and facility operational data, which are discussed in the following subsections.

Unit Characteristics Data – Hydroelectric generating facilities convert the potential energy of stored water and the kinetic energy of flowing water into a useful form, electricity. This fundamental process for a hydroelectric generating unit is described by the generating efficiency equation, defined as the ratio of the power delivered by the unit to the power of the water passing through the unit. The general expression for this efficiency (η) is

$$\eta = \frac{P}{\rho g Q H}$$

where P is the output power, ρ is the density of water, g is the acceleration of gravity, Q is the water flow rate through the turbine, and H is the head across the unit.

Efficiency curves provide guidance for the effective use of a hydropower unit or facility. The points of most efficient operation can be identified, and the efficiency penalty for operating away from the optimum can be quantified and evaluated relative to the potential economic benefits from generating at another power level.

Facility Operational Data – Typically, facility operational data is obtained from multiple sources, including plant personnel, central engineering staff, and load control personnel. Essential operational data for operation efficiency analyses, generation scheduling analyses, and correlation analyses include:

- Timestamp;
- Unit Power;
- Unit Flow;
- Headwater Level;
- Tailwater Level;
- Unit Status (e.g., available, unavailable, condensing).

4. Tools for Performance Analyses

As shown previously in Figure 2-1, the primary tools for performance analyses include an optimization engine and a computation engine, which are described in the following subsections.

Optimization Engine – The optimization engine used for the optimization-based performance analyses is implemented using the Solver tool in Microsoft Excel. A brief summary of the implementation is included below, and a detailed explanation is included elsewhere [DOE, 2011].

The optimization engine is used to determine how a given plant power level is allocated among the units to provide the highest possible plant efficiency. The information required includes the plant power, headwater, tailwater, and the unit characteristics. The optimization engine can also incorporate constraints, such as a preferred unit dispatch order. Given this information, the optimization engine computes the unit power allocation that meets the given plant power with the lowest possible water usage, providing the highest possible plant efficiency.

Computation Engine – The primary computation engine is DataWolff, an Excel-based program that enables the automating of multiple data analyses. Additional configuration of the computation engine with specific analysis scripts and calculation libraries is required for each particular type of analysis. The optimization-based performance analyses use the procedures described in Section 5 and provided in detail elsewhere [DOE, 2011].

5. Optimization-Based Performance Analyses

Optimization technologies and recent advances in automated data analyses provide the tools for conducting detailed, optimization-based performance analyses [March and Wolff, 2003; March, 2004; March and Wolff, 2004; March et al., 2005; Wolff et al., 2005; Jones and Wolff, 2007; March, 2008]. Typical optimization-based performance analyses include operation efficiency analyses, generation scheduling analyses, and correlation analyses. Results from these analyses can be presented in easily understood units, including lost energy opportunity (LEO, in MWh) and lost revenue opportunity (LRO, in $). A diagram of the overall process for optimization-based performance analyses is shown in Figure 5-1, and the specific analyses are described in the following subsections.

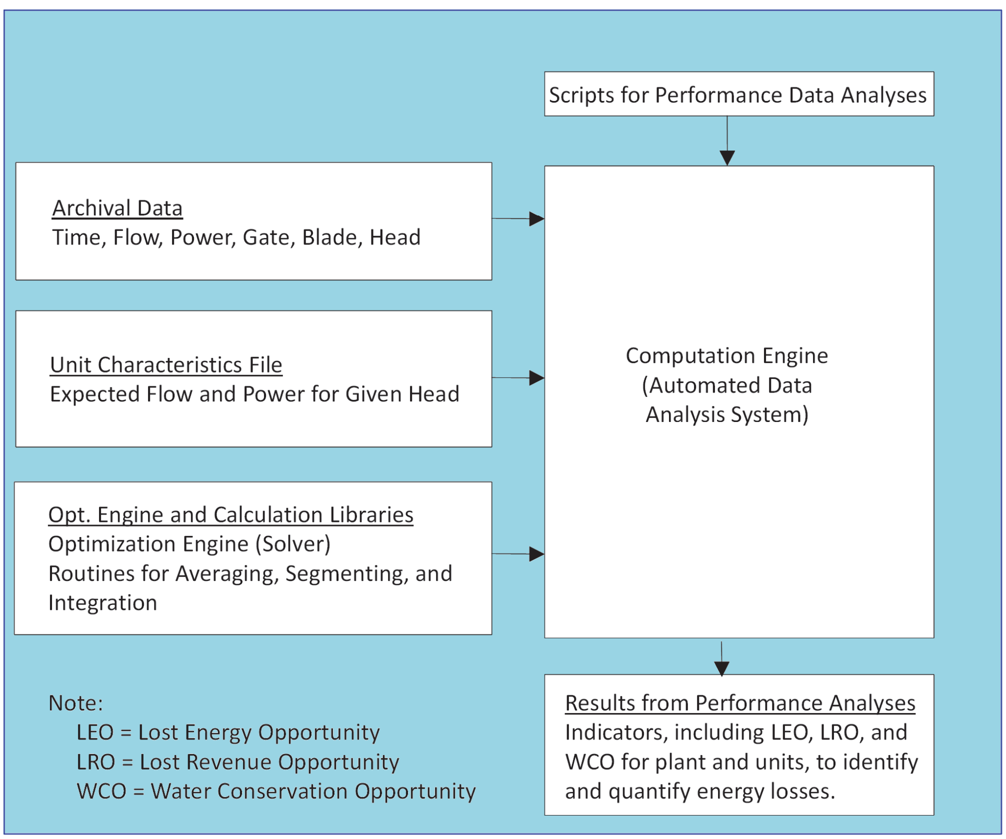

Figure 5-1: Process Diagram for Optimization-Based Performance Analyses

Operation Efficiency Analyses – 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 provided elsewhere [DOE, 2011]. 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).

The optimized plant efficiency is compared to the actual plant efficiency, as operated, to evaluate the potential gain that could be achieved for that time step. Note that the deficit in operation efficiency (i.e., 100% minus the operation efficiency) represents the efficiency gain theoretically achievable by continuously optimizing the plant load. 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. Operation efficiencies close to 100% are achievable with control systems capable of optimization-based AGC [Giles et al., 2003; March and Wolff, 2004].

<u>Generation Scheduling Analyses</u> – Generation 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 generation scheduling analyses are elsewhere [DOE, 2011]. 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.

6. Results from Performance Analyses

<u>Overview of Facilities</u> – Through April 2012, detailed performance assessments have been completed for five pumped-storage facilities, using unit and plant performance characteristics and one-minute plant operational data from 2008, 2009, and 2010. These five plants encompass three markets (MISO, NYISO, and PJM) and one non-market region (Southeast area). Owners for the five plants include three investor-owned utilities, one state power authority, and one federal power corporation. Due to the confidential nature of the performance data, some results from the assessments are not available for public distribution.

<u>Single Unit Performance and Plant Performance</u> - The single unit performance data for the five plants was supplied by the facility owners and verified, where possible, through volumetric flow measurements using the upper reservoirs [Wolff and March, 2010; Wolff et al., 2010]. Based on the unit performance curves, the optimization engine (see Section 4) was used to compute optimized plant gross head efficiencies for each facility. Figure 6-1 shows typical optimized plant gross head efficiencies versus plant power at multiple gross heads for one of the pumped-storage plants. For each head, the first peak in Figure 6-1 corresponds to the operation of the most efficient unit (or any unit, if the units are identical), the second peak corresponds to the most efficient operation of the two most efficient units, the third peak corresponds to the most efficient operation of the three most

efficient units, etc. As more units operate, the peak efficiencies fall, and the peaks become broader.

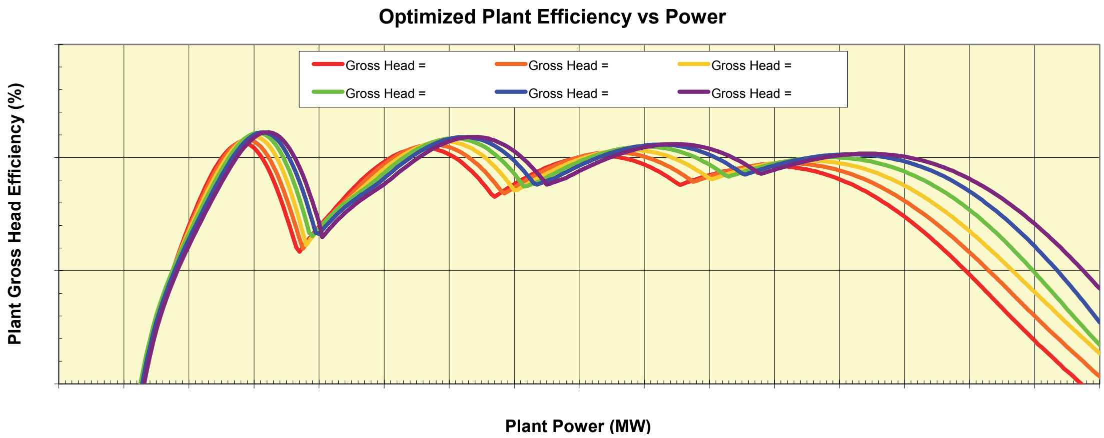

Figure 6-1: Typical Optimized Plant Gross Head Efficiency versus Plant Power

<u>Operation Efficiency Analyses</u> – The operation efficiency analyses use the unit efficiency characteristics and archival operations data to determine how closely the actual dispatch matches the optimized dispatch while meeting the actual power versus time. The computational steps for determining the operation efficiency are discussed elsewhere [DOE, 2011]. 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 for the five pumped-storage plants are summarized in Table 6-1.

Plant	Computed Improvement (%) from Operation Eff. Analyses
1	0.5
2	0.01
3	0.9
4	1.1
5	0.5

Table 6-1: Summary of Results from Operation Efficiency Analyses for Five Plants

The average for the potential plant generation improvements from direct optimization, while producing the same power at the same time, ranged from a low of 0.01% for Plant 2, which participates in an energy market only and provides no ancillary services, to a high of 1.1% for Plant 4, which participates in both energy and ancillary services markets.

Several examples are provided in Figures 6-2 through 6-4. In these figures, the colors of the lines follow this convention:

1. The red line represents the actual Unit 1 generation, and the dashed red line represents the optimized Unit 1 generation (left axis, MW for Unit 1);
2. The orange line represents the actual Unit 2 generation, and the dashed orange line represents the optimized Unit 2 generation (left axis, MW for Unit 2);
3. The yellow line represents the actual Unit 3 generation, and the dashed yellow line represents the optimized Unit 3 generation (left axis, MW for Unit 3);
4. The bright green line represents the actual Unit 4 generation, and the dashed bright green line represents the optimized Unit 4 generation (left axis, MW for Unit 4);
5. The dark green line represents the potential plant efficiency improvement from improved optimization while matching the actual plant power (right axis, % of total generation).

Figure 6-2 shows a full day's generation on June 25, 2010, for one of the plants. On this day, the plant's power level varied by about 100 MW from 10:30 AM to 12:45 PM, with three units operating at unequal loads. From 1:00 PM to 6:00 PM, the plant power level increased by several hundred MW and varied by about 200 MW, with four units operating at unequal loads. From 6:15 PM to 8:45 PM, the plant power level dropped and varied by about 200 MW, with three units operating at unequal loads. During almost all of the three unit operation, the optimized operation requires four units. The combination of having the correct number of units online and having the load equally distributed among the units would provide plant efficiency improvements of up to 4.0%, corresponding to 184 MWh of increased generation (or the equivalent conserved water in the upper reservoir) for the day.

Figure 6-3 shows a period of operation on July 13, 2010, for a different plant. From 4:30 PM to 8:15 PM, the plant power level varied by about 200 MW, with four units operating at approximately equal loads. For most of the four-unit operation during this period, the operation efficiency results show three-unit operation, providing plant efficiency improvements of up to 1.7% and corresponding to 62 MWh of increased generation (or the equivalent conserved water in the upper reservoir) for the time period.

Figure 6-4 shows a period of operation on September 1, 2010, for a third plant. For much of the day, three individual units are dispatched by the market to operate near each unit's maximum capacity, when operation of four units at equal power levels near best efficiency would provide overall plant efficiency improvements of up to 5.8%, corresponding to 285 MWh of increased generation (or conserved water) for the day.

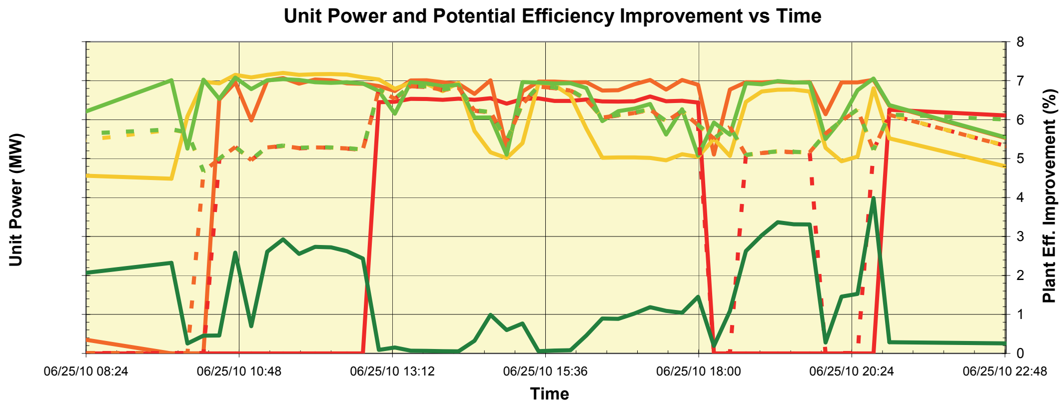

Figure 6-2: Typical Operation Efficiency Results (June 25, 2010)

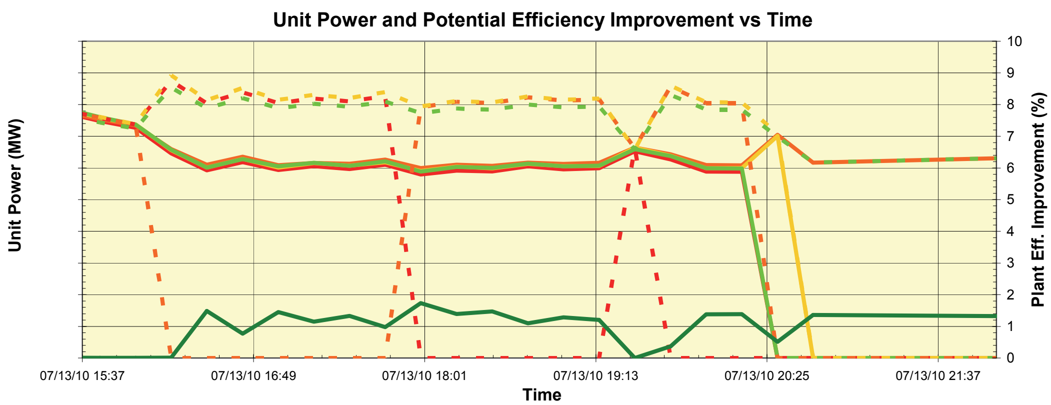

Figure 6-3: Operation Efficiency Results (July 13, 2010)

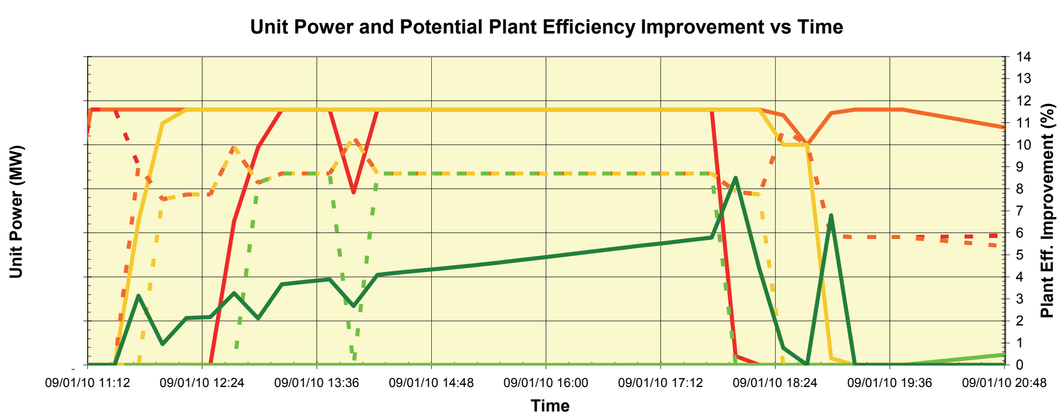

Figure 6-4: Operation Efficiency Results (September 1, 2010)

The generation improvements summarized in Table 6-1 and shown graphically in Figures 6-2 through 6-4 are based on an unconstrained optimization. For each plant, the actual operation is based on power system needs or market requirements for energy and ancillary services, which can dictate the number of operating units, and on maintenance considerations, which can limit the number of allowable starts and stops. Consequently, some of the generation improvements identified by the operation efficiency analyses may not be practically achievable. However, for several of these plants, much of the potential generation increase from direct optimization may be cost-effectively achievable through automation and control system improvements.

<u>Generation Scheduling Analyses</u> - The generation scheduling analyses evaluate how closely the actual plant power levels align with the overall peak efficiency curves for the entire plant. The steps for computing the generation scheduling analyses are provided elsewhere [DOE, 2011]. 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, power system needs, market conditions, and other restrictions permit, more efficient energy generation is achieved.

Figures 6-5 and 6-6 provide typical results from generation scheduling analyses. In each figure, the optimized plant gross head efficiency for the particular head is shown in red, the actual monthly generation versus plant power is shown in blue, and the optimized monthly generation versus plant power is shown in green. The optimized generation occurs at or near the peak efficiencies corresponding to the number of operating units. The plant in Figure 6-5 is dispatched for energy and ancillary services within a vertically integrated power system, rather than in a defined market. This plant tends to operate within a range of powers near the best efficiency values. Virtually identical results were found for the other plant dispatched for energy and ancillary services within a vertically integrated power system. The plant in Figure 6-6 operates in a well-established market where it is dispatched by individual units primarily for ancillary services rather than energy during the time period shown in the figure. This plant operates over a wide range of power levels.

For each plant, quantitative analyses were conducted by using the unit performance characteristics, the optimized plant efficiency curves over the head range, and the archival plant data. The actual quantities of water used for generation per hour for the entire data set were computed. Those quantities of hourly "fuel" were applied to the optimized plant gross head efficiency curves for the appropriate heads to compute optimized generation. Results from the generation analyses for the five plants are provided in Table 6-2. The average for the potential plant generation improvements based on the generation scheduling analyses ranged from a low of 0.4% for Plant 2, which participates in an energy market only and provides no ancillary services, to a high of 2.9% for Plant 3, which participates in both energy and ancillary services markets but is primarily dispatched by the market for ancillary services.

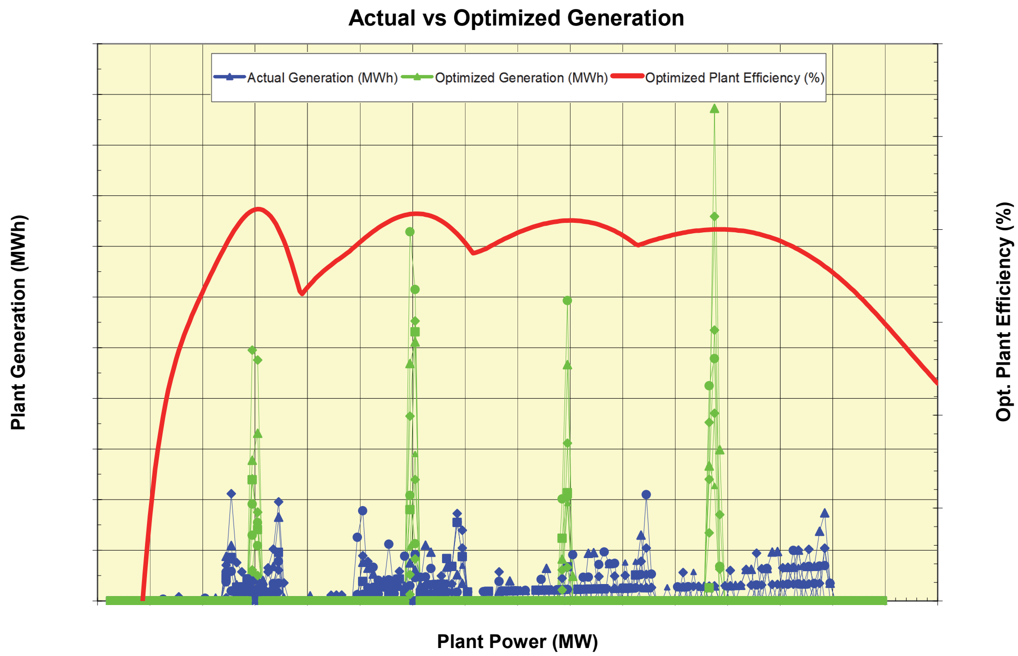

Figure 6-5: Typical Results from Scheduling Analyses (Plant Dispatched for Energy and Ancillary Services in a Vertically Integrated Power System)

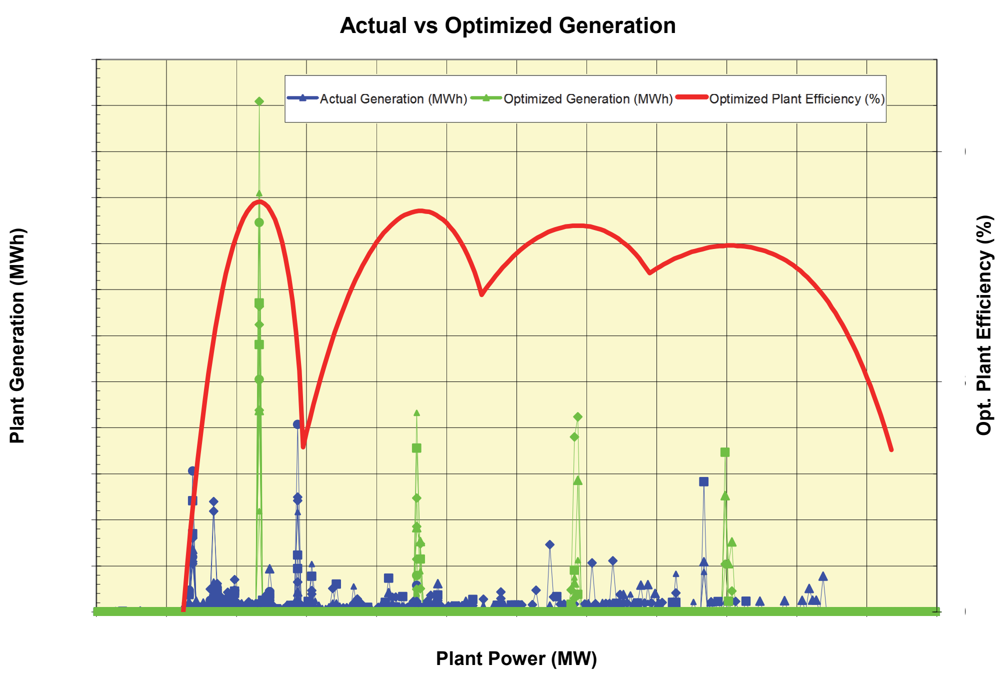

Figure 6-6: Typical Results from Scheduling Analyses (Plant Dispatched Primarily for Ancillary Services in an Established Market)

Plant	Computed Improvement (%) from Scheduling Analyses
1	1.0
2	0.4
3	2.9
4	0.9
5	0.4

Table 6-2: Summary of Results from Generation Scheduling Analyses

Results from both operation efficiency analyses and generation scheduling analyses are summarized by market or region in Table 6-3. One plant was not included in the Table 6-3 results because the plant does not provide ancillary services. The average for the potential plant generation improvements based on the operation efficiency analyses was 0.5% for the two non-market plants in the Southeast and 1.0% for the two plants in the PJM or NYISO markets. The average for the potential plant generation improvements based on the generation scheduling analyses was 0.7% for the two non-market plants in the Southeast and 1.9% for the two plants in the PJM or NYISO markets.

Market/Region	Avg. Computed Improvement (%) from Operation Eff. Analyses	Avg. Computed Improvement (%) from Scheduling Analyses
Southeast	0.5	0.7
PJM and NYISO	1.0	1.9

Table 6-3: Summary of Results from Generation Scheduling Analyses by Market/Region

7. Conclusions and Recommendations

This report summarizes results from optimization-based performance analyses conducted for five pumped-storage plants as part of the EPRI/DOE Hydropower Grid Services Project.

Conclusions and recommendations based on these results are listed below:

1. The average for the potential plant generation improvements from direct optimization, while producing the same power at the same time, ranged from a low of 0.01% for Plant 2, which participates in an energy market only and provides no ancillary services, to a high of 1.1% for Plant 4, which participates in both energy and ancillary services markets. For several of these plants, much of the potential generation increase from direct optimization may be cost-effectively achievable through automation and control system improvements. Due to the high levels of annual generation at these plants, even a fractional percentage of improvement has significant economic value.

2. The average for the potential plant generation improvements based on the operation efficiency analyses was 0.5% for the two non-market plants in the Southeast and 1.0% for the two plants in the PJM or NYISO markets. One plant was not included because the plant does not provide ancillary services.
3. The average for the potential plant generation improvements based on the generation scheduling analyses ranged from a low of 0.4% for Plant 2, which participates in an energy market only and provides no ancillary services, to a high of 2.9% for Plant 3, which participates in both energy and ancillary services markets but is primarily dispatched by the market for ancillary services. For the four plants which provide ancillary services, these results represent the approximate energy cost for providing ancillary services.
4. The average for the potential plant generation improvements based on the generation scheduling analyses was 0.7% for the two non-market plants in the Southeast and 1.9% for the two plants in the PJM or NYISO markets. One plant was not included because the plant does not provide ancillary services.
5. The non-market operations of pumped-storage plants by the two vertically integrated utilities resulted in more efficient performance of their plants than the two market-based utilities. Opportunities exist for plant improvements to reduce avoidable suboptimization of pumped-storage plants. Opportunities may also exist for market improvements to reduce suboptimization of pumped-storage plants.
6. The long term maintenance consequences of these operational differences among non-market and market plants are unknown, and additional investigation is warranted.

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