GENERATION COST FORECASTING USING ON-LINE THERMODYNAMIC MODELS

C. Daycock
INTERGEN

R. DesJardins, P.E.
S. Fennell, P.E.
GENERAL PHYSICS CORPORATION

ABSTRACT

Most power generation companies are utilizing limited or outdated information to characterize generating assets for economic dispatch and energy trading. In some cases, this data may be several years old. In other cases, it might be obtained from original plant acceptance test data or design data, adjusted for seasonal weather variations. In either case, the data do not represent the unit’s actual capacity or heat rate, without real-time actual equipment condition and ambient conditions.

This paper presents a method used by InterGen, which leverages the latest web technologies to more precisely predict generating unit performance in terms of capacity, heat rate, and incremental heat rate. The method utilizes rigorous thermodynamic models of the power plant cycle, in combination with on-line performance monitoring, to predict unit performance based on forecasted ambient and actual unit equipment conditions. While such thermodynamic models accurately represent the performance of all types of plants, they are especially well suited for gas turbine-based combined cycle plants, where discontinuities and inflections in the input/output relationship challenge traditional methods.

The paper demonstrates how this new method has been implemented across a broad range of plants to improve profits. It also describes the benefits that have been achieved on the non-regulated side of the market by utilizing this approach to better predict production costs.

INTRODUCTION

Most power generation companies are utilizing limited or outdated information to characterize generating assets for economic dispatch and energy trading. In some cases, this data may be several years old. In other cases, it might be obtained from original plant acceptance test data or design data, adjusted for seasonal weather variations. In either case, the data do not represent the unit’s actual capacity or heat rate, without real-time actual equipment condition and ambient conditions.

The declining margins experienced by the power industry over the past 3 years put more pressure on understanding actual operating costs prior to committing assets in the open market. A decision to dispatch an asset based on an assumed level of thermo-economic performance can result in lost opportunities and reduced profits. And while numerous decision support software systems are readily available in the market, these systems often rely on sparse and outdated information to define the performance of a generating asset. The information needed to establish thermodynamic performance is best determined from a first principles model of the power plant cycle where mass and energy are conserved. Such models are used in the early stages of a project to inform the customer of the expected level of asset performance and to size plant equipment. Unfortunately, these original models are not always made available to the customer for use after the plant goes into operation and so hardcopy heat balances, performance test results, or operating data must be used.

COMBINED CYCLE POWER PLANTS

A steam and gas combined cycle in a 1x1x1 configuration is shown in Figure 1. In this cycle, a gas turbine is used to produce electricity and the heat in its exhaust gases is used to generate steam in a heat recovery steam generator (HRSG). The generated steam is then used in a conventional steam turbine-generator for additional plant capacity. The ability to use “waste” heat from the gas turbines increases the overall cycle efficiency substantially above conventional steam cycle plants. Combined cycles also offer operational flexibility: when equipped with a HRSG bypass damper, the gas turbine can be operated in simple cycle mode for quick ramp-up to gas turbine capacity. Supplementary firing of the

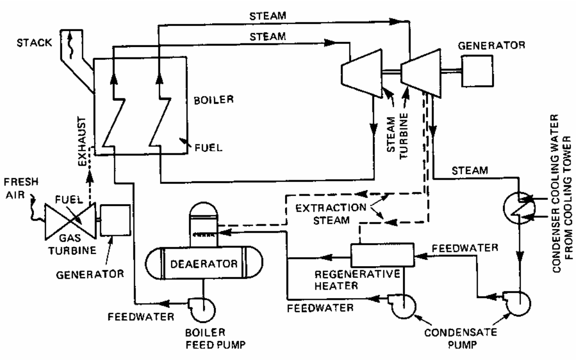


Figure 1. Combined Cycle Power Plant

HRSG with a duct burner can increase steam cycle capacity by 100% or more.

Variation of Heat Rate and Load with Changes in Ambient Conditions

The thermal performance of gas turbine-based power plants are especially sensitive to changes in ambient temperature, where capacity can decline dramatically as air inlet temperature increases. Heat rate increases as air inlet temperature increases. Heat rate characteristics for a typical 1x1x1 combined cycle power plant are shown in Figure 2. The three operating modes are clearly differentiated: simple cycle, combined cycle unfired, and combined cycle fired. For the temperature range considered (60-120 °F), and for the three operating modes, base load plant capacity changes by approximately 24%, 20%, and 14%, respectively. Heat rate variations are less pronounced at 8.4%, 2.7%, and 3%.

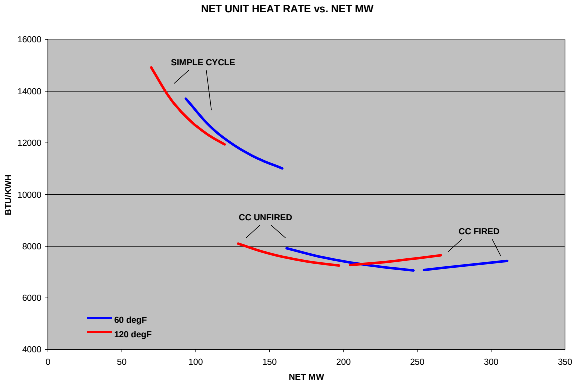


Figure 2. Combined Cycle Heat Rate

Incremental Heat Rate

When determining the most economical unit commitment, an asset's *incremental heat rate* (and cost) is taken into account. The incremental heat rate is defined as the ratio of a change in fuel heat input to the resulting change in electrical output. Engineering units for incremental heat rate are the same as for unit heat rate (Btu/kwh, KJ/kwh), but the meaning is quite different. Incremental heat rate represents the additional heat input required for a given change in unit output. In practice, it is most often represented as the mathematical slope of the input/output relationship, (see Figure 3). For the subject 1x1x1 combined cycle plant, this slope varies substantially with operating mode and with changes in unit load, (see Figure 4). For the temperature range considered (60-120 °F), the incremental heat rate (and thus cost) varies by as much as 1,500 Btu/kwh in simple cycle mode, 750 Btu/kwh in unfired combined cycle mode, and 1,000 Btu/kwh in fired combined cycle mode at *the same load*. With the gas turbine in base load mode, this difference is a consistent 500 Btu/kwh. Unless considered in unit commitment decision support systems, these variations can result in substantial differences in projected profits and the need for excessive end-of-period reconciliations.

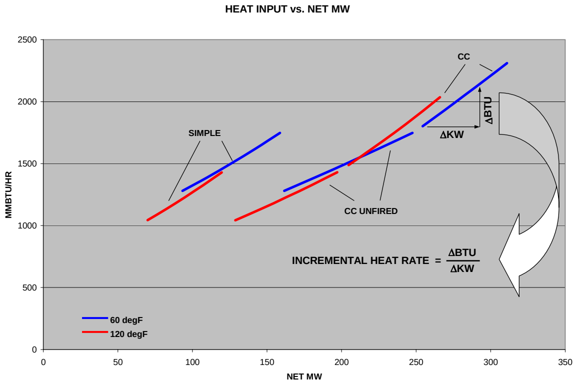


Figure 3. Heat Input/Output

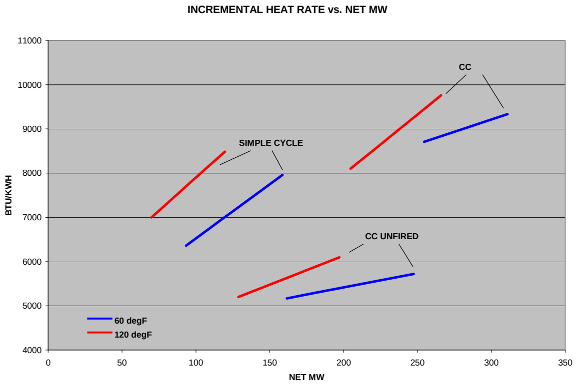


Figure 4. Incremental Heat Rate

Characterizing Unit Performance for Dispatch and Energy Trading

Many companies dispatch their generating assets using curves based on test data corrected to a given reference temperature. Others take the additional step of making seasonal adjustments to improve dispatch accuracy, using different curves for winter, summer, and spring/fall operation. Unfortunately, this practice recovers only a portion of the deviation since actual ambient conditions may vary considerably from those assumed by the curves. A higher resolution model which takes into account actual ambient and equipment conditions has the potential to provide significant improvement over the seasonal approach by providing more accurate upper and lower load limits, as well as incremental costs.

A significant advantage of using a thermodynamic model is that mechanical and process connections are maintained and mass and energy are conserved, (see Figure 5). Such a model, when validated against observed plant performance, can represent "real-world" operating scenarios that differ from original "ideal" test conditions. Examples include operating the gas turbine at a different firing temperature, bypassing a feedwater heater, and running with one cooling water pump at part load. In each of these cases, testing to determine updated capacity and incremental heat rate characteristics is uneconomic and perhaps impossible with reduced personnel resources.

Financial Impact of Improved Model

A study is currently underway by General Physics Corporation and Power Costs, Inc. to evaluate the financial impact of forecasting generating asset performance using a detailed thermodynamic model and comparing it to conventional methods. For this study, the commitment of a typical 1x1x1 combined cycle power plant in the marketplace was modeled during a one week period in March 2003. The detailed thermodynamic model provided updated plant operating load limits and incremental heat rates to match actual ambient conditions. Conventional methods included static load limits and incremental heat rates. Preliminary results show that use of the detailed model improved the accuracy of end-of-period profit estimates by 3 to 15 percent. These early results point to attractive opportunities for improving forecasting of generating costs using detailed thermodynamic models. These broader industry opportunities are being investigated further and will be reported on in an upcoming technical report.

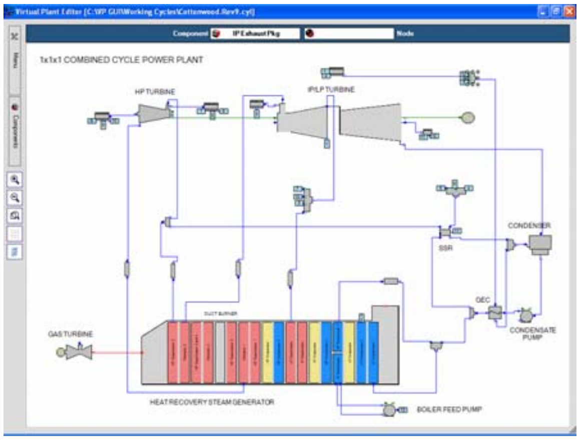


Figure 5. Thermodynamic Model

ENERGY MANAGEMENT SYSTEM

InterGen's Cottonwood Energy Facility is a 1,235 MW natural gas-fired power plant consisting of four (4) identical 1x1x1 combined cycle power blocks. Each block may be operated independently and consists of a General Electric Frame 7FA gas turbine, a three pressure level HRSG with duct firing, and a steam turbine. Construction of the plant began in February 2001, with commercial operation commencing in August 2003. A web-based Energy Management System was implemented by General Physics Corporation to assist plant operators in forecasting plant capacity and part load heat rates and to optimize load distribution among the four power blocks.

The EMS Server (Figure 6) automatically retrieves a 7-day weather service forecast of hourly values for ambient temperature, barometric pressure, and relative humidity. For each hour, the EMS estimates the capacity, part load heat rates, and incremental heat rates of each power block, taking into consideration availability of the evaporative cooler and duct burner, as well as any capacity deratings. The individual block performance forecasts are then combined into a single plant performance forecast of maximum capacity and part load heat rates from minimum plant load (approximately 150 MW) to maximum load (approximately 1200 MW).

The EMS web site provides a common mechanism for communicating plant capability to end-users. A "Weather Forecast" page contains the weather service data used by the model for forecasting hourly capacity and part load heat rates. This information is

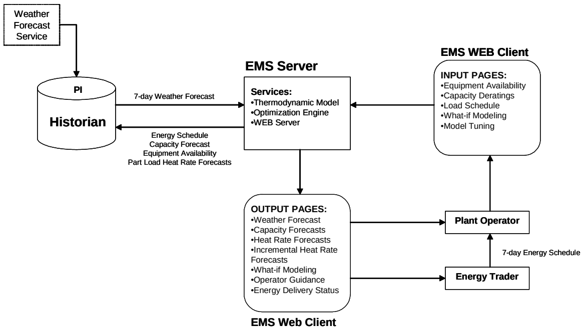
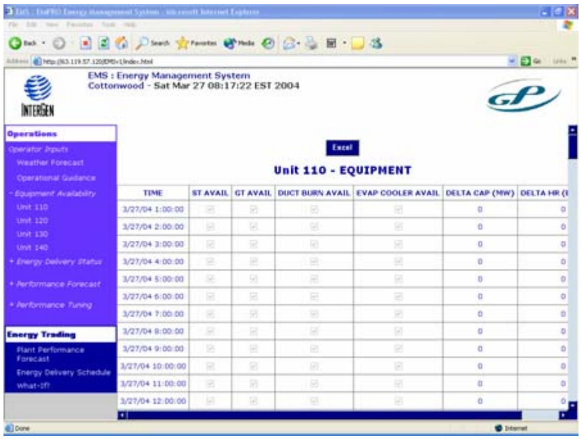


Figure 6. EMS Information Flow

automatically retrieved from the weather forecast service every 4 hours. An "Equipment Availability" page is used by the plant operators to note when the duct burner and evaporative cooler are unavailable (perhaps due to maintenance) and should be excluded from the model. Additional known capacity deratings and heat rate deficiencies are also be entered on this page, (Figure 7). Each time the weather forecast or equipment availability information is changed, the model automatically updates the plant and unit performance forecasts.



EMS : Energy Management System
Cottonwood - Sat Mar 27 08:17:22 EST 2004

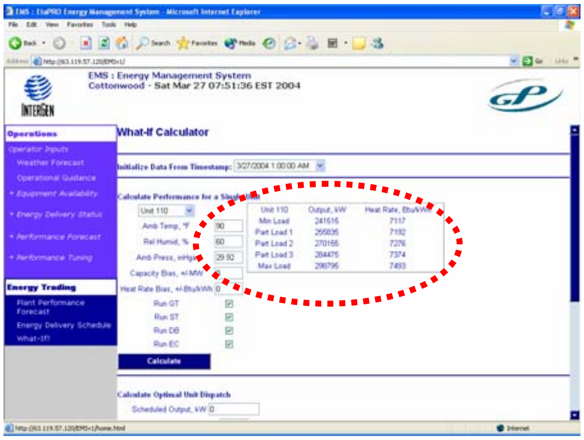
Unit 110 - EQUIPMENT

TIME	ST AVAIL	GT AVAIL	DUCT BURN AVAIL	EVAP COOLER AVAIL	DELTA CAP (MW)	DELTA HR (I
3/27/04 1:00:00	☑	☑	☑	☑	0	0
3/27/04 2:00:00	☑	☑	☑	☑	0	0
3/27/04 3:00:00	☑	☑	☑	☑	0	0
3/27/04 4:00:00	☑	☑	☑	☑	0	0
3/27/04 5:00:00	☑	☑	☑	☑	0	0
3/27/04 6:00:00	☑	☑	☑	☑	0	0
3/27/04 7:00:00	☑	☑	☑	☑	0	0
3/27/04 8:00:00	☑	☑	☑	☑	0	0
3/27/04 9:00:00	☑	☑	☑	☑	0	0
3/27/04 10:00:00	☑	☑	☑	☑	0	0
3/27/04 11:00:00	☑	☑	☑	☑	0	0
3/27/04 12:00:00	☑	☑	☑	☑	0	0

Figure 7. Equipment Availability Page

On-demand Performance Estimates

The "What-if?" page provides a tool for plant operators and energy traders to estimate plant capacity and heat rate for a given set of ambient conditions and equipment availability. Ambient temperature, relative humidity, and barometric pressure are specified by the user. For equipment availability, the gas turbine, steam turbine, duct burner, and evaporative cooler may be specified as being unavailable (perhaps due to maintenance). With these settings, the minimum and maximum capacities are determined, along with a 5-point heat rate profile, (Figure 8).



EMS : Energy Management System
Cottonwood - Sat Mar 27 07:51:36 EST 2004

What-If Calculator

Initialize Data From Timestamp: 3/27/2004 1:00:00 AM

Calculate Performance for a Single Unit

Unit 110
Amb Temp, °F 90
Rel Humid, % 60
Amb Press, inHga 29.92
Capacity Bias, +/-MW 0
Heat Rate Bias, +/-Btu/kWh 0
Run GT ☑
Run ST ☑
Run DB ☑
Run EC ☑

Unit 110	Output, kW	Heat Rate, Btu/kWh
Min Load	241515	7117
Part Load 1	255835	7192
Part Load 2	270155	7276
Part Load 3	284475	7374
Max Load	298795	7493

Calculate Optimal Unit Dispatch

Scheduled Output, kW 0

Figure 8. Block Performance Estimates

Optimizing Power Block Load Distribution

Figure 9 shows plant heat rate for all possible operating scenarios from minimum to maximum load. Because it is possible to achieve a particular part load with multiple operating scenarios, the EMS load optimizer evaluates each scenario to determine the minimum heat rate for each part load point in the 7-day plant performance forecast. The "What-if?" page allows interactive use of the load optimizer to quickly determine the plant configurations that can provide a given plant capacity, along with the resultant heat rates. For example, a plant load of 550,000 KW can be achieved in three operating scenarios: 1) two blocks at base load with duct burners and evaporative coolers, 2) two blocks at base load with duct burners, and 3) three blocks at part load. The heat rates corresponding to these scenarios are: 7,356 Btu/kwh, 7,401 Btu/kwh, and 7,464 Btu/kwh, (Figure 10). The lowest heat rate is achieved with Scenario #1 (two blocks at base load with duct burners and evaporative coolers).

The sensitivity of optimum heat rate to operating scenario can be seen by increasing load from 550,000 KW to 585,000 KW. In this case, the same three operating scenarios apply, but for the new load, the lowest heat rate is achieved with Scenario #3 (three blocks at part load). This information (Figure 11), in combination with the day's load schedule, can be used to optimize block loading for minimum plant heat rate. It should be kept in mind that the relationships on which the optimization is based (Figure 9) must change each time ambient conditions change for a given hour, thereby substantially

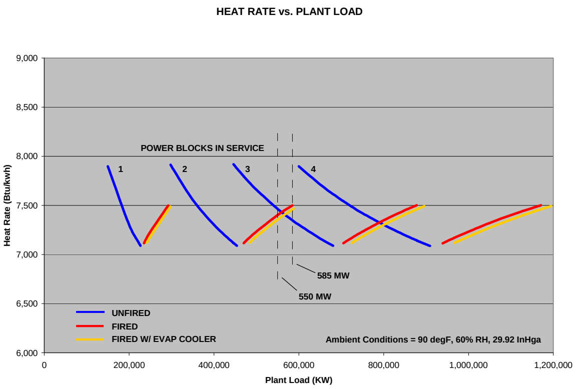
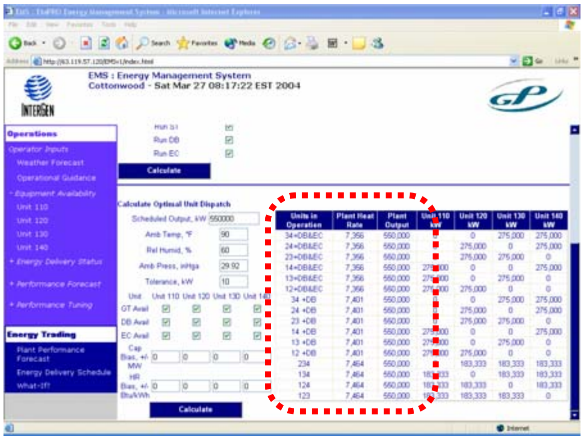


Figure 9. Plant Heat Rate



EMS : Energy Management System
Cottonwood - Sat Mar 27 08:17:22 EST 2004

Run DB ☑
Run EC ☑

Calculate Optimal Unit Dispatch

Scheduled Output, kW 550000
Amb Temp, °F 90
Rel Humid, % 60
Amb Press, inHga 29.92
Tolerance, kW 10

Unit	Unit 110	Unit 120	Unit 130	Unit 140
GT Avail	☑	☑	☑	☑
DB Avail	☑	☑	☑	☑
EC Avail	☑	☑	☑	☑
Cap Bias, +/- MW	0	0	0	0
HR Bias, +/- Btu/kWh	0	0	0	0

Units in Operation	Plant Heat Rate	Plant Output	Unit 110 kW	Unit 120 kW	Unit 130 kW	Unit 140 kW
34+DB&EC	7,356	550,000	0	0	275,000	275,000
24+DB&EC	7,356	550,000	0	275,000	0	275,000
23+DB&EC	7,356	550,000	0	275,000	275,000	0
14+DB&EC	7,356	550,000	275,000	0	0	275,000
13+DB&EC	7,356	550,000	275,000	0	275,000	0
12+DB&EC	7,356	550,000	275,000	275,000	0	0
34 +DB	7,401	550,000	0	0	275,000	275,000
24 +DB	7,401	550,000	0	275,000	0	275,000
23 +DB	7,401	550,000	0	275,000	275,000	0
14 +DB	7,401	550,000	275,000	0	0	275,000
13 +DB	7,401	550,000	275,000	0	275,000	0
12 +DB	7,401	550,000	275,000	275,000	0	0
234	7,464	550,000	0	183,333	183,333	183,333
134	7,464	550,000	183,333	0	183,333	183,333
124	7,464	550,000	183,333	183,333	0	183,333
123	7,464	550,000	183,333	183,333	183,333	0

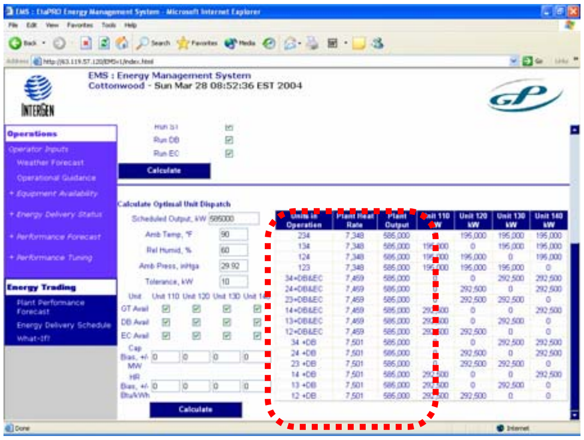
Figure 10. Operating Scenarios for 550 MW

increasing complexity of the optimization mechanism.

Optimizing Load Using a Thermodynamic Model

The load forecast model employed for the Cottonwood EMS was developed using the Virtual Plant™ power cycle modeling program developed by General Physics Corporation. This program is used to develop thermodynamic and hydraulic models of combined cycle and conventional Rankine cycle power plants. The resultant models are rigorous, first-principles engineering models of the power plant cycle and its components; energy and mass are conserved.

The Virtual Plant model is cycled through a range of ambient, load, and equipment conditions to initialize the plant model used in the EMS. The resulting data set is stored in a custom data cube which allows for fast retrieval of the data points. The EMS plant model has variable ambient and load inputs corresponding to the data for each forecast time period and the particular data of interest can be retrieved much more quickly than it would if the Virtual Plant model was exercised each time data was required. Since the data cube is stored in memory, this speed of data retrieval allows the system to try thousands of different operating scenarios within seconds to find an optimal solution.



EMS : Energy Management System
Cottonwood - Sun Mar 28 08:52:36 EST 2004

Run DB ☑
Run EC ☑

Calculate Optimal Unit Dispatch

Scheduled Output, kW 585000
Amb Temp, °F 90
Rel Humid, % 60
Amb Press, inHga 29.92
Tolerance, kW 10

Unit	Unit 110	Unit 120	Unit 130	Unit 140
GT Avail	☑	☑	☑	☑
DB Avail	☑	☑	☑	☑
EC Avail	☑	☑	☑	☑
Cap Bias, +/- MW	0	0	0	0
HR Bias, +/- Btu/kWh	0	0	0	0

Units in Operation	Plant Heat Rate	Plant Output	Unit 110 kW	Unit 120 kW	Unit 130 kW	Unit 140 kW
234	7,348	585,000	0	195,000	195,000	195,000
134	7,348	585,000	195,000	0	195,000	195,000
124	7,348	585,000	195,000	195,000	0	195,000
123	7,348	585,000	195,000	195,000	195,000	0
34+DB&EC	7,459	585,000	0	0	292,500	292,500
24+DB&EC	7,459	585,000	0	292,500	0	292,500
23+DB&EC	7,459	585,000	0	292,500	292,500	0
14+DB&EC	7,459	585,000	292,500	0	0	292,500
13+DB&EC	7,459	585,000	292,500	0	292,500	0
12+DB&EC	7,459	585,000	292,500	292,500	0	0
34 +DB	7,501	585,000	0	0	292,500	292,500
24 +DB	7,501	585,000	0	292,500	0	292,500
23 +DB	7,501	585,000	0	292,500	292,500	0
14 +DB	7,501	585,000	292,500	0	0	292,500
13 +DB	7,501	585,000	292,500	0	292,500	0
12 +DB	7,501	585,000	292,500	292,500	0	0

Figure 11. Operating Scenarios for 585 MW

Optimization calculations occur whenever a change is made to the plant's scheduled energy delivery, weather data, or equipment availability (normally daily). The plant model for each unit is utilized to obtain the input/output curve of the unit over the load range from minimum to maximum load based upon which equipment is available. Given an amount of scheduled energy for the hour, the optimization routine evaluates all possible combinations of units and equipment in service to determine if the plant can be dispatched to meet the required load, and if applicable the amount of process steam. The optimization routines are constrained to follow plant operating procedures such as placing the evaporative cooler and duct burner in service at or near base load and removing the evaporative cooler from service below a pre-set air inlet temperature.

Because of the unique nature of the optimization search algorithm, it is possible to generate multiple solutions for a given scheduled energy delivery. In this case, the EMS ranks the results by the resultant plant heat rates, and selects the block configuration corresponding to the lowest heat rate for input into each block's dispatch (energy delivery status) page. There is also an option to minimize not only heat rate but also starts/stops on each block. If a solution is not found from the performance data for each block, the system user is notified that an optimal solution is not available. While this usually means that the plant cannot run at the scheduled load, it can also mean that the load is beyond the constraints set by the optimization routines.

Field Experience

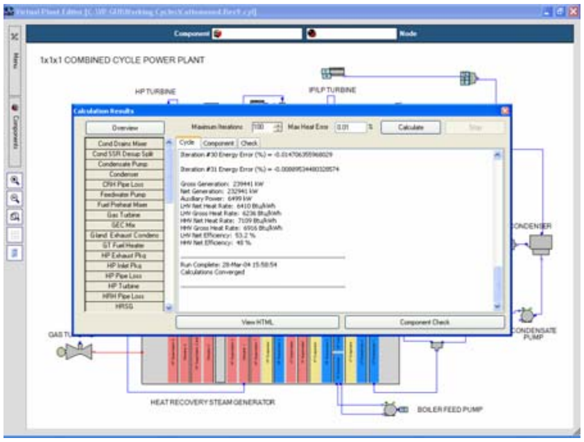
The plant performance forecast is used by the plant operator to report plant capacity and part load heat rates to the energy traders. Each day the load schedule received from the traders is entered into the EMS and the optimum load distribution among the available blocks is calculated and displayed for each hour. The Operating Guidance page of the web site lists the recommended actions to meet the load schedule, such as when to start and shutdown a block and at what load to have it at entering a particular hour.

When initially installed, the EMS was tuned to match the original heat balances and then later tuned to match plant acceptance test results. The tuning of the model in each of these cases was performed by the development team. As the plant capacity and heat rate degraded in the early operating stages due to normal wear-in, it became apparent that a means for the end-user to easily tune the model based on observed performance was necessary to gain the confidence and subsequent acceptance by the plant operating staff. Such a mechanism was added to the EMS in September 2003 and feedback by the plant continues to be very favorable.

VIRTUAL PLANT™ DETAILED THERMODYNAMIC MODEL

The load forecast model employed at the Cottonwood facility was developed using the Virtual Plant™ power cycle modeling program developed by General Physics Corporation. This program is used to develop thermodynamic and hydraulic models of combined cycle and conventional Rankine cycle power plants. The resultant models are rigorous, first-principles engineering models of the power plant cycle and its components; energy and mass are conserved.

The Virtual Plant program operates as a connected system of power plant components, in which the mass and energy balance around each component is satisfied according to the 1st Law of Thermodynamics for steady state operation, (Figures 4 and 12). Calculations proceed iteratively, as each component calculates performance based on the current mass flow, pressure and enthalpy of each steam/water or gas/fuel stream. Once the component has calculated successfully, the component's Heat Output or Heat Input is computed and the procedure moves to the next component in the calculation order. Convergence in the cycle is achieved when the calculated Heat Output is within a certain percentage of the Heat Input. The convergence tolerance can be controlled by the modeler and is typically on the order of 0.01% for a cycle balance with high accuracy. If a component has mass leaving the cycle, such as steam injection into the gas turbine or process steam flow, the cycle will calculate the required amount of water that must be replaced in the cycle (make-up). This water flow is then input into a Makeup Flow component which is connected to the cycle at some logical point in the feedwater or condensate system.



```
Iteration #30 Energy Error (%) = -0.0147063559968029

Iteration #31 Energy Error (%) = -0.00889534480328574

Gross Generation:  239441 kW
Net Generation:  232941 kW
Auxiliary Power:  6499 kW
LHV Net Heat Rate:  6410 Btu/kWh
LHV Gross Heat Rate:  6236 Btu/kWh
HHV Net Heat Rate:  7109 Btu/kWh
HHV Gross Heat Rate:  6916 Btu/kWh
LHV Net Efficiency:  53.2 %
HHV Net Efficiency:  48 %

Run Complete: 28-Mar-04 15:58:54
Calculations Converged
```

Figure 12. Virtual Plant Model Convergence

Gas Turbine Model

There are two methods of modeling a gas turbine in Virtual Plant: 1) predictive gas turbine model, and 2) manufacturer's curves. The predictive gas turbine model is a first principles-based model that simulates gas turbine operation in one of four operating modes – base load, peak load, set load point, or set fuel flow. For part-load operation, the model can be operated with inlet guide vane temperature control to simulate combined cycle applications. The model operates in a manner analogous to the way the actual gas turbine control system operates, i.e., fuel flow is adjusted to control turbine exhaust temperature such that the design firing temperature is not exceeded. Mass and energy are iteratively balanced around the compressor, combustor, and turbine to calculate compressor work, generator output, and energy contained in the exhaust.

Component efficiencies at design conditions are based on manufacturer's data or acceptance test data where available. Where this data is not available, efficiencies can be based on stage loading and technology level of the machine. These can be easily adjusted to tune the model to operating data when it becomes available, or as turbine degrades.

Off-design operating conditions are simulated by a combination of dimensional analysis and component maps. Since component maps are generally highly proprietary information of the manufacturer, these are initially based on the machine design technology and subsequently adjusted based on operating data. The second method of modeling gas turbine performance relies on the manufacturer's design curves. The calculation method used is similar to that in ASME PTC 22[1]. The reference point, which may be at ISO or another design point, contains the design base load data for the gas turbine at a single set of conditions. These conditions include such values as:

- Compressor inlet (temperature, relative humidity, pressure)
- Inlet and exhaust pressure loss
- Fuel heating value and temperature
- Steam or water injection flow
- Fired hours

The design data for the gas turbine includes the following inputs at the rated (base load) or reference condition:

- Net output
- Net heat rate
- Exhaust flow
- Exhaust temperature

A set of curves for each condition modifies the design performance of the gas turbine to the actual measured conditions. These curves correct the performance of the reference point to the measured data individually, and the total correction is then either multiplied or added to the base rating. Corrections for output, heat rate, and exhaust flow are multiplicative, while corrections for exhaust temperature are additive.

The curves required for this method are typically obtained from the manufacturer, usually as part of the performance test procedure. Often the curves are updated prior to testing to account for changes in DLN tuning which may affect performance. Some correction curves are functions of only a single variable, such as compressor inlet temperature, while others such as relative humidity are dependent upon two variables.

The operating condition of the gas turbine is modified to match the actual operation of the unit. The operating mode may be selected as either Base Load or Part Load. For base load, the gas turbine calculates the expected output, heat rate, exhaust flow and exhaust temperature from the known base load firing curve data. In part load operation, the required power output is set by the user (subject to operating range constraints), and the heat rate and exhaust flow and temperature are calculated. Minimum load may be based upon emissions limits, stable operation, etc. The gas turbine may also be bypassed by clicking the gas turbine online checkbox, which simulates a gas turbine shutdown.

Other parameters which may be modified to match actual operation are the natural gas fuel analysis and the fuel temperature. Fuel temperature is especially critical if a fuel gas heater is in operation due to the sensible heating effects of the fuel temperature on plant heat rate. The inlet and exhaust pressure loss should be set to match operating data as these also affect the gas turbine corrections. Finally, the operation of the evaporative cooler or fogger may be modified or shut off. If an evaporative cooler is in service, the effectiveness may be changed from the default of 85%. If a fogger is in service, the control temperature difference above the wet bulb may be modified from the default of 2°F. The minimum ambient temperature for evaporative cooler or fogger operation is also set. Minimum temperature requirements are based upon the manufacturer's anti-icing requirements, and will vary with ambient relative humidity.

Heat Recovery Steam Generator (HRSG) Model

The HRSG model predicts the heat transfer and hydraulic response of each economizer, evaporative and superheater stage due to energies supplied by gas turbine and duct burners (as applicable). Using the effectiveness-NTU method, superheater steam flows, steam conditions, duct gas temperatures, attemperation sprays, pinch point and approach temperatures are predicted and used in the model of overall plant performance.

The HRSG is a single component in the Virtual Plant model, with multiple gas path components specified for each pressure level. These components are laid out in the same logical fashion as the HRSG manufacturer's design data sheets. The types of components available are:

---

[1] ASME PTC 22 -1997, *Performance Test Code on Gas Turbines*

- Superheater
- Evaporator
- Evaporator with integral Deaerator
- Economizer
- Duct Burner

The type, pressure level, and description are defined for each heat transfer component. If the component is in parallel with a previous component this may be selected along with the fixed percentage of exhaust gas flow.

Additionally, superheater attemperation sprays, mixers, splitters, recirculation, and bypasses may be inserted into the steam/water path. This allows for desuperheating of steam, mixing or splitting steam or water to and from an external source, recirculating feedwater to maintain stack temperatures, or bypassing feedwater around economizers.

The design data (inlet and outlet pressure and enthalpy, and the steam or water flow) for each gas path component is entered into the model to define its heat transfer performance at design conditions, The design exhaust gas flow, gas temperature, and duct burner flow rate are also entered, as well as the design flue gas constituents and the duct burner fuel analysis.

Once all design data are entered, the HRSG model calculates the design UA for each gas path component. The component's heat capacity rate ("C") for both the gas side and the water side are calculated, which is the flow rate multiplied by the average gas or water specific heat for the component section. The minimum heat capacity rate ("C_{min}") is determined from both gas and water side inputs. The design heat input ("Q") to the water side is also calculated from the design pressures, flows and enthalpies entered previously.

The equation for effectiveness for a cross flow (unmixed) heat exchanger is defined as[2]:

$$\varepsilon = 1 - \exp\left[\frac{1}{C_R} \cdot NTU^{0.22} \cdot \left(\exp\left(-C_R \cdot NTU^{0.78} \right) - 1 \right) \right]$$

Where ε is effectiveness, C_R is the ratio of the heat capacity rates, and NTU is the number of transfer units. Using the bisection method, the NTU of the gas path component is solved for iteratively. The governing equation relating heat transfer and effectiveness is defined as[3]:

$$Q = \varepsilon \cdot C_{Min} \cdot \left(T_{hot,in} - T_{cold,in} \right)$$

Where Q is the heat transfer, C_{Min} is the minimum heat capacity, and $T_{hot,in}$ and $T_{cold,in}$ are the inlet temperatures of the gas and water side respectively. The bisection method iteratively solves the two equations with two unknowns (effectiveness and NTU). Once the NTU is known, the UA of the heat exchanger is calculated by the relationship[4]:

$$UA = NTU \cdot C_{Min}$$

Where U is the overall heat transfer coefficient, and A is the effective surface area. Once the design UA of the component is known the value is scaled up or down to calculate the heat transfer for off-design conditions. This empirical relationship of design UA to off-design UA is defined as[5]:

$$\frac{UA_{act}}{UA_{des}} = \left(\frac{k_{act}}{k_{des}} \right)^{2/3} \cdot \left(\frac{W_{act}}{W_{des}} \right)^{m} \cdot \left(\frac{\mu_{act}}{\mu_{des}} \right)^{2/3} \left(\frac{c_{p,act}}{c_{p,des}} \right)^{1/3}$$

Where k is the thermal conductivity of the exhaust gas, W is the exhaust gas flow rate, m is the flow scaling factor (default of 0.8), μ is the viscosity and c_p is the specific heat. All values in the above equation are known and based on the current iteration data with the exception of UA_{act}. Once the current value of UA is calculated the NTU and effectiveness can be solved, and the heat transfer to the component is finally calculated using the above relationships.

This process continues for each component in the exhaust gas path until all components have been calculated. The HRSG calculation is repeated iteratively until the outlet flows and outlet enthalpies have converged.

HRSG efficiency is calculated per the input/output method specified in ASME PTC 4.4[6]. The net heat output of the steam and feedwater is divided by the net heat input of the gas turbine exhaust, which results in the efficiency.

---

[2] Incropera & DeWitt, *Fundamentals of Heat and Mass Transfer 2nd Edition*, p. 523

[3] Incropera & DeWitt, p. 521

[4] Incropera & DeWitt, p. 521

[5] Incropera & DeWitt, Chapter 7 External Flow

[6] ASME PTC 4.4-1981 (Reaffirmed 1987), *Gas Turbine Heat Recovery Steam Generators*

Steam Turbine Model

The steam turbine model calculates turbine efficiencies using the industry-standard ASME publication "A Method for Predicting the Performance of Steam Turbine-Generators 16,500 KW and Larger"[7]. This method allows turbine expansion lines to be accurately determined over the load range, and if greater accuracy is needed, adjustment factors can be inserted by the user to match original design performance or include the impact of degradation. Actual efficiency and exhaust loss curves may also be used rather than the default set of curves from the ASME paper.

The steam turbine model consists of two separate components, a high-pressure (HP) section and an intermediate/low (IP/LP) pressure section. The HP section contains information to model the throttle, first-stage nozzle, extractions and exhaust of the turbine with nodes for connecting to inlet and exhaust leakages. The IP/LP section models the IP inlet, extractions, and the steam turbine exhaust losses. This separation of sections allows for modeling of a typical tandem or cross-compound reheat steam turbine with multiple exhaust planes. Non-reheat steam turbines are supported as well.

Other components such as pumps, condensers, cooling towers, feedwater heaters, and fossil boilers are modeled in similar detail using industry-standard techniques.

NEXT STEPS

The system described in this paper has been installed at the Cottonwood, Magnolia, and Redbud facilities (US) and will be rolled out to the Rijnmond (the Netherlands) and Spalding (UK) Energy facilities in Spring 2004. The system has provided the plant with a consistent means of accurately forecasting plant performance and communicating these results to the energy trading floor. Next steps being considered are tying the EMS model directly into the unit commitment software used by the regional trading organizations.

CONCLUSIONS

1. A reliable approach has been developed and implemented for incorporating high resolution thermodynamic models in real-time systems for forecasting plant capacity, heat rate, and incremental heat rate.
2. Incorporating real-time thermodynamic models in place of simplified curves for unit commitment has the potential for substantial improvement in overall dispatch accuracy and profitability.
3. A web-based front-end for accessing real-time forecasts and for performing ad-hoc "what-if" evaluations has proven to be very successful in field use.
4. A unique algorithm for high speed evaluation of alternative operating scenarios for selecting plant arrangements leading to minimum heat rate has been developed and successfully implemented.
5. Potential improvements in dispatch accuracy on the order of 3% to 15% demonstrate the viability of incorporating real-time thermodynamic models in unit commitment decision support systems and point to the need for additional research.

ACKNOWLEDGEMENTS

The authors would like to thank EMS development team members Shawn Whitecar and Ross Brodbeck for their contributions to this paper. The authors would also like to express their appreciation to Wayne Whitehead of the Cottonwood Energy Facility for his continued support and valuable feedback.

---

[7] Spencer, Cotton & Cannon, *A Method for Predicting the Performance of Steam Turbine-Generators 16,500 kW and Larger*, Revised 1974, Based on ASME Paper No. 62-WA-209

Leading the World to Better Performance

GENERAL PHYSICS CORPORATION
25 Northpointe Parkway • Suite 100
Amherst NY • USA
Phone 716.691.1212 • Fax 716.691.0755
www.etapro.com