

*A Case Study about Profit Maximization*

# 10 MWe Combined Cycle Gas Turbine Cogen Plant

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Clear and present market signals increase economic efficiency and bring environmental and social benefits. Market signals that lack these qualities will be poorly understood and infrequently applied. One year of operation of a combined cycle gas turbine cogeneration plant in the 10 Megawatt electric (MWe) class serves as a case study. The author applies a new index of economic efficiency called the “profit maximization factor” in order to quantify plant performance. Recommendations are made to benefit cogeneration plant manufacturers, owners, operators, regulators, utilities, and environmentalists.

## PLANT DESCRIPTION

The 12.75 MWe (gross) combined cycle plant consists of two gas turbines, two heat recovery steam generators, two auxiliary boilers, one steam turbine, and the associated systems. Gas turbines are rated at 4.75 MWe each. A natural gas-fired heat recovery steam generator (HRSG) is dedicated to each gas turbine. Each train includes an auxiliary boiler and delivers steam to a single steam turbine generator (STG) rated at 3.25 MWe. The net electrical production is approximately 11.5 MWe. The plant characteristics are summarized in Table 1.

**Table 1. Characteristics of Plant<sup>1</sup>**

C.O.D.	Dec. 1997
Engines	2X Gas Turbine
Mfr./Model	Solar Taurus 60
Cycle	Brayton
Fuel	Natural gas or fuel oil
HRSGs	2X 32,000 lb/hr
Aux. boilers	2X 90,000 lb/hr
Cost (\$/kW)	(confidential)
MWe (gross)	12.755
MWe (net)	11.500
Fuel flow	2,050 therm/hr (HHV)
Heat recovery	1,129 therm/hr (HHV)
Plant Heat rate	14,468 Btu/kWh (LHV)
Electrical efficiency	0.2124 (HHV)
Thermal efficiency	0.5510 (HHV)
Combined eff.	0.7634 (HHV)
Generator(s)	4,160V synchronous

## PLANT OPERATION

The plant serves a university campus with 24-hour electrical and thermal loads. The gas turbines are operated as baseload capacity and produce some steam without additional firing of the HRSGs. When steam demand exceeds that level, the HRSGs are fired to satisfy it. Electrical demand that exceeds generation is purchased from the grid at Pacific Gas & Electric's E-20P tariff. Generation in excess of site demand is sold back to the grid at ex-post ISO (Independent System Operator) rates.

## PLANT PERFORMANCE

Performance is contractually evaluated on the basis of plant availability and a guaranteed heat rate. The staff keeps a detailed history of plant operations. Tariff E-20 is a large commercial rate schedule with

time-of-day pricing. Therefore costs and benefits need to be examined on a time-of-day basis to get a meaningful result. The hourly and seasonal variables are (1) the avoided cost value of thermal and electrical power production usefully supplied to the campus, (2) the cost of purchased electricity and natural gas fuel, and (3) the value of excess electrical or thermal production, if any.

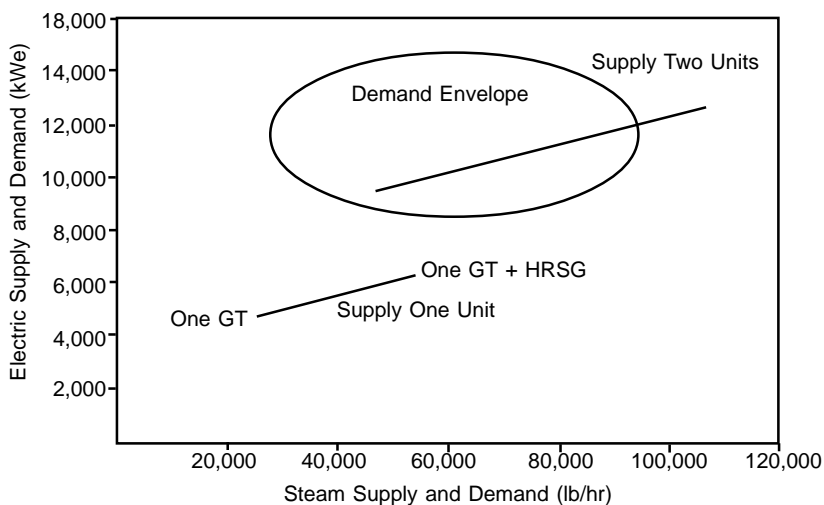
The campus thermal and electrical demands are favorable for cogeneration, but they are not the exact quantities of heat and power available from any particular powerplant. Figure 1 shows possible combinations of thermal and electrical supply and demand on the major axes. The characteristics of the combined cycle plant can be represented as a set of curves analogous to pump curves or fan curves. The plant "curves"—actually straight lines—start out with each gas turbine (GT) operated at full electrical load. The extensions represent gas firing of the HRSGs, additional steam, and electrical output from the steam turbine-generator (STG). Superimposed on these lines is an envelope of combinations of campus thermal and electrical demands.

From Figure 1 can be seen the outlines of the plant operation. Demand combinations inside the envelope and above the two-unit operating curve can be satisfied in two ways: either by supplying exactly the thermal demand and purchasing additional electricity or by supplying exactly the electrical demand and condensing or wasting the excess low-pressure steam.

Points inside the envelope and below the operating line denote the complementary conditions. Following thermal demand will result in excess electricity supply that can be sold back to the grid. Following electrical demand will result in a shortfall of steam supply to be made up by conventional boilers.

Demand is not random within the envelope, but more of a normal distribution along both axes. Points on the perimeter represent conditions that occur only once a year.

The plant is operated at all times to follow the thermal demand. Controls and instrumentation maintain a constant 15 psig at the steam turbine exit by regulating the HRSG firing rate. This philosophy is logical in that thermal demand is met from the cogeneration plant at all times. Electrical demand is not completely supplied by the plant, but most of it is. Electric purchase takes place mostly on peak and electric sales off peak.



**Figure 1. Demand Envelope and Supply Curves**

#### CASE STUDY—1999

Several indices are available and helpful in quantifying plant performance. Table 2 introduces the *profit maximization factor* analogous to load factor and capacity factor. Profit max factor is defined as the profit earned by the plant relative to the best possible outcome given the plant specifications.

**Table 2. Plant Performance Indicators for 1999**

Gas Turbines' Availability	0.991
Central Plant Availability	0.977
Capacity Factor	0.735
Profit Max Factor	0.828

From Table 2 can be seen the result of concentration on availability. Certainly reliability is good, but inattention to additional market signals resulted in failure to realize the best value of the central plant. Capacity factor is lower because the decision to follow thermal demand does not make full use of the steam turbine capacity. Profit maximization factor

is calculated only after the actual and ideal cases are determined, but it is shown in Table 2 for clarity. What will be found is that the plant made 83% of the profit that it could have made in 1999.

Table 3 presents the optimal economic performance, given the same plant technical performance. The detailed analysis has shown that the cost of electricity for peak and mid-peak periods is high enough to justify following electrical demand even if it means condensing or venting excess steam. For a modest increase in capacity factor, about five percent, the economic reward can be increased by approximately 20 percent.<sup>2</sup> This potential improvement in profit of \$500,000 from the central utilities plant is a reward for working both smarter and harder. Note that the max factor is not supposed to be a standard of perfection. It is just a tool, another way to understand the data.

**Table 3. Optimal Performance Indicators**

Gas Turbines' Availability	same
Central Plant Availability	same
Capacity Factor	0.787
Profit Max Factor	1.000

The calculations necessary to move from Table 2 to Table 3, optimized performance indicators, do not require more than the four math functions. Appendix 1 shows the outline of the method. Each cost or benefit is quantified by time-of-day period. Therefore each cost or benefit has an array of five data.<sup>3</sup> When these data are expressed in common units of dollars per kWh, two alternatives can be compared by summing the costs and benefits of each.

It may turn out that an alternative is the better choice in the time-of-day period and a poorer choice in another. That is exactly the purpose of the exercise. To quantify an annual cost or benefit, the base case is determined by multiplying the actual values in the Appendix 1 matrix by another matrix of kWh per year. The product is a third matrix of dollars per year. The same procedure is repeated for the alternative case(s) and values. The better alternative is identified on a time-of-day basis.

For this case study, this procedure made clear that it was more efficient (made more profit) in all seasons to follow the electrical demand

on peak and part-peak; conversely, it was more efficient to follow thermal demand off-peak, both winter and summer.<sup>4</sup>

As mentioned above, a real plant will not make 100% of any index all of the time, but it shows the right direction to go. This proposed alternative would require additional condenser capacity to avoid venting steam. As an experimental step, staff could implement the operating strategy up to the capacity of the existing dump condenser. Even this 12,000 pounds per hour of steam turbine capacity would make a substantial reduction in summer electric charges.

Future plans for the central plant include absorption chillers that will use steam. This new chiller capacity will not reduce existing electrical demand, however. On-going plant improvements make this a favorable time to optimize the plant design and operation.

#### ANOTHER EXAMPLE OF THE METHOD

The plant operator proposed the addition of a cooling coil in the combustion air to increase power from the gas turbines. Cooler combustion air results in more power from the same engine. The question is whether the relatively cool climate of the area is hot enough to make the measure pay back. When evaluated with weather data and the average cost of power (see Appendix 1, Matrix B for rates) the measure has a long payback. When evaluated on a time-of-day basis, on-peak operation would be sufficient to yield a three-year payback. In this case higher ambient temperatures and lower gas turbine output coincide with peak demand on the campus and peak electric rates. A final decision has not been made at this writing.

#### “PROFIT MAX FACTOR”

The profit maximization or “max” factor seeks to recognize market signals in the form of variable costs. These variable costs mentioned on the first page are (1) value of production used on site, (2) cost of purchased utilities, and (3) the value of excess production. A more basic description of the max factor and several examples may be found in the Spring, 2000 issue of the *Cogeneration and Competitive Power Journal* (Vol. 15, No. 2, pp 37-50).<sup>5</sup> That study found that cogeneration plant owners

in the 100 kW and 1 MW classes had a similar failure to react to market signals in the form of time-of-day rates.

Energy prices during 1999 varied on an hourly basis for purchase and for sale of electricity. These were tabulated on an hourly basis and recombined into time-of-day periods for retrospective analysis. Additional value of this method would lie in applying it to day-ahead scheduling decisions. Time-of-day prices for natural gas have recently been proposed and approved in some markets.

An unexpected finding was the degree to which market signals are incompletely appreciated in this class of power plant. For example, electricity purchased on-peak for the six summer months of 1999 averaged \$0.25 per kWh in demand and energy charges. The reader can be forgiven for thinking that there must be some mistake in the analysis. When a reliable periodical reports that the utility's commercial rate is \$0.0780 per kWh<sup>6</sup>, it has to be true.

The explanation of the difference is that the smaller number is an average of averages and it applies to a user with a large account and a good load factor. There are necessarily some customers doing better and some others doing worse than the average. Fortunate customers can do a little better, but the unfortunate can do much worse. This theme leads to a discussion of how to think about electric rates.

#### ELECTRIC RATES: COMMON MISTAKES TO BE AVOIDED

These common mistakes come under the category of failure to become familiar with and understand the rate schedule. Most of the terms pertain to the Pacific Gas and Electric tariffs and service area but other utilities use similar structures.

#### **Reservation Charge**

Independent generators who rely on a utility to provide alternative source of power must pay a "reservation charge." Even if the capacity is not used during the month, the user has realized the insurance value. This reservation charge should be considered a fixed cost. It need not and should not be included in the calculation of a site's energy cost per kWh.

### **Standby Credit**

A familiar misconception is that the “standby credit” clause will return to the user a demand charge incurred for an outage. Like most good mistakes, it has some part of the truth in it. As of early 2000 the standby credit will return 85 percent of one of the three components of demand charge, namely the “maximum demand charge.” Thus an off-peak outage will incur only the maximum demand charge—the smallest of the three, by the way—and 85 percent of it will be refunded. An outage during so-called “part-peak” or on-peak will result in substantial charges that are not refunded.

### **Rate Limiter**

Another misconception is that unusually high electric charges will be avoided by the “rate limiter” clause. Again there is some truth in it. What the rate limiter will do is limit the *average* total cost per kWh to \$0.14. On-peak rates—i.e., before they are weighted and averaged with off-peak hours—can and do reach \$0.27 and \$0.28 per kWh without actuating the rate limiter. Thus, it provides a false sense of security because the on-peak rate is already out of control by the time the rate limiter is invoked.

## RECOMMENDATIONS FOR REACHING PROFIT MAXIMIZATION

### **For the Plant**

Consider operating the plant to follow electrical demand on part-peak and especially on-peak during the summer months. Continue to follow thermal demand during off-peak operation. Pursue conservation and peak shaving measures; value the savings at the true marginal cost. Schedule planned maintenance off peak and major plant improvements for the winter months. Incorporate the profit max factor into regular reporting cycles and “conserve money.”

### **For Cogeneration Plant Buyers and Operators**

The best thermodynamics need to be matched with the best financial analysis because common sense may or may not accord with market signals. In other words, time-of-day rates can surprise you.

### **For Cogeneration Plant Suppliers**

Recognize that market signals affect plant economics and that users of the 10 MW class are not likely to respond to them. Offering this simple analysis as a value added option could be the feature that puts your proposal into first place.

### **For Regulated Utilities**

Acknowledge that there is a good reason why generators smaller than the merchant class do not respond to market signals: those signals are complicated and difficult to track. Rate schedules are frequently unclear even to specialists. The monthly electric detail could easily spell out the customer's average price by time-of-day interval and encourage the appropriate response.

### **For State Regulatory Staff**

See preceding paragraph. Small and medium-sized market participants receive incomplete information. Their inability to respond to signals indicates a market failure. Terms and definitions used in rate schedules are often ambiguous or hard to find.

### **For Environmentalists**

See preceding two paragraphs. Cogeneration can reduce the use of fossil fuels by improving efficiency. Market signals can also improve efficiency and reduce pollution but only if they are clear and accessible to facility managers.

**Plant owners and operators up to and including the ten Megawatt class fail to recognize market signals in the form of time-of-day rates. This failure leads to an inefficient market, unfavorable environmental impacts, and construction of additional capacity. Recommendations for each of the parties are identified.**

### **Endnotes**

<sup>1</sup>In design documents the plant heat balance and guaranteed heat rate are given in lower heating value (LHV). Most of these have been converted to higher heating value (HRV) for clarity in Table 1.

<sup>2</sup>This increase from 83 to 100 percent corresponds to 17 parts in 83, thus something more than the nominal 17 percent improvement.

<sup>3</sup>There would be six cells in each array if the winter peak rate were

unique, but it is identical to winter part-peak rate. One cell per array is shaded as a reminder.

<sup>4</sup>For utilities there are only two annual seasons in gas and electric rates, each six months long.

<sup>5</sup>Dietrich David, et al., "Case Studies of Small Cogeneration" originally appeared as a paper published in the "Proceedings" of the 22nd AEE World Energy Engineering Conference, Atlanta, Georgia, October 22, 1999, pp. 323-327.

<sup>6</sup>*Energy User News*, **24**, 8, August 1999, p. 36.

<sup>7</sup>Manuscript dated March 31, 2000, presented at the West Coast Energy Management Congress, San Jose, California, June 22, 2000.

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#### ABOUT THE AUTHOR

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Appendix 1 Matrix of Selected Financial Inputs

**ACTUAL**

TOD	\$/kWh summer	\$/kWh winter
<b>A</b>	S	W
PK	0.15492	
PP	0.06885	
OP	0.04980	
ave	0.07279	0.05436

**A** is the value of the electricity generated and used on site. Avoided cost of E-20P.

weighted

TOD	\$/kWh summer	\$/kWh winter
<b>B</b>	S	W
PK	0.24599	
PP	0.09663	
OP	0.05308	
ave	0.13612	0.10006

**B** is the cost of the electricity purchased above generation. Actual E-20P.

weighted

TOD	\$/kWh summer	\$/kWh winter
<b>C</b>	S	W
PK	0.03138	
PP	0.03095	
OP	0.01837	
ave	0.01902	0.02090

**C** is the value of the excess electricity resold to the grid. Actual ex-post ISO.

sales predominantly off-peak (-Ed.)  
weighted averages correct (-Ed.)

TOD	\$/kWh summer	\$/kWh winter
<b>D</b>	S	W
PK	0.05253	
PP	0.03969	
OP	0.02643	
ave	0.03591	0.02116

**D** is the value of excess electricity if resold to the grid at a constant level.

**Blank for Readers**

TOD	\$/kWh summer	\$/kWh winter
<b>A</b>	S	W
PK		
PP		
OP		

TOD	\$/kWh summer	\$/kWh winter
<b>B</b>	S	W
PK		
PP		
OP		

TOD	\$/kWh summer	\$/kWh winter
<b>C</b>	S	W
PK		
PP		
OP		

TOD	\$/kWh summer	\$/kWh winter
<b>D</b>	S	W
PK		
PP		
OP		

G2 is the natural gas cost to generate power in \$/kWh.

G2	S	W
PK	0.04138	gas\$/kWh
PP	0.04138	0.03964
OP	0.04138	0.03964

G2	S	W
PK		gas\$/kWh
PP		gas\$/kWh
OP		gas\$/kWh

H2 is the value of the natural gas cost recovered as steam from waste heat expressed as gas \$/kWh electric.

H2	S	W
PK	0.02850	gas\$/kWh
PP	0.02850	0.02730
OP	0.02850	0.02730

H2	S	W
PK		gas\$/kWh
PP		gas\$/kWh
OP		gas\$/kWh

L is the worst case cost of water if used to generate electricity and discarded in water\$/kWh.

L	S	W
PK	0.01922	water\$/kWh
PP	0.01922	0.01922
OP	0.01922	0.01922

L	S	W
PK		water\$/kWh
PP		water\$/kWh
OP		water\$/kWh

P is the cost of steam from an 80% eff. conventional boiler in units of \$/kWh not generated.

P	S	W
PK	0.01959	gas\$/kWh
PP	0.01959	0.01877
OP	0.01959	0.01877

P	S	W
PK		\$/lbm
PP		\$/lbm
OP		\$/lbm

T is the cost of maintenance in \$/kWh. (estimated)

T	S	W
PK	0.00700	\$/kWh
PP	0.00700	0.00700
OP	0.00700	0.00700

T	S	W
PK		\$/kWh
PP		\$/kWh
OP		\$/kWh

Legend  
Time-of-day intervals

PK Peak (summer only)  
PP Part-Peak  
OP Off-Peak