How operating constraints impact the value of combined-cycle plants

By **Jason Kram, Doug Logan,** and **Nish Dagli,** PCI

With an abundance of relatively similar generation capacity up for sale, accurately determining the value of a given unit may involve consideration of its operational constraints. For example, many new combined-cycle plants are nearly identical in design, but often there is enough technical variation to distinguish them individually. Due diligence teams with the proper analytical tools find that operational constraints may impact the total value of a given combined cycle by as much as 30%.

As generation assets and the companies that own them come under distress, the valuation of these assets is being done with increasing rigor. Sellers want to be able to distinguish their particular assets above the rest and buyers want to identify the best assets for their investment. By modeling the operating complexities and constraints of a combined-cycle asset, impact of those constraints on value when participating in market-based operations can be identified. In addition, asset owners can determine where to best invest their capital dollars for unit improvements that would relieve one or more of the operational constraints.

There are many considerations when valuing generation assets. Among some of the more prominent characteristics include physical location, market liquidity, transmission, and a host of operational considerations with efficiency (heat rate) and output receiving the most attention. The focus of this analysis is to consider the operational characteristics and the impact that they have on value.

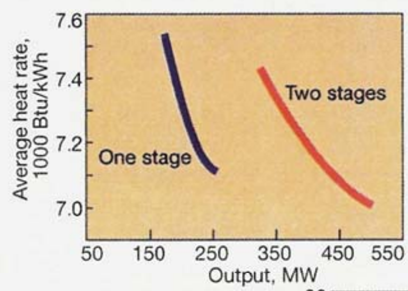
The following unit constraints were analyzed to quantify their impact on operating gross margin:

- Lower operating limit (LOL)
- Higher operating limit (HOL)
- Minimum uptime and downtime
- Ramp rate
- Number of starts
- Heat rate
- Startup profile

The plant analyzed was a natural-gas-fired combined-cycle unit consisting of two gas turbine/generators (GTs), two heat-recovery steam generators (HRSGs), and one steam turbine/generator (ST). The plant cannot operate in the simple-cycle mode but may run in a one-on-one configuration with one GT (and its associated HRSG, together referred to as a "stage") and the ST producing power.

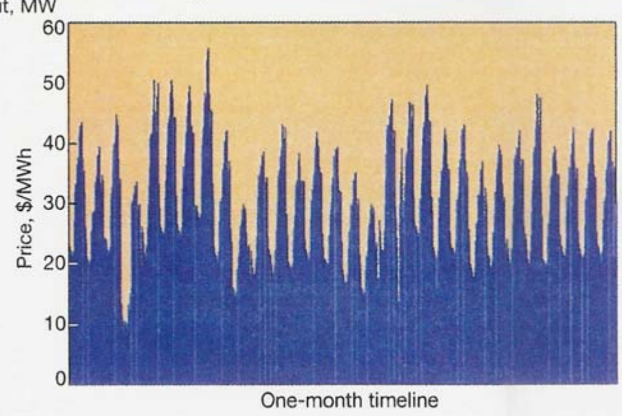
The combined cycle's operating range was from 175 to 500 MW. As shown in Fig 1, the average heat rate ranges from slightly over 7500 Btu/kWh at the lower operating limit to approximately 7000 Btu/kWh at the higher operating limit. For this analysis, the unit was assumed to have an eight-hour uptime and downtime constraint, a ramp rate of 3 MW/min, and no startup profile. The uptime constraint means that once the plant starts operating, it must continue to do so for at least eight hours. Likewise, it must remain out of service a minimum of eight hours after each shutdown.

The energy price forecasts presented in Fig 2 are modeled after actual hourly power prices. In this one-month example, on-peak power prices vary hourly and range from $10 to $56/MWh—averaging around $36/MWh. Off-peak prices vary hourly and average around $22/MWh for the month. The gas price was constant for the one-month period at $3.77/million Btu.

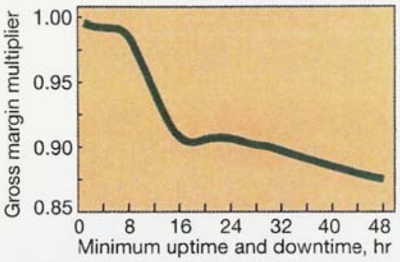


1. Top efficiency of a two-on-one combined-cycle unit is achieved when both gas turbines are operating (left)

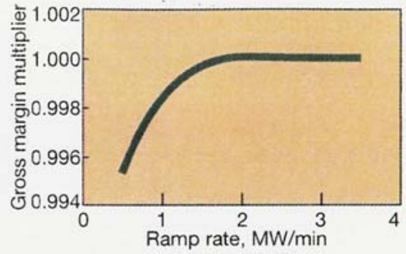
2. Energy price forecasts for a one-month period are modeled after actual power prices. On-peak hourly prices vary between $10 and $56/MWh



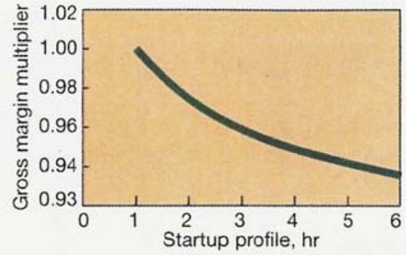
Under the assumed market conditions and unit constraints described above, we optimally commit and dispatch the unit to measure its operating gross margin. Then, we stress each of the unit constraints to measure their impact under the same market conditions. Results



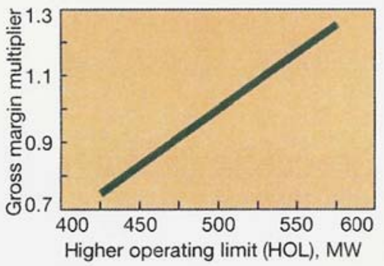
3. Impact of minimum uptime and downtime relative to the baseline case shows a dramatic drop in gross margin multiplier between eight and 16 hours



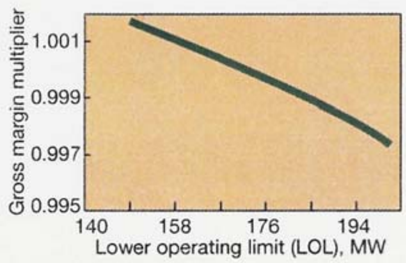
4. Impact of ramp rate on gross margin is negligible compared to other operating constraints



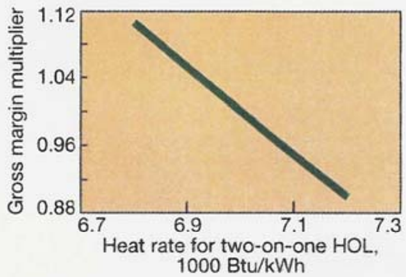
5. Startup profile can impact gross margin, relative to the baseline case, by more than 6% in the most restrictive scenario shown (six-hour startup)



6. Relatively small changes in HOL significantly impact gross margin. Note that if the HOL were to drop by 15% gross margin would plummet 25%



7. Changes to LOL, like ramp rate (Fig 4), have relatively little impact on the baseline gross margin—that is, until unit operating flexibility is compromised

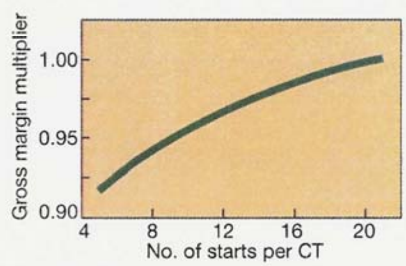


8. Increasing/decreasing the heat rate by 3% at the HOL can decrease/increase the gross margin by 11%, relative to the baseline

of the analysis are presented in terms of relative change in gross margin as compared to the baseline gross margin.

Figs 3 through 9 show each individual constraint's relative impact on the baseline gross margin. Fig 10 shows all the constraints and relative gross margin impact in one diagram.

As expected, small changes in HOL (Fig 6) and heat rate (Fig 8) significantly impact gross margin. For example, increasing/decreasing the HOL by 15% can increase/decrease the gross margin relative to the baseline by nearly 25%. This is because the HOL determines the number of megawatt-hours produced when power prices are highest. Increasing/decreasing the heat rate at the HOL by 3% can decrease/increase the gross margin relative to the baseline by nearly 11%. Reason: This parameter determines the margin in dollars per megawatt-hour when the plant is at its highest output. Bear in mind that these parameters can vary significantly with plant design. Plus, both also vary with changing ambient weather conditions, making careful approximation of these operating characteristics important in plant-valuation and capital-improvement projects.

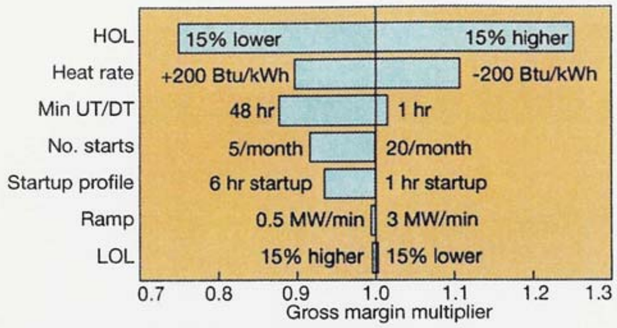


9. Maximum gross margin is reached at 21 starts, the number of weekdays in the month, under the assumed market conditions. Additional operating flexibility adds little value

Operating flexibility is increasingly important when a particular unit is running at or near its generation cost. Some constraints that dictate operating flexibility, whether imposed by equipment design or contractual obligations, are the minimum uptime and downtime (Fig 3), startup profile (Fig 5), and number of starts (Fig 9). As shown in the figures, each one of these constraints can impact gross margin relative to the baseline case by nearly 10% in the most restrictive scenario. The degree to which these constraints impact gross margin largely depends on how generation cost relates to on-peak and off-peak market prices. If the generation cost is lower than on-peak pricing and higher than off-peak pricing, these operating constraints will impact value depending on the magnitude of the price differences.

There may be a point beyond which additional flexibility adds little value, as illustrated here by maximum starts. Under the assumed market conditions, maximum gross margin is reached at 21 starts, the number of weekdays in the month.

For the market conditions in this analysis, changes to ramp rate and LOL have relatively small impact on the baseline gross margin. Together they



10. Relative impact of operating constraints are clearly shown in this summary presentation for the base case: 500-MW HOL, 175-MW LOL, 7000-Btu/kWh heat rate, minimum uptime and downtime of eight hours; unlimited number of starts; one-hour startup profile; 3-MW/min ramp rate

have less than a 1% impact on the gross margin at the most constrained points. However, the LOL becomes a much more prominent constraint when operating flexibility is compromised. To illustrate: If a unit were unable to shut down at night when its generation cost is above the market price, the unit may be forced to run at its LOL. Having the lowest LOL to minimize fuel burn during this time will have a significant impact on gross margin.

In summary, any constraint that impedes flexibility and efficiency has a negative impact on gross margin. Being able to model the constraints and account for the variation allows asset owners to put capital into areas that offer the highest return and allows asset buyers the ability to distinguish seemingly similar generation assets. Similar analysis can be done for contractual constraints that affect transmission flow, emissions output, fuel usage, and startup limitations. Relating to number of starts, the next article in this series will investigate combined-cycle units that are under a long-term service agreement (LTSA) that may limit the number of starts of the gas turbines. As shown in this analysis, limiting starts can significantly affect operating gross margin. CCJ

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PCI is a leading provider of generation supply management and optimization software. The company has grown steadily since startup in 1992 and is recognized for delivering solutions that are critical for operations and for asset, financial, and risk management. Nearly half of all the power generation in the US is optimized with PCI software. The analysis presented in this article was conducted using PCI's GenTrader®.