Combined Cycles – Is It Time To Build?

by

Myron Rollins
Jacob Tutmaher
Ted Pintcke
Black & Veatch

ABSTRACT
The combined cycle power plant market has exhibited many of the same characteristics as other commodity markets, including supply and demand pressures that cause large fluctuations in price. The old commodity market adage of buy low and sell high also applies to the combined cycle market. This paper presents a review of the last market cycle for combined cycle power plants from the 1990s through the early 2000s. It evaluates the lack of demand for combined cycle power plants in the early 1990s; the accompanying reduction in prices followed by the large increase in demand for combined cycles in the late 1990s and extending into the early 2000s; and the accompanying increases in price and eventual oversupply. The implications of this cycle were certainly reflected by the rise and fall of Enron as well as other independent power producers. The winners in the cycle were those that entered the combined cycle market early when prices were low and refrained from participating when prices became high. The losers were those that were slow to move into the market and, as a result, were saddled with high capital costs. Other factors contributing to the combined cycle market during this period, including natural gas prices, cost of money, performance, cost of generation and need for capacity are also evaluated in this paper.

The current combined cycle market has many similar attributes to the previous market cycle, and this paper presents those attributes and attempts to answer the question of whether now is the time to build combined cycle power plants based on lessons learned from the last market cycle.

INTRODUCTION
The concept for this paper was inspired by the observation that the combined cycle market seemed to be exhibiting many of the attributes of the previous market cycle. First, some of the terminology and behaviors that were associated with the last market cycle need to be explained. In the mid-1990s, there was little activity in the combined cycle market. General Electric introduced the 7FA combustion turbine in 1994, and as it and the other F-class combustion turbines were accepted as reliable, the combined cycle market began to take off. When the market was starting, one of the terms and practices used was “market pricing.” Market pricing was the practice of reducing the cost of engineering, procurement and construction (EPC) bids even before demonstrating the ability to construct the project at the previous higher bid. Market pricing was the result of fierce competition from hungry EPC contractors. The only way that market pricing could be successful for the EPC contractor was with “buy down.” Buy down is the practice of negotiating for the purchase of equipment and services below the price estimates in the EPC bids. At the beginning of the previous boom, assumed buy down on major equipment was common practice, but the term had ceased to be used until recently. The primary reason for recently discounting buy downs was the rampant rate of escalation of balance-of-plant commodities and equipment often not accounted for in the EPC contract price as bid.
When combined cycle market demand exceeded supply, the situation changed drastically. Market pricing disappeared, and EPC contractors that had uncontracted capability began charging premiums as well as reservation fees for project teams. Equipment suppliers exhibited the same behavior. “Queues” formed for major equipment (combustion turbines, heat recovery steam generators [HRSGs], and steam turbines). Speculators even entered the market purchasing manufacturing slots, further tightening the market and increasing prices. For example, F-class combustion turbines that were selling for $25 million at the beginning of the boom, soon sold for $40 million.

Supply and demand behaviors affected every aspect of the combined cycle market in the last boom. For instance, at the beginning of the boom 2x1 F-class combined cycles in the survey had EPC prices as low as $160 million for projects entering service in 2000. This compares to a 1x1 F-class brownfield combined cycle plant entering service last year with an EPC price of approximately $345 million, resulting in nearly a factor of four increase in 11 years without accounting for economies of scale, greenfield versus brownfield and inflation.

The paper addresses the data in detail to the extent possible for not only capital cost but also natural gas prices and the cost of money to provide some insight into what the market might bring in the future.

DEMAND

Many factors affected the demand for combined cycles including the onset of deregulated markets, international markets and the bankruptcy of Enron. This paper does not focus on those factors but rather examines the number of plants announced and the number of plants entering commercial operation. Black & Veatch examined the demand for EPC services for coal units as well because the coal boom had a large influence on the cost of combined cycles in more recent years. The main source of data used for this paper was the Ventyx Velocity Suite: EV Power database.

Figure 1 presents the announced and installed plant capacity annually for combined cycles 200 megawatts (MW) and larger.

The last boom in combined cycle construction is shown on Figure 1. At first glance, the amount of combined cycle capacity announced that was never constructed seems rather startling, but in that era, there were a lot of weak developers, many of whom ultimately failed. On average, the announced year preceded the year of commercial operation by 3.7 years for the combined cycles that achieved commercial operation. While not yet as pronounced as the previous boom, it appears that the trend in announced combined cycles is once again on the increase. In addition, it should be noted that the year 2012 numbers are only through August.
Figure 1
Announced and Installed Combined Cycle Capacity by Year

Figure 2
Announced and Installed Coal Capacity by Year

Figure 2 shows announced and installed coal units. When Black & Veatch began looking at combined cycle costs, it became obvious that something other than the amount of combined cycle capacity being constructed was driving the cost of combined cycles. Black & Veatch attributes this primarily to the coal boom, shown on Figure 2. The difference between announced and
installed coal capacity is even more pronounced than for announced and installed combined cycle capacity. The announced coal capacity had environmental opposition to contend with as well as high capital costs. On average, the announced year preceded the year of commercial operation by 6.6 years for coal units that achieved commercial operation.

Figure 3 presents the weighted average capital costs of the combined cycle capacity installed on a dollars per kilowatt ($/kW) basis. The capital costs have been adjusted to 2011 dollars by the Gross Domestic Product (GDP) deflator. The capital costs include costs for combined cycles constructed at greenfield sites, as well as combined cycle additions at existing sites. The capital costs include owner’s costs, as well as EPC costs, but do not include Allowance for Funds Used During Construction (AFUDC) or interest during construction. Black & Veatch expended significant effort in an attempt to scrub the cost data. Black & Veatch has been involved in many of the combined cycle projects that were constructed, either as the EPC contractor, owner’s engineer or independent engineer. Even with this involvement in many of the combined cycle projects, the capital costs including owner’s costs were difficult to ascertain because many of the combined cycles were constructed by developers who were not under the same reporting requirements as utilities. The Ventyx Velocity Suite uses the best sources available for determining project capital cost; however, many of the capital cost numbers required adjusting. The most common issue encountered was that the total cost for multiple units was entered as the cost for each unit or vice versa. The combined cycle capital costs are presented for the year that the combined cycle entered commercial operation. The costs exclude two projects on Long Island that utilize dry cooling towers. These projects were expensive on a $/kW basis because of their Long Island location and the reduced output due to the dry cooling towers. The combined cycle costs for 2012 are for units that entered commercial operation by August 2012 and are in nominal dollars.

Figure 3
Combined Cycle Capital Costs

Figure 4 indicates what is driving the combined cycle capital costs shown on Figure 3. While the demand for combined cycles in the United States is a significant driver in determining their cost as demonstrated on Figure 1, other factors are influencing their cost. One of those was the boom in coal units. While the amount of new coal capacity was not nearly as significant as the amount of new combined cycle capacity, a megawatt of new coal capacity has more influence on the demand for EPC services than a megawatt of combined cycle capacity. To capture the greater impact of the coal capacity on the demand for EPC services, Figure 4 shows an estimate of the construction man-hours for combined cycle and coal capacity as a proxy for the demand for EPC services.
Costs are reported in the EV Power database for the year of commercial operation. EPC prices, however, are negotiated prior to the start of construction. As such, they are more influenced by the level of announced projects than the amount of capacity entering commercial operation. In other words, EPC pricing should reflect the perceived market at the time the EPC contracts are being negotiated. Figure 4 therefore presents estimated construction man-hours based on the announced capacity rather than the capacity entering commercial operation. Finally, the combined cycle costs on Figure 3 were shifted three years on Figure 4 to better align with the announced capacity and the timing of the negotiation of EPC contracts.

There are a number of factors that have not been considered herein and that will also affect EPC pricing. Among them is the nuclear boom that resulted in several Combined Operating License Applications being submitted from 2007 through 2009 and may have influenced the significant increase in combined cycle costs during that time frame. Other factors include the international market and the large amount of air quality control equipment installed at existing coal units because of air quality regulations.

Several observations were drawn from Figure 4. When the combined cycle market went from a period of very little activity to significant activity, prices jumped considerably. The jump from 1996 to 1997 shown on Figure 4 was $189 per kW, or 53 percent. This tracks well with the increase in F-class combustion turbine prices from approximately $25 million to $40 million, or a 60 percent increase. It appears that combined cycle prices have begun to decrease as the coal boom has worked its way through the EPC market. It also appears that the amount of combined cycle capacity announced is again beginning to increase. It should be noted that the 2012 capacity shown on Figure 4 is only through August. It will be interesting to see if the lack of coal and nuclear EPC projects will be sufficient to significantly lower the price of combined cycles or whether increases in the amount of new combined cycle capacity will keep prices up.
NATURAL GAS
There are other factors besides the capital costs of combined cycles that contribute to their market. The second major factor is the cost of natural gas. Figure 5 presents the daily Henry Hub spot price in nominal dollars and illustrates the volatility of natural gas prices. Figure 6 presents the annual average Henry Hub spot price in 2011 dollars. Data for 2012 are presented in nominal dollars and are the average through August. Natural gas prices for 2012 are the lowest in the period evaluated and have dropped below those that preceded the combined cycle boom.

COST OF MONEY
The third major factor in the cost of power from combined cycles (or any power plant) is the cost of money. Figure 7 shows the historical average annual rate for Corporate AAA rated bonds. The 2012 rate is the average through August. The cost of money is currently the lowest over the entire period and is two-thirds of the rate from 2003, the peak year for new combined cycles entering service from the last combined cycle boom.

Figure 5
Daily Henry Hub Prices
Figure 6
Annual Henry Hub Prices

Figure 7
Corporate AAA Historical Average Bond Rates
PERFORMANCE

The performance of combined cycles has been improving. The heat rate of General Electric’s 7FA 2x1 combined cycle as reported in Gas Turbine World magazine has decreased to 5,831 Btu/kWh lower heating value (LHV) in 2012 from 6,110 Btu/kWh LHV in 1996, or a 4.6 percent improvement since the beginning of the last combined cycle boom. In addition, newer more efficient and larger combustion turbines have been introduced, further improving combined cycle efficiency. As reported by Gas Turbine World, Mitsubishi’s 2x1 J-class combined cycle has a 5,531 Btu/kWh LHV heat rate, which is an improvement of 9.5 percent from General Electric’s 1996 2x1 7FA. At a 60 percent capacity factor and the 2012 cost of money and natural gas prices, that 9.5 percent heat rate improvement is equivalent to approximately $122 per kW in capital cost savings, which brings today’s capital cost shown on Figure 3 that much closer to the combined cycle capital costs before the last boom.

COST OF GENERATION

Figure 8 presents a comparison of the cost of generation from combined cycles power plants in 1997 at the beginning of the combined cycle boom compared to the present. The comparison includes capital and fuel costs, but does not include operation and maintenance (O&M) costs. The capital costs are based on the costs from Figure 3, with the 2000 in-service capital costs used to represent the 1997 market capital costs. The cost of capital is based on the corporate bonds from Figure 7 with 200 basis points added to reflect an estimate of the weighted average cost of capital. A 30-year capital recovery factor and a 60 percent capacity factor were used to calculate the capital portion of the costs shown on Figure 8.
Fuel costs were based on the natural gas prices shown on Figure 6 and the 6,110 Btu/kWh heat rate for the 2x1 7FA turbine in 1996 and the current heat rate for the 2x1 J-class turbine at 5,531 Btu/kWh, both adjusted to higher heating value (HHV). Figure 8 shows that today’s cost of generation considering capital and fuel costs from combined cycles is approximate 79 percent of what it was in 1997 adjusted to 2011 dollars.

**NEED FOR CAPACITY**

During the last combined cycle boom, there was a lot of activity in the electric marketplace. Much of the United States was deregulating the utility industry and creating new opportunities for independent power producers to enter the market. A large amount of combined cycle capacity was built at that time in response to these opportunities. The market became oversupplied as a result, and many developers went out of business, including Enron, which declared bankruptcy in December 2001. Figure 9 presents the annual capacity margins from the Energy Information Administration; it shows capacity margins decreasing from 1995 through 1998, when developers entered the market with capacity margins reaching a low of 14.3 percent. Capacity margins increased from 2001 through 2004 as these combined cycles entered commercial operation, reaching a high of 20.9 percent in 2004. Currently, as a result of the economic downturn in 2008, capacity margins have risen to their 2011 high of 22.2 percent. These high-capacity margins mitigate the market for new combined cycles.

![United States Historical Capacity Margin](image)

**Figure 9**
United States Historical Capacity Margin

In addition to the economic recovery, one factor that is projected to increase the market going forward is the retirement of existing coal-fired generation because of increasing regulatory requirements. As a result of these regulations, Black & Veatch’s 2012 Energy Market Perspective Mid-Year Report projects 61,500 MW of coal capacity will retire by 2020. This amounts to approximately 7 percent of the 2011 capacity margin and will serve to increase the need for capacity from combined cycles. The projected coal retirements equal the entire amount of combined cycle capacity installed in 2002 and 2003, the peak years of combined cycle installations in the last combined cycle boom.
CONCLUSIONS

Many factors make this a good time to buy combined cycles, including low natural gas prices, falling capital costs, low cost of money, and increased combustion turbine performance and efficiency. All of these factors could potentially create an opportunistic market for combined cycle development going forward. Furthermore, while increased reserve margins may mitigate new combined cycle development currently, pending environmental regulations may decrease these reserve margins in the future, further increasing opportunities for combined cycle development. It is important to note that while pressure on the EPC market from the past coal and combined cycle booms has waned in recent years, making possible the decrease in capital cost, increased demand for combined cycles could again increase these capital costs, as demonstrated by the last market cycle.