UKERC Technology and Policy Assessment

Cost Methodologies Project: CCGT Case Study

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This working paper was produced as part of the TPA Cost Methodologies project.

Contents

1 Introduction

This case study examines Combined Cycle Gas Turbine (CCGT) cost forecasts as well as coeval cost estimates and their underlying methodologies. It was prepared as part of a series of case studies designed to inform the UKERC TPA report 'Presenting the Future: An assessment of future cost estimation methodologies in the electricity generation sector.'

The study is the result of an extensive review of scientific journal articles as well as industry and government reports; it also draws on key insights from innovation theory. The presentation structure is aligned to the three aims of the study, namely:

- To examine trends in contemporaneous cost estimates and in cost forecasts (Section 2);
- To understand the driving factors of those trends and the reasons for disparity between anticipated and actual costs (Section 3);
- To draw lessons and identify implications for cost estimation methodologies (Section 4).

2 Cost trajectories

This section evaluates the disparity between expectations implicit in cost forecasts and actual cost developments in the market. It must be pointed out that within the literature reviewed contemporaneous 'actual' cost estimates are more abundant than forecasts for a variety of reasons that, rather than being elaborated here, are best exemplified in Section 3 and briefly discussed in Section 4.

An important feature of data reported in the literature is that, despite the variability and dominance of fuel costs in the levelised cost of electricity (LCOE), forecasts and contemporaneous cost estimates are not reported in comparable capital expenditure terms but as levelised costs. This complicates the analysis of technical performance improvements in their own merit. Therefore, it seems pertinent to suggest that all levelised cost trajectories should be interpreted in the context of fuel price developments.

2.1 Expectations of future CCGT-derived electricity costs: forecasts

Power generation from CCGT has historically undergone several changes of plant configuration paradigm and several phases of 'broader system' or context changes (Islas, 1999). These phases have been defined by markedly different political and macroeconomic factors to which the endogenous technical development trajectory has been responding. From its early stages, socio-political drivers, such as military efforts, as well as the worldwide oligopolistic dominance by four providers, have imbued this trajectory with confidential sensitivity about cost data. The forecasting of levelised costs has mainly been the domain of energy research institutes, government analysts and some of their consultants. Engineering firms involved in construction tend to be cautious in forecasting and have typically provided non-attributable contemporaneous 'actual' cost estimates instead.

Compounding the confidentiality problem, the fact that fuel cost is the dominant component of LCOE, approximately 75%[1], has rendered forecasting complex and fraught with pitfalls. It is the influence of fuel cost, however, that has shaped the two main trends in forecasts. Combined analysis of worldwide forecast data points and the

[1] This proportion was typical during the early 2000s (IEA, 2007) and can clearly vary significantly with fuel cost.

trajectory of gas prices over the past 15 years identified the end of 2005 as the transition point from relatively constant cost forecasts to much less optimistic ones. Figure 2.1 shows the two trends, after converting and inflating costs to £$_{2011}$, as well as the markedly higher variability in post-2005 forecasts due to the widespread inclusion of (methodologically and geographically varied) gas price volatility calculations.

As illustrated in Figure 2.1, pre-2005 forecasts proposed stable costs within the range of 25 to 41 £$_{2011}$/MWh up to 2050 suggesting that technical advances, leading to efficiency gains, and exogenous upward cost pressures would cancel each other out. The logic behind the expectations of cost development in this period can perhaps be best expressed as the disregard of the external forces that became more forcibly obvious in the subsequent period.

Post-2005 forecasts include significantly higher projections of up to 115 £$_{2011}$/MWh already by 2020 reflecting a more complex set of influencing factors and more varied assumptions associated with each factor. After fuel prices changed the tone of international forecasts, they were followed by additional pressures that explain the large difference between pre-2005 and post-2005 forecasts. For instance, since 2006 the importance of greenhouse gas emission abatement in European policy has reinforced the upward trend and introduced further uncertainty through the attempt to set a price on carbon and through the trading or fiscal mechanisms that might be used to act on it (Parsons Brinckerhoff, 2010).

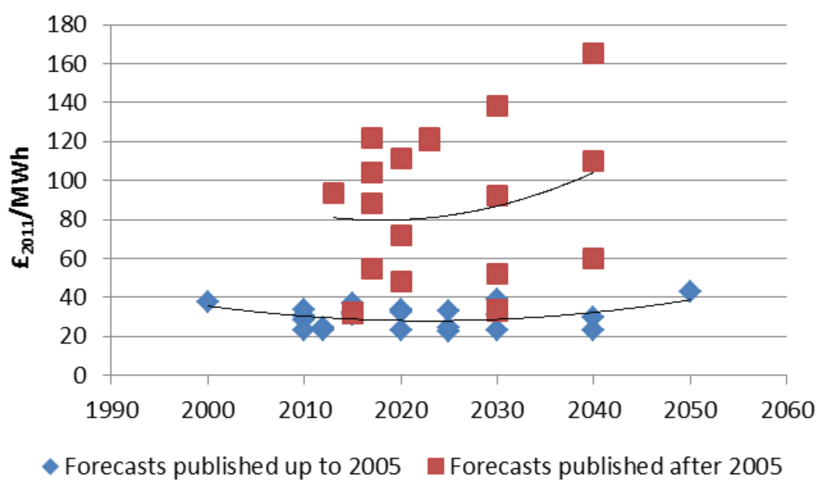

Figure 2.1 International forecasts of LCEE for CCGT until and after 2005

Another part of the rationale of post-2005 forecasts is the evolving context underpinning projections for 2050, which actually refers to plants that would be built from the mid-2020s onwards. Important new considerations such as changes in generation mix and policy include (Timera Energy, 2011):

- Support of increasing volumes of 'must run' renewable capacity, e.g. feed in tariffs, will tend to reduce average CCGT load factors and increasingly shift the risks associated with balancing intermittency onto thermal plant.

- In contrast with base-load clean spark spreads (CSS)[2] traditionally used as calculation basis for required returns, future CCGT plant are likely to operate at much lower load factors increasingly servicing peak-load periods.

- With lower load factors, future margins for a new CCGT plant are likely to be increasingly focused into periods of peak system net demand (i.e. system load less intermittent output).[3]

- Future CCGT plant will compete in capturing attractive margins with low-cost projects of life extension, e.g. refurbishment, of existing lower-efficiency, steam-only thermal plant.

2.2 Actual cost development: contemporaneous cost out-turn estimates

It is worth emphasising that cost figures are mostly reported by third parties such as government agencies, research institutions or consultancy firms rather than actual commercial data disclosed by operators or engineer, procure and construct (EPC) contractors. Because it is often unclear how commercial terms, technical assumptions and ancillary or administrative costs were incorporated, the reported 'actual' costs can be broadly considered for the purposes of this study as estimates.

The literature identifies three sub-phases of technological development and learning up until the period of consistently increasing costs starting in the mid-2000s.

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[2] The spark spread is the difference between fuel price and electricity price and it is referred to as clean spark spread when it relates to gas and dark spark spread when it relates to coal (Bredin and Muckley, 2011).

[3] It is peak and super-peak margins rather than the base-load CSS that are likely to support future investment in CCGT as capacity margins tighten (Timera Energy, 2011).

- For the period 1981-1991, Cleason Colpier and Cornland (2002) identified a 'negative' experience curve (due to progress ratios higher than 100%); this is considered to be a characteristic of developmental stages for CCGT preceding other phases of more intense competition (Cleason Colpier and Cornland, 2002, Junginger et al., 2008).

- For the period 1991-1997, learning associated with a learning rate of 25% is attributed to a shakeout phase (Cleason Colpier and Cornland, 2002). An unintended consequence of this phase was that the surge in demand induced fierce competition, which accelerated developments and deliveries to the point that new models were marketed while previous ones were "still under test 'in the field.'" This was then compounded by technical complications in the late 1980s and early 1990s that temporarily damaged the image of CCGT (Islas, 1999, Watson, 1997).

- After 1997, a maturity phase started, which was characterised by a learning rate of approximately 10% (Cleason Colpier and Cornland, 2002).

Data for worldwide contemporaneous out-turn estimates from the late 1980s until the early 2010s are presented in Figure 2.2. The change of trend that started in the mid-2000s, contrary to forecasts for the early 2010s, becomes evident despite the presence of outliers.

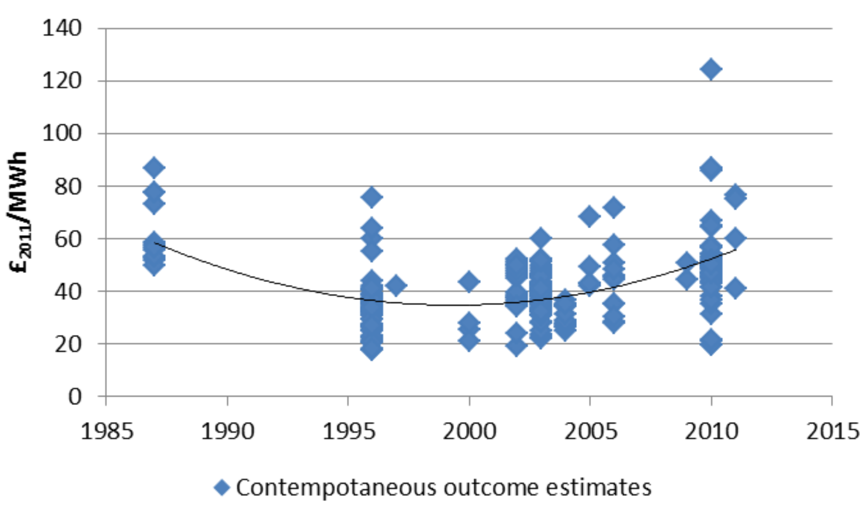

Figure 2.2 Contemporaneous estimates of LCOE for CCGT

A comparison between Figures 2.1 and 2.2 confirms that forecasts for the year 2000 were actually too conservative and underestimated the potential for cost reduction. Although this was in large part possible due to positive exogenous conditions. Also, pre-2005 forecasts seemed to be almost right in notionally predicting cost reduction until the mid- to late 2000s followed by gradual cost increases. Although they seemingly captured the essence of both the approaching thermodynamic limits to efficiency gains and the external factors undermining learning, they appear to have underestimated the latter. Clearly, the factors that drove cost increases in the mid-2000s have permeated the post-2005 forecasts with the resulting variability shown but within a distinct upward trend.

To provide a depiction of out-turns compared to expectations within forecasts, the available data points were simplified into yearly average figures. These contemporaneous and forecast estimates were consolidated along a time horizon covering mainly from 1990 until 2020. Figure 2.3 shows how forecasts for 2010 reflected expectations of cost reductions of nearly 25% relative to the expectations for the year 2000. In reality, the opposite happened and actual costs for 2010 increased by 25% relative to expectations for the year 2000.

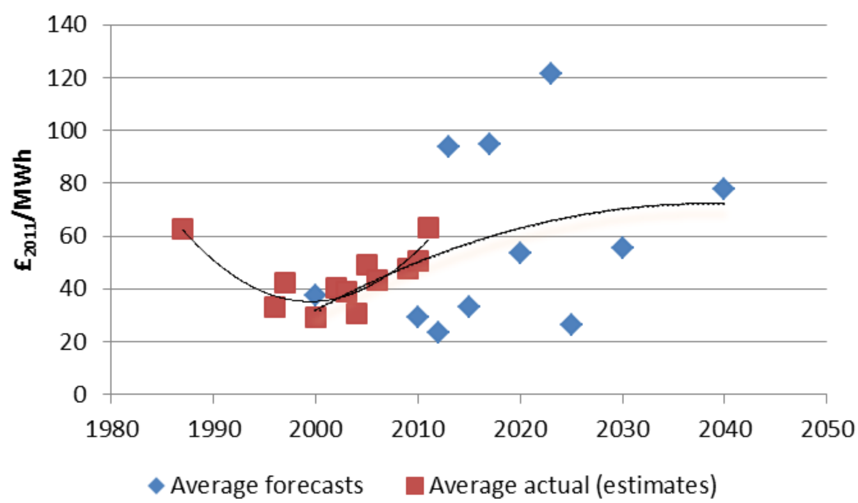

Figure 2.3 Comparison of averaged forecast and actual LCOE figures for CCGT

Data on out-turns show how learning effects have been overshadowed by exogenous factors since the inflection point in the mid-2000s. It can be observed from the data for forecasts for the late 2010s that contextual changes have informed forecasters and led to some significantly higher projections.

2.3 Cost estimate variability

Among the reasons for disparity between expectations and actual cost developments four factors have been identified. They can represent exogenous or endogenous influences or an endogenous or methodological response closely linked to an exogenous force.

i) Confidentiality and the kind of data available

ii) Influence of fuel costs

iii) Fuel-dependent deployment and deployment-dependent learning (across sectors)

iv) Policy responding to macroeconomic and geo-political forces

Confidentiality and the kind of data available

An endogenous feature of the gas-fired power generation sector is scarcity of data on actual generation costs. The methodological consequence recognised in the literature is that significant numbers of forecasts are derived through experience curves based on price data rather than cost (Junginger et al., 2008). Such curves have become generally accepted by analysts due to lack of actual plant operator data (Neij, 2008). This acceptance has substantial implications. The Boston Consulting Group (1972) pointed out that differences may occur between cost and price development in various intervals and that sustained price reduction can reflect a true cost reduction for already established products as illustrated in Figure 2.4. They add that companies that survive into maturity eventually pass on cost reductions by keeping their margins constant, as opposed to letting them grow unsustainably, which serves as deterrent for new competitors in what would otherwise appear as a highly lucrative market segment. Therefore, the significance of using price data is that due to differences in cost and price developments, experience curves used to study short or specific time periods particularly in early developmental stages, result in inaccurately reported learning rates (Neij, 2008).

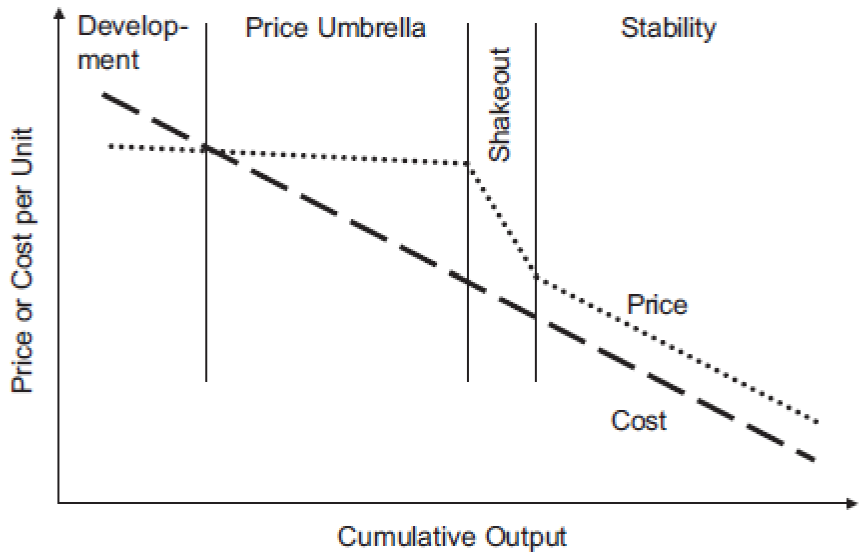

Figure 2.4 Price-cost relationship along product development stages. Source: Boston Consulting Group (1972)

The next sub-section helps to shed light on one of the reasons why the shake-out of the late 1990s, coupled with increases in efficiency, was not followed by sustained cost reductions.

Influence of fuel costs

Unlike levelised costs for other generation technologies studied in this series and in the main report, levelised costs for CGGT power generation are significantly influenced by fuel costs. Figure 2.5 shows that, as reported by Parsons Brinckerhoff (2004) in the early 2000s fuel cost already accounted for nearly 60% of generation costs. Furthermore, the IEA (2005) highlighted that changes in other variables for CCGT, such as availability factor addressed in the next section, are not so important because the share of fuel in total generation cost is predominant, around 75% or higher, and levelised costs depend mainly on projected gas prices during plant lifetimes.

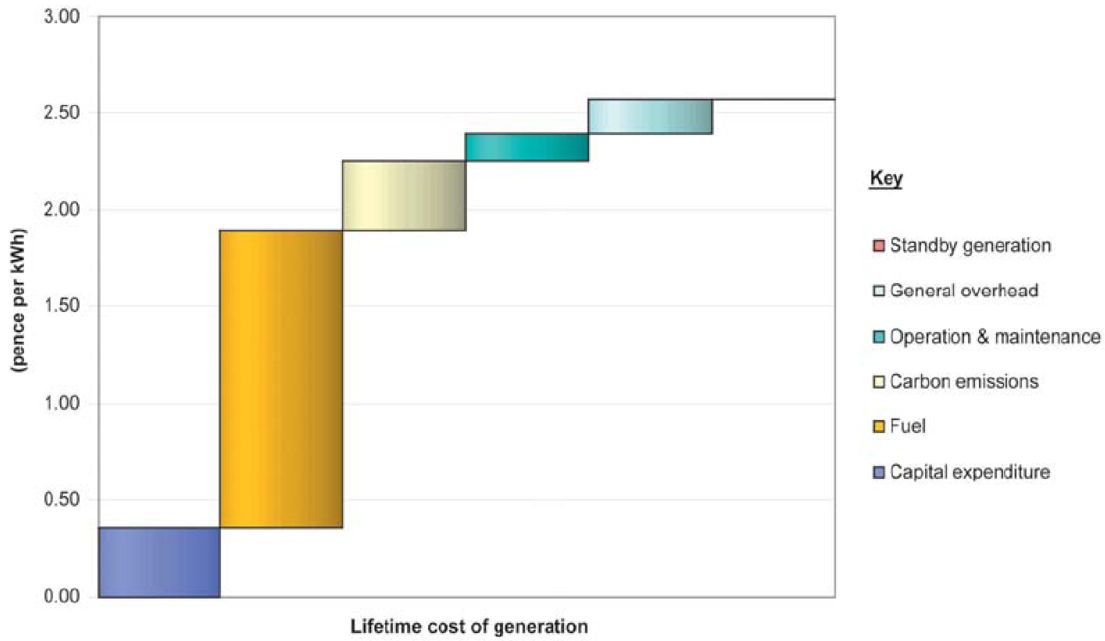

Figure 2.5 LCOE breakdown for CCGT in the mid-2000s

To analyse and exemplify the breakdown of the LCOE for CCGT in a sample forecast, percentages have been derived from data published by Parsons Brinckerhoff (2004) and presented in Table 2.1. It is worth noting that this projection predates the 2005 and 2008 fuel price rises that changed the tone of later forecasts. In fact, it suggested small reductions in the cost items that will likely drive future cost increments: fuel and carbon emissions.

	Mid-2000s		2015	
	p/kWh	%	p/kWh	%
Capital expenditure	0.36	13.95	0.36	14.40
Fuel	1.53	59.30	1.47	58.80
Carbon emissions	0.37	14.34	0.35	14.00
Operation & maintenance	0.14	5.43	0.14	5.60
General overhead	0.18	6.98	0.18	7.20
Standby generation	0.00	0.00	0.00	0.00
Total	2.58	100.00	2.50	100.00

Table 2.1 Cost breakdown estimates for mid-2000s and forecast for 2015. Source: Derived from Parsons Brinckerhoff (2004)

In reality, gas prices at Henry Hub, for the US market, and at the National Balancing Point (NBP), for the UK market, have been increasing since the turn of the century with particularly pronounced spike-rises at the end of 2005 and the beginning of 2008 to levels up to 600% the typical values of the 1990s (Alterman, 2012). It is worth noting that since 2005 the lowest international level seen at the end of 2009, which reached 3.1 USD/mmBtu at Henry Hub, was still approximately 41% higher than the prices in late 2001 of 2.2 USD/mmBtu.[4]

Fuel-dependent deployment and deployment-dependent learning

As will be outlined in the chronological analysis of drivers in Section 3, deployment of CCGT has been subject to several pre-conditions throughout the decades. This was epitomised by the regulatory restrictions on the use of natural gas for power generation on both sides of the Atlantic[5] as a result of the oil crisis in 1973 (Winskel, 2002). These

[4] See Alterman (2012) for a concise analysis of international gas prices from Henry Hub for the USA, the NBP for the UK and the Bundesamt für Wirtshaft und Ausfuhrkontrolle (BAFA) for Germany.

[5] See also Section 3.2 for details on the European Directive 75/404/EEC on the restriction of the use of natural gas in power stations and on the Fuel Use Act of 1978 of the USA.

restrictions came only a couple of years after efficiency levels of CCGT had surpassed those of the then dominant steam-only plants as can be observed from Figure 2.6. The effect of the restrictions was that CCGT plant construction virtually ground to a halt and, for instance, only one utility CCGT plant was built in the USA between 1979 and 1986 (Smock, 1989).

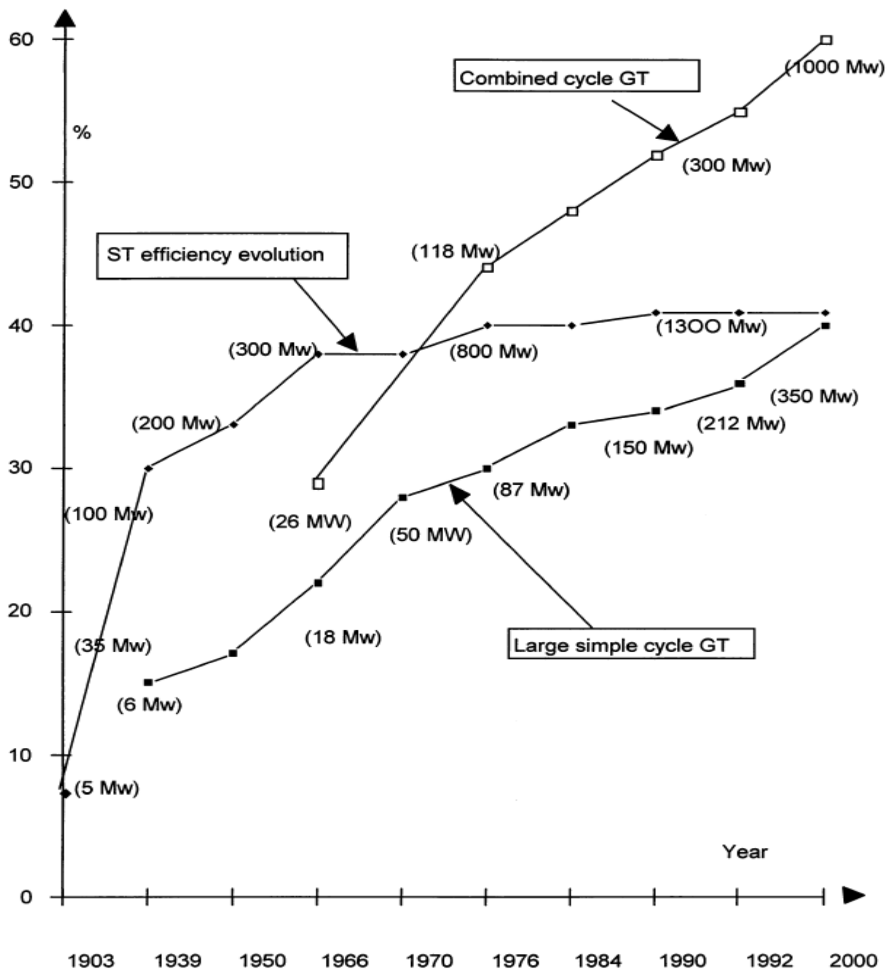

Figure 2.6 Efficiency development of CCGT compared to simple steam and gas turbines

It was largely due to technological flexibility in the application of the gas turbine, as highlighted by Watson (1997), that the technology has been able to survive periods of low demand in order to be deployed again later in CCGT plant. For instance, orders from the Middle East for oil extraction equipment in the late 1970s kept demand for the main turbine above zero. At the same time, significant development and investment in jet engines took place, which has always been a key advantage for General Electric (GE) in having capabilities in both jet engines and industrial gas turbines (Watson, 1997).

As progress ratios, learning rates and cost reductions are derived from deployment levels, the examples and narrative in this study[6] illustrate how, in the history of CCGT, learning has been partly overwhelmed by exogenous factors[7] despite technical improvements. This array of external forces has rendered single-technique cost forecasting more complex and prone to blind spots vis à vis real market events. The result is a challenge for future forecasters to update their techniques to reflect the likely additional influences identified.

Policies and responses to macroeconomic and geo-political forces

Apart from technical development, energy and industrial policy as well as general market formation elements have tended to strongly influence learning and cost reductions. Different courses taken by international policies have made cost reductions increasingly difficult to forecast. Although details of policy implications are subsumed under the overall presentation of drivers, a thread of influences can be identified and briefly summarised here.

From its early stages, development of gas turbines was the subject of intense state support of military applications; in the USA alone, military spending to improve the turbojet amounted to USD450 million per year between 1976 and 1986 (Williams and Larson, 1988).

A non-policy, international market factor in the trajectory of the gas turbine was cross-sectoral applicability. Gas turbine use in military and civil aeronautics, surface transport (cars, trucks, military and civilian boats), chemical industry, blast furnaces and transportation of oil and gas was a vital feature of the continued development of the core technology. This technical versatility helped to realise the potential for renewed and accelerated technological development in the post-war years (Islas, 1999). As outlined previously, this also helped technology advancement to survive even though some business units of the main providers did not (Watson, 1997).

Lifting the restrictions on the use of natural gas for power generation (by 1987 in the USA and by 1991 in the EU) was a very positive reinforcement of general political trends originating in the 1970s and 1980s (Watson, 1997). Three societal concerns that have shaped energy policy, and the resulting market trends, since the late 1970s are presented in Table 2.2.

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[6] See previous sub-section as well as Section 3.3

[7] E.g. fuel price, fuel use restrictions and environmental regulations.

International societal concern	Market and policy reactions
Concern for security of energy supply	• Fossil fuel price shocks • Restrictions on fuel use particularly affecting oil but also natural gas
Concern for local safety and international security	• Stringent regulations particularly relating to nuclear power waste disposal, reactor safety and proliferation risks all with high compliance costs
Concern for avoiding environmental damage	• Limitation of all noxious emissions from fossil fuels, particularly affecting carbon emissions of coal-fired generation • Market and fiscal instruments to set a price on greenhouse gas emissions

Table 2.2 Policy and market reactions that have influenced deployment, learning and cost trajectories. Source: Derived from Islas (1999)

As Watson (1997) emphatically pointed out, it is worth noting that until the mid-1990s technology development through crucial, even survival, stages received significant support from governments and corporations.[8] Subsequent to the highly consequential market adjustments mentioned above, all moderately in favour of CCGT, came the liberalisation of the electricity generation market. This liberalisation of national electric markets since the 1990s and 2000s enhanced the operating flexibility of CCGT plant. In particular, arbitrage opportunities between gas and electricity markets have a value which is not captured by traditional valuation methods and contributed to the preference for CCGT plant by new market entrants (Roques, 2007).

[8] Section 3.4 provides additional details on defence spending as well as state funding for fuel efficiency in the USA and Japan.

Looking into the future, cost forecasting for CCGT generation entails both some clarification and, predictably, new challenges. Important examples are:

The technology is mature and efficiency gains are close to thermodynamic limits; the only future possibilities of noteworthy design changes are linked to the transfer of the combined-cycle to the upcoming deployment of integrated (coal) gasification combined cycle (IGCC) (Timera Energy, 2011).

The risks and performance penalties associated with organisational forgetting or knowledge depreciation (similar to those associated with nuclear power plants)[9] will continue to be prevented, as in the past, through versatility across the aviation, industrial and power generation industries. According to the analysis for this study, this is likely to apply even as CCGT is pushed further into peak-load merit and construction becomes less frequent over the next 15 years.[10]

The trajectory of fuel costs can only be expected to increase over the lifetime of plant built over the next two decades, even though LNG supply markets will be more diverse than previous routes. The main uncertainty source is likely to remain the price of carbon exemplified by the sensitivities used by (Wissel et al., 2008).

In the near-term, methodological variation is likely to continue. For a significant number of the estimates published it is not clear whether engineering assessments or learning curves are used.

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[9] Reference is made to the way technical learning can be eroded or undermined when firms in the industry stop building plant for substantial periods of time. This can lead to lack of reproducibility, obsolescence, need for re-training and higher set-up and transaction costs. See also the case study on nuclear power generation in this series.

[10] Not least because of developments in related turbine applications mentioned in previous sections. Indeed, this feature ensured that the technology was not discontinued during times of questionable success as a power generation technology (Watson,1997).

3 Actual cost trend drivers by development stage

Section 3 presents the analysis of the most significant drivers that have influenced cost trends for CCGT plant. In accordance with the terms in the main report, this case study distinguishes whether drivers are endogenous, exogenous to the technology or a result of methodological choices (see main report for further explanation). Macroeconomic drivers, as well as other non-technical pressures at national or international level have been subsumed under the exogenous category. All drivers are presented chronologically owing to the coincidence of highly influential events with the end of each of the last five decades; for instance, the oil crisis in 1973, the US Fuel Use Act of 1978 and its repealing in 1987.

3.1 The gestational period pre-1950s and 1960s – Early technology transfer

Early developments under fuel cost disadvantage

This subsection presents drivers that made early contributions to technical learning and eventually to cost reduction. The technology transfer element implies a prompt endogenous reaction to exogenous forces.

In the 1940s technology transfer began to drive technological development as turbines started evolving along two pathways. The first was characterised by small, light and technically advanced aero-engines; the second was characterised by larger, more robust engines for industrial power generation (Haigh, 1991). In the 1950s, the first wave of substantial technology transfer took place when small gas turbines based on aero-engine turbojets were deployed by numerous utilities worldwide. Their significantly shorter building times and faster ramp-up times from start-up to full load seemed to off-set their fuel costs, which were higher than for coal or oil-fired steam turbines. Without this attributes, there would have been no interest even in early niche applications. At that point, gas turbines were either used for peak load or kept as reserve (Riley et al., 1990).

At an industry-wide level, the following developments assisted the initial development trend in learning and efficiency improvements:

- The trend towards consolidation within the British electricity supply industry accelerated during World War II and resulted in post-war nationalisation; meanwhile the research efforts of plant manufacturers and utilities were concentrated on improving steam turbine technology (Winskel, 2002).

- The first CCGTs were developed in the 1950s but natural gas was perceived to be rare. It was widely accepted that to compete with steam turbines either cheaper fuels or more sophisticated layouts were necessary, neither of which materialised in the subsequent 15 years (Winskel, 2002).

- As Horlock (1992) argued, it is not widely known that in the early 1960s small CCGT plants, often in combined heat and power (CHP) mode, were also installed in Europe and North America. Total thermal efficiencies of over 40% were possible, already exceeding those of coeval steam turbine plant (Horlock, 1992).

The factor that undoubtedly drove efficiency increases from the mid-1960s onwards was the increase in the maximum inlet temperature of the gas turbine, as reported by Horlock (2002). He explained that this led to higher specific work[11] and enabled the recuperative combined plant to become increasingly competitive with conventional steam plant.

Cross-sectoral influence and macroeconomic impetus

This subsection begins by presenting positive drivers of learning and cost reduction, which were mostly exogenous and whose effect would have been difficult to predict. Then it includes further exogenous factors with mostly negative impact.

Initial signs of fuel availability were a positive, international exogenous driver. System momentum that existed since the 1920s and the incumbent confidence it had fostered until the late 1960s were undermined by international and macro-economic events such as the energy crisis and the development of North Sea gas (Hannah, 1982). In the late 1950s and early 1960s, large natural gas reserves were found across the world and for the first time it became a viable fuel for electricity generation, triggering interest and initial developments (Riley et al., 1990). Before natural gas was first discovered in the North Sea in 1965, Britain had relied mainly on expensive 'town-gas' produced from coal or oil (Ministry of Power, 1965). By 1967 a national gas pipeline transmission system was under construction (Ministry of Power, 1967).

A strategically decisive exogenous driver that was difficult to predict and measure was technical versatility and cross-sectoral support. Unlike industrial gas turbines, turbojets underwent rapid development in the post-war period through significant aero-engine R&D programmes financed by government defence contracts; they were hosted mainly by GE and Pratt & Witney in the USA and Rolls-Royce in the UK (Williams and Larson, 1988).

[11] Total work activating the generator.

A sector-endogenous driver that turned out to have a highly positive impact was pressure on incumbent competitors. According to Hannah (1982), slow or absent progress in incumbent coal-fired steam turbine and nuclear power technology was the result of technical hurdles as well as economic, regulatory, and societal barriers, such as pressure from environmental interest groups and the regulation they induced, e.g. costly safety measures for nuclear and emissions regulations for coal.

The trend to deploy larger industrial combined cycle plant provided some learning-by-using benefits, which were compounded by delays in the delivery of large nuclear and fossil steam plant; in sum, the situation encouraged continued demand for gas turbines, particularly for base-load use (Wood, 1970).

On the other hand, there were also important factors within the UK electricity generation sector that had the effect of slowing down deployment and learning.

Institutional entrenchment was a sector-endogenous driver that slowed the course of technology adoption. As opposed to the economic principles that previously guided development, e.g. during the interwar years, the most powerful influences in the 1960s were institutional and political, i.e. the interests of the Central Electricity Generating Board (CEGB), Atomic Energy Authority (AEA) and British Gas Corporation (BGC) (Hughes, 1983). Routes to deployment were initially closed by institutional incumbents, whose deep-rooted rivalries and alliances posed a significant barrier to the entry of the unwelcome threat of CCGT. For instance, Russell (1993) reported that the CEGB was instructed to order all its plant from British providers and to procure all its coal domestically.

Given that a significant portion of forecasts are performed by government analysts or organisations commissioned by them, the level of government and institutional aversion towards CCGT in this decade explains, at least partly, the paucity of relevant forecasts from this period. Moreover, this would have increased the likelihood of a pessimistic view of CCGT plant.

3.2 The 1970s – macroeconomic shifts and pre-paradigm technology transfer

Learning and the beginning of competitive performance

This subsection introduces events that set CCGT on a more distinct development path leading to initial learning. These drivers are mostly endogenous and compatible with experience curve theory.

Proprietary technical development efforts from the late 1960s and into the early 1970s meant that by 1971 the recuperative gas/steam turbine plant[12] had become established primarily by Brown Boveri in Europe and GE in the US. Most plants had no supplementary firing and used single-pressure steam cycles (Wood, 1971).[13]

Islas (1999)reported that after the first oil crisis in 1973 electromechanical firms stepped up the techno-economic performance of CCGTs through R&D seeking economies of scope from existing industrial gas and steam turbine programmes. He identified amongst the most important R&D and mass production programmes the Steam And Gas (STAG) from GE, the Vapeur Et GAz (VEGA) from Alsthom, the Power At Combined Efficiencies (PACE) from Westinghouse, the programme of Brown Boveri,[14] which pioneered CCGT development and, finally, the programme of Krafwerk Union.

Larger gas turbine units were gradually developed specifically for power generation, which began incorporating advanced features from aero-engines (Spinks, 1976). Such plants using advanced gas turbines achieved increasingly high thermal efficiencies of around 48%, with the implication that environmental concerns would increasingly favour the technology due to its low emissions relative to coal-fired plant (Shorthouse, 1976).

Worldwide production of gas turbines increased five-fold to 5 GW per year by 1970; the growing revenue stream was used within the industry to accelerate further technology transfer from jet engines onto CCGT, notably air-cooled blades and high-temperature materials to enhance power output (Watson, 1997). Evidence of learning effects was that these developments resulted in a new generation of equipment that approached the 100 MW scale and was, as reported by Watson (1997), much more efficient; heat from the gas turbine exhaust was enough to obviate supplementary firing of the heat recovery steam generator (HRSG), allowing overall efficiency to exceed that of incumbent steam-only plants.

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[12] In reality, as Horlock (2002) emphasised, this CCGT configuration should be referred to as "open circuit gas turbine/closed cycle steam turbine combined CCGT plant."

[13] The 75MW 'Korneuburg A' recuperative plant, commissioned in 1961, was still the biggest European plant in service by the beginning of the 1970s; it had an overall low-calorific-value efficiency of 32.6% and did employ supplementary heating of the heat recovery steam generator (HRSG) (Horlock, 2002).

[14] ABB was later the result of the merger between Sweden's ASEA and Switzerland's Brown Boveri.

Industrial attitudes

The combined cycle was considered an unreliable power plant because of the conservative attitude of electricity firms (Islas, 1999). The inertia related to the reliance on the coal industry, the special position of British Gas Corporation (BGC) and the lobbying activities associated with these two incumbents presented significant institutional barriers to CCGT. These factors explain the slowing down of the spread of combined cycle for base-load generation. It was only after important socioeconomic and institutional changes, such as those described below, as well as significantly higher availability of natural gas that the GT family started to spread rapidly (Islas, 1999).

Macroeconomic forces

Although the techno-economic characteristics of CCGT for base-load were generally superior to those of incumbents in the mid-1970s, as Islas (1999)pointed out, CCGT had the handicap of using fuels such as kerosene and natural gas, which were either expensive or less abundant than the incumbents. A complication of that arose from the close control of gas fuel by incumbent actors such as the BCG, as reported by White (1990). The BCG had a statutory supply monopoly, would only approve supply for what it considered appropriate uses and it strongly opposed gas-fired generation; in fact, it actually declined a number of contracts for proposed industrial CCGT-based CHP plants (White, 1990).

The first oil shock of the early 1970s greatly curtailed the use of natural gas for electricity generation (Winskel, 2002). Although the price of gas rose far less than that of oil, policymakers considered it a scarce fuel with low supply security. The UK Department of Energy (1977) stated that gas prices should be set at a sufficiently high level to discourage "the wasteful use of a limited resource."

Government involvement

An important distortion of the deployment trajectory was introduced by international regulatory restrictions on the use of gas for power generation (Cleason Colpier and Cornland, 2002). In particular, European Directive 75/404/EEC on the restriction of the use of natural gas in power stations prohibited the use of gas for new power plants in the absence of exceptional technical or economic circumstances. In the USA, similar restrictions were imposed through the Power plant and Industrial Fuel Use Act of 1978 (PIFUA or FUA).

The magnitude and duration of state-financed military developments turned out to have paved the way for future phases in decisive ways. As mentioned previously, the USA annual military budget consisted of USD450 million between 1976 and 1986 (Williams and Larson, 1988). It is also true, however, that not all aeronautical advances were suited to the larger scale and robust demands of industrial gas turbines, e.g. turbojets remained too small and were not designed for continuous operation (Williams and Larson, 1988). Nevertheless, as summarised by Islas (1999), it was the advances in fluid dynamics, crystallography, development of new alloys suitable for superchargers, new techniques for numerical calculation, experimentation and manufacturing that eventually benefited CCGT.

The complexity achieved by the new CCGT plants demanded more sophisticated control, but the average availability for these plants was unacceptably low at less than 80% (Watson, 1997). In the USA, assistance from the Electric Power Research Institute (EPRI), which served as a focus for the needs of utilities, helped to redress the situation (Watson, 1997). Internationally, government intervention also appears to have been crucial during the years that followed the oil shocks of the 1970s. Government funded efforts to increase fuel efficiency, notably the Japanese Moonlight programme and the American High Temperature Turbine Technology programme helped CCGT proponents to endure the challenging decades and to make advances in, e.g., materials science (Watson, 1997).

This research confirms that the duration of the cycle of innovation, production (learning-by-doing), marketing and operation (learning-by-using) for technologies of this scale implies that most development efforts in one decade understandably only achieve their full potential in subsequent ones. The implication for future forecasting efforts is that it takes considerable time for sound technical developments to deliver their full potential in the face of a complex system context.

3.3 The 1980s – the international market and institutional transformation

In the years preceding the level of deployment during the dash for gas the forces that determined the rate of deployment, and thus learning, were predominantly sector-wide institutional motives that coincided with the result of many years of cross-sector corporate and government-funded research and development.

Methodological drivers

The pitfalls of basing experience curves on price as opposed to cost data were discussed briefly in Section 2.3. Findings by Cleason Colpier and Cornland (2002) following that method and reporting prices per kW of installed capacity are shown in Figure 3.1.

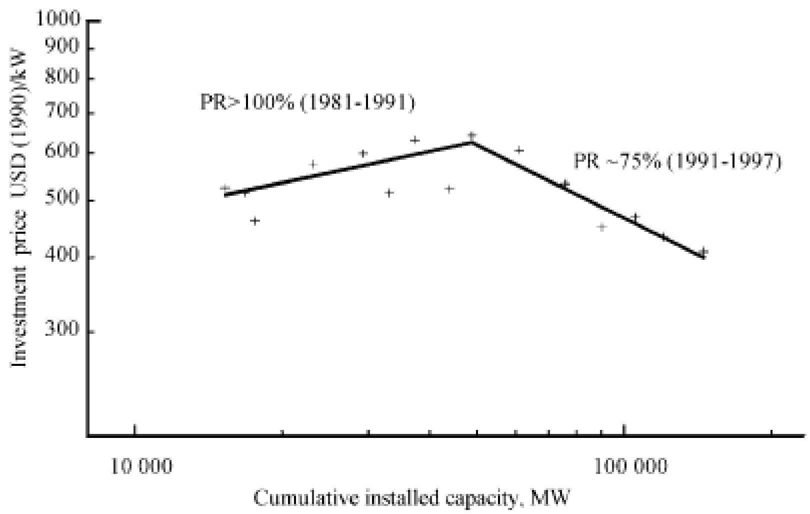

Figure 3.1 Experience curve for CCGT from 1980 until 1997. Source: Cleason Colpier and Cornland (2002)

Experience curves studied by Cleason Colpier and Cornland (2002) show that CCGT prices increased in the 1980s but eventually decreased in the 1990s linked to a learning rate of approximately 25%. Later review of the same data by Neij (2008) commented that the study had attributed the development of prices to a possible pricing strategy but concurred that further price reductions may be limited linked to a learning rate of 10% for future cost projections.

The IEA (2005) considered that "the [experience curve] methodology for calculating generation costs does not take business risks in competitive markets adequately into account" and that "it needs to be complemented by approaches that account for risks in future costs and revenues." These other factors play an important part in what causes the discrepancy between expected calculated costs and out-turns. They affect investment decisions and thus deployment and learning.

Ongoing technological improvement

This subsection presents the purely technical changes that appear to have been part of the development feedback loop that drove cost reductions for a number of decades.

The additional firing of the HRSG to approximately 760° C advocated in the late 1970s expecting higher overall efficiency was hardly deployed in subsequent decades; instead, by the mid-1980s, efficiency was improved by deploying dual-pressure steam raising (Horlock, 2002). And in terms of material science, clear evolution had taken place over several decades and by the mid-1980s the crucial materials had evolved from super alloys to directed super alloys and eventually to re-crystallised super alloys (Islas, 1999).

In technological comparison at the time when CCGT efficiency was hovering around 50% and plant sizes were between 120MW and 300MW incumbent steam-only plants were well into diminishing returns of efficiency improvements with increasing size and already at a scale between 800MW and 1300MW (Islas, 1999). It was argued by Hirsh (1989) that conventional steam plants were complex and unwieldy and introduced rigidity to the electricity system as well as diseconomies to generation costs (see Figure 2.6).

The repowering designs or maximally[15] fired plants became established by Brown Boveri throughout the 1980s. The Hemweg plant in the Netherlands increased its *efficiency* from 41.3% to 45.9% implying a 28% increase in power *output* by modifying the existing 500MW steam generation boiler to receive and fully fire the exhaust from a type 13E gas turbine carrying additional oxygen to promote further combustion (Pijkper and Keppel, 1986, Horlock, 2002). Turbine exhaust air at 534°C also obviated the need for preheaters common in previous steam-only plants (Pijkper and Keppel, 1986).

Within the challenging and changing regulatory and macroeconomic climate of the early 1980s, one of the crucial attributes of CCGT technology was that its improved performance enabled it to easily meet the new international regulations on emissions of oxides of nitrogen, sulphur dioxide, and dust. This attribute eventually helped to overcome problems of local social acceptability and, not least, to cut carbon emissions by more than 50% relative to conventional steam-only plant (Islas, 1999). This particular advantage was to play a central role in the developments of the subsequent decade (Watson, 1997).

Fuel availability and prices

The context at the beginning of the 1980s was characterised by uncertainty about the future of fuel supply. For instance in the USA, as a result of the Fuel Use Act only one CCGT was built between 1979 and 1986 (Smock, 1989). In the UK, the second oil shock of 1979 – 1980 reinforced the commitment of the electricity generation sector, for most of the 1980s, to nuclear power and coal-fired steam-only technology for all planned large-scale plant. This also reinforced the view that CCGT technology needed adaptation for use in conjunction with coal gasification before it could achieve significant deployment (Winskel, 2002).

Also in the wake of the second oil shock, new non-OPEC oil and gas reserves were developed and by the mid-1980s OPEC was divided and unable to restrict production

[15] In this arrangement, the natural gas boiler fuel is burnt with 15% excess oxygen content in the exhaust gas; the stack gas leaving the boiler still contains 3% oxygen.

amongst its members (Winskel, 2002). Furthermore, the limitation of demand through the 'Restrictive Directive' in Europe and the 'Fuel Use Act' in the USA led to oversupply of fuel that could not be burnt, which then caused the collapse of oil and gas prices in 1986, which remained low during the late 1980s and early 1990s (Riley et al., 1990). These events have been described as the "gas bubble" by Williams and Larson (1988) and as the "counter-crisis of 1986" by Islas (1999).

Policy decisions and changes to institutional inertia

Policy decisions and institutional changes can be described as endogenous to the power generation sector and they can affect the ability to forecast cost developments in very different ways. Institutional relationships and their inertia are relatively easily identifiable, leaving forecasters with the task of tracking exogenous developments that might upset them, although 'shocks' are by definition difficult to anticipate. On the other hand, policy decisions tend to change in response to widely acknowledged and traceable drivers.

In the first half of the decade, the expectations of the CEGB and important stakeholders were largely shaped by centralist management in response to the oil shocks in the 1970s. In fact, the traditional reluctance of the CEGB to exploit the potential of CCGT accumulated latent demand for the technology, which could only be satisfied through liberalisation (Baker, 1985). The interests of incumbent stakeholders were also reflected in the CEGB practice of prediction by extrapolation of the status quo in its 35-year forward planning even in the early 1980s (Baker, 1985).

During the late 1980s environmental regulations affected the competitiveness of fossil fuels; concerns about acid rain and global warming made pollution abatement a political priority in Europe. In 1988, the Large Combustion Plants Directive 88/609/EEC (now subsumed under the Industrial Emissions Directive 2010/75/EU) required reductions of sulphur dioxide emissions, of which coal-fired generation was a major source. Compliance required flue gas desulphurisation equipment, which increased capital and running costs; it became clear that using a cleaner fuel such as natural gas in smaller, shorter-lived, quicker-to-build, less costly plant was an advantageous compliance route for both SO_2 and CO_2 into the 1990s, i.e. into the 'dash for gas' (Islas, 1999, Watson, 1997, Winskel, 2002).

In conjunction with the objectives of the Public Utility Regulatory Policies Act (PURPA) of 1978, which included promotion of alternative forms of generation, regulators in the USA restricted the ability of utilities to cross-subsidise nuclear plant from other revenues (Winskel, 2002). At the same time, utilities were becoming increasingly averse to the risks of nuclear projects following the Three Mile Island incident in 1979 (Winskel, 2002).

The privatisation of the electricity supply industry in the late 1980s and early 1990s, particularly in the UK, coincided with dramatic changes in generation technology (Winskel, 2002). The PURPA rules in the USA set out two crucial requirements: utilities were required to set prices reflecting marginal costs of production and to buy power from efficient independent producers such as cogeneration plants, which made use of waste heat through combined cycles. As a result, 4.6GW of CCGT capacity were installed in the USA by 1985 (Williams and Larson, 1988).

A crucial non-technical development that contributed to deployment and thus learning was the privatisation of the electricity supply industry in the late 1980s and early 1990s. This was a critical driver of the dash for gas[16], which was subsequently reinforced by government-funded improvements in generation technology as well as renewed and plentiful fuel availability (Roberts et al., 1991).

Developments in the fuel and technology markets

Technology developments ought to have played a less dominant role in forecast variability given that they were part of a distinctive path, including government assistance, that began in previous decades. Developments in fuel availability and price, on the other hand, respond to exogenous forces from international markets and from other branches of economic activity, hence their susceptibility to introduce shocks.

The difficult beginning of the 1980s characterised by restricted, expensive fuel, institutional entrenchment and low demand for CCGT jeopardised the viability of the CCGT programmes at some major companies. Notwithstanding the withdrawal of some of the major companies from the industrial sector, the technology continued to develop and survived thanks to the significant versatility of application and the state-funded research that persisted during and beyond the 1970s (Watson, 1997, Winskel, 2002).

As the 1980s progressed, the combination of uncertain demand, environmental regulation, rising capital costs and a regulatory system which favoured independent producers, the high up-front investments and long lead times of large conventional plant became highly unattractive to utilities; for example, between 1974 and 1985, 93 nuclear and 41 coal-fired stations were cancelled (Williams and Larson, 1988). In contrast to the harsh context of the beginning of the decade, the higher levels of safety and environmental compliance achieved by small CCGT plants helped them to become a least-risk option by the late 1980s (Winskel, 2002).

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[16] Mainly because it enabled the entry of new market stakeholders and investors willing to take the risks and advantages of the new context of higher fuel availability and strong regulation restricting competing technologies.

After the US suppliers had addressed some of their reliability and acceptance problems and gained sufficient experience in the domestic market, they started marketing CCGT plant globally through their international affiliates initially in Japan and some developing countries such as Thailand and India helped by World Bank initiatives (Watson, 1997).

3.4 The 1990s and 2000s – transition to the present market landscape

Methodological drivers

Underlying gas price assumptions from different sources for the same year can introduce considerable variability. For example, the Canadian Energy Research Institute observed that its own natural gas price projection of CAN$11.43/GJ for the year 2010 (Walden, 2006) differed substantially from the range of CAN$4.84 – 7.44/GJ proposed by the IEA (2005). Given the high sensitivity of CCGT-derived LCOE to fuel costs (Section 2.3), this is possibly the most important methodological source of variability. The IEA (2004) also warned that "although it takes at least twice as long to build a coal-fired or nuclear plant [...] rising natural gas prices over the course of the Outlook are expected to reduce the attractiveness of this [CCGT] type of generation."

Underlying plant availability factors in different projections differ substantially, for instance 75% was widely used in the late 1990s whereas 85% was used in mid-2000s (IEA, 2005), although CCGT costs are far less sensitive to availability than to fuel costs.

Technology development

Between 1980 and 1995, the principal characteristic of industrial gas turbines was their accelerated technical improvement. For example, for Siemens gas turbines, the turbine inlet temperatures increased from 990°C to almost 1250°C, the rated output increased from 130 MW to 220 MW, the combined cycle efficiency from 45% to 55%, and the simple cycle efficiency from 32% to 36% (Islas, 1999).

Throughout the 2000s, the efficiency of CCGT approaching 60% due to high inlet temperatures and deployment of high-efficiency compressors had already far surpassed the efficiency of pulverised coal-fired plant of approximately 45%. Further increases of coal-fired generation efficiency would require a switch to IGCC technology but there still seems to be need for improvement of that technology (Junginger et al., 2008).

Looking into the future of endogenous technical development, it is worth bearing in mind that the technology is considered mature and R&D is predominantly performed by the leading OEMs. Since the early 2000s it has become increasingly difficult to improve the efficiency of one part of the system without incurring a thermodynamic penalty in another part (Horlock, 2002). In fact the highest efficiency level reported lately, in the context of all the R&D efforts and the boundaries for improvement, is 60.45% achieved by the Ingolstadt plant deploying a Siemens turbine (Hammer, 2011). It is because of this maturity that policies directed to R&D and market penetration for gas-fired CCGT are currently generally absent and future deployment might gradually include other fuels, such as coal, given its very large worldwide reserves (Junginger et al., 2008).[17]

Market reactions and expectations

Already at the beginning of the decade, the Energy Select Committee found that CCGT technology was enjoying a clear cost advantage over all other options (HoC, 1990).

The two technical advantages of CCGT that raised the interest of financiers during the early 1990s, subject to problem-solving of temporary reliability concerns, were confirmed by Roques (2007):

- The construction time is five years (sometimes over a decade) for nuclear power stations and four years for coal-fired stations, whilst it is only two years in the case of established CCGT plants.

- Plant technical life-times are generally assumed to be 40 years for nuclear and coal plants compared to 25 years for CCGT plants. Shorter project durations offer more possibilities to spread risks within portfolios. Moreover, the combination of low capital expenditure,[18] commercial discount rates of 15 to 20% (which shift the economics from fuel to capital) and short project life times (which imply a shorter return on investment cycle) is what makes investments in CCGT particularly attractive and ensures that amortisation is not a major concern.

The difference in financial assessment methods of prospective investments under liberalisation also had a significant impact on the timing and pace of CCGT deployment. The important difference is that commercial discount rates shift the economic sensitivity from fuel onto capital. That is one major reason why prior to privatisation CCGT would

[17] Coal-fired IGCC programmes are already in place or planned in several countries such as the Netherlands, Spain, the USA and Germany and it can be expected that several projects will incorporate carbon capture and storage (Junginger et al., 2008).

[18] One of the main advantages of CCGT.

have been less competitive, whilst after privatisation its modularity[19] and lower capital expenditure became a significant advantage (Winskel, 2002).

The financial and economic assessment played such an important role in determining which technology was deployed that it eventually influenced the design of the technology as well. For example, Scottish Hydro Electric stated that “rather than being designed to an engineering standard, plants were built to last an economic lifetime defined by the length of bank loans, fuel supply contracts and power purchase agreements.” In fact, they claimed that independent consortia “were ‘basically forced by the banks’ to adopt imported gas turbine technology” agreements (Winskel, 2002). The story of CCGT deployment since the 1990s provides the lesson that market formation and design must be taken into account when analysing and projecting cost trajectories.

Although the promise of fuel-switching flexibility seems to have been attractive for some multi-plant utilities, speculation about its benefits is likely to have introduced uncertainty in forecasts. In any case, the supposed fuel-switching flexibility was limited in practice by non-technical factors, e.g. environmental constraints for substituting gas, cost of alternative fuel storage, maintenance of passive fuel-switching equipment, short duration of profitable windows for switching that do not justify the costs of shifting operation from normal to alternative and back (National Grid Transco, 2006).

The period of increased demand and fierce competition of the early 1990s, in which commercial pressures to secure business coincided with the need to continue development led to delivery of units that had not completed a normal prototype testing cycle and undermined reliability (Section 2.2). One of the most prominent examples was the GE 9F model, which affected confidence in CCGT (Watson, 1997). Indeed, all major manufacturers had to devote significant efforts to “after-launch redevelopment” and problem solving and GE’s competitors, despite encountering their own problems, had a brief opportunity to catch up in terms of orders received (Bergek et al., 2008). Other examples were materials problems caused by overheating after 1996, which eventually forced ABB to compensate clients for losses and damages (Carlsson and Nachemanson-Ekwall, 2003).

Declining prices in the data studied by Cleason Colpier and Cornland (2002) definitely seem out of touch with this situation and, as commented by Neij (2008), the decreasing prices may well be more the result of pricing strategies in light of heightened competition than of genuine cost reduction in the corresponding magnitude.

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[19] The ability to build parallel CCGT composite modules (gas plus steam turbine) to achieve a desired overall capacity at different points in time was a way to manage capital investment.

From the mid-1990s onwards substantial market realignment has been underway (Junginger et al., 2008). Since the beginning of the decade, the international drive to replace old base-load generation with more efficient CCGT plants was quite dominant. Procurement decisions in an open market were based on economic performance, efficiency and dispatch curves. Decisions to invest in merchant plant were similar but also unable to foresee the overcapacity and fuel price changes that developed in the 2000s. One result was that total electric capacity growth since 1997 exceeded peak demand growth, i.e. three times as large. CCGT plants supplied 65% of that load, which meant a general decrease in capacity factor due to the cost increase of gas relative to coal and uranium (Bancalari and Chan, 2005).

Referring to future market segment-specific cost projections, Junginger et al. (2008) reported that specific scenarios for CCGT power plants are scarce. They also argued that pulverised coal-fired IGCC plants will likely capture an increasing share of the market in coming decades due to their promise of higher efficiencies and lower emissions of NO_x and SO_2. This sector-endogenous development is likely to determine much of the future evolution and technical learning of CCGT-assisted power plant technology.

An important implication for forecasters to note is that, summarising the opinion of several authors, e.g. Watson (1997) and Winskel (2002), the British dash for gas can be explained as the uncoordinated outcome from previously excluded international forces plus quick policy changes. Furthermore, industry analysts have argued that the attractiveness of CCGT had more to do with radical developments in the economic environment than with technological change (MacKerron, 1994).

Policy decisions, liberalisation and institutional changes

In Europe, Council Directive 91/148/EEC of 18 March 1991 revoking Directive 75/404/EEC on the restriction of the use of natural gas in power stations finally removed the fuel availability hurdle. In the USA, the removal of fuel restrictions that had been introduced by the Power plant and Industrial Fuel Use Act of 1978 (PIFUA) occurred in 1987.[20]

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[20] The way the international gas market shaped up included as supplying countries the Netherlands, with the highest flexibility, Norway medium and Russia preferring to deliver base-load with very small amounts of swing (Roques, 2007). Russia prefers take-or-pay, whereby the buyer is obliged to pay the contract quantity of gas even if he fails to take delivery in order to guarantee a cash flow for the seller.

Nevertheless, a natural gas bonanza did not begin automatically for the industry.[21] In 1990, an agreement was reached to redress discrimination by British Gas (BG) in supply and pricing to industrial users and discouragement of new entry. The agreement included new terms for liberalisation to expand supply, to guarantee access to newly developed reserves for independent suppliers and more transparent pricing (Winskel, 2002). In spite of the agreement BG imposed a 35% rise in industrial gas prices in 1991, arguing concern about coping with rapidly escalating demand, which affected the competitiveness of CCGT (HoC, 1991). Even though the Office for Electricity Regulation issued nine plant licences after the increase (OFFER, 1991), it is difficult to estimate what would have been the level of activity if the tactical move of BG had not occurred.

Coupled with the fuel price reductions of the late 1980s, the lifting of fuel restrictions was a key driver for deployment and learning but, in the opinion of Watson (1997), environmental regulations had a more decisive effect. Junginger et al. (2008) explained that increasing environmental regulations require plants to add equipment such as steam injection for suppression of NO_x emission and possibly Selective Catalytic Reduction (SCR) systems, which results in reduced output and efficiency. Hence, a cleaner fuel offered an economically attractive compliance alternative.

To privatise incumbent plants effectively, the UK Department of Energy (1988) proposed to divide the assets of the CEGB between two private companies, National Power and PowerGen, which had no statutory obligation to supply. The Department of Energy (1988) also planned to privatise the twelve Area Distribution Boards of England and Wales as independent distribution and supply companies, which later became Regional Electricity Companies (RECs).[22] The component companies that followed the dissolution of the CEGB acted quickly in 1989 to plan deployment of CCGT plant, which was

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[21] The precise trajectory of learning is also blurred by market design and fuel supply modality. For example, the independent consortia deploying CCGT consisted of RECs pooling their generation allowances and were only able to finance plant through non-recourse international loans against future revenue from power purchase agreements. They could only procure gas through back-to-back supply contracts with British Gas on a take-or-pay basis, which compelled independent plants to operate as base-load generation. In stark contrast, National Power and Powergen had the resources to secure gas from independent suppliers who were normally reluctant to sell on a non-recourse basis (House of Commons Energy Committee, 1992).

[22] The RECs were entitled to choose suppliers and to generation rights, which were eventually limited to 15 % of total demand within their area supply franchises to prevent them from becoming vertically integrated monopolies (House of Commons Energy Committee, 1990).

explained in the last-ever annual report of the CEGB (1989) due to the preference for smaller plants with short construction times and the lowest capital cost.

Elsewhere in Europe, following the full deregulation of the French electricity market in 2007 there has been increasing demand for CCGT plant to meet peak and intermediate-load, even in the absence of specific support policies (Junginger et al., 2008). The French case is an example of the pace of deployment where learning has been a function of the historical nuclear-rich energy mix and the pace of market reform. These two factors would need to be included in the analysis of cost trajectories in conjunction with technical learning.

Although there were reportedly over 14GW of installed CCGT capacity in Britain in 1997, which could soon exceed coal-fired generation, the government issued a moratorium on new CCGT schemes in an attempt to protect the remnants of the coal-mining industry (Buckley, 1997). Even if the moratorium only lasted until November 2000 (Edie.net, 2000), this is a particular type of intervention that can undermine learning and definitely change the pace of cost reduction trajectories at least in a national context.

For the purposes of cost projections to be used by private investors, Timera Energy (2011) has warned that it is important to monitor the risk to CCGT margins that could arise from government policy distorting market price signals such as the contracted output linked to the Capacity Market that is being implemented in the UK since the end of 2011. This mechanism removes some of the risks of generation plant but can affect how CCGT compares to other riskier kinds of generation in environmental, economic or safety terms.

4 Summary and conclusions

This section begins with a chronological summary of cost trends and the main drivers behind them. It then presents conclusions on the key lessons emerging for cost forecasting in CCGT-derived electricity in particular and for the forecasting of electricity generation costs in general.

4.1 Summary

The literature identifies four phases of technological development and learning including the period of constantly increasing costs starting in the mid-2000s. Analysts have identified variability in outcomes and some of the drivers behind them. This study has identified the variability in forecasts and the main drivers behind them. Key insights arise from the differences between those sets of drivers giving rise to the disparity between forecasts and outcomes. It is a clear future challenge to assimilate that disparity into forecasting methods in a way that can be informative also for other technologies.

The variability within forecasts as well as reported cost outcomes is the consequence of methodological, commercial corporate, geo-political and purely technical drivers. It is the influence of fuel cost, however, that was identified as the force that shaped the two main trends in forecasts.

Forecasting trends had a distinct turning point in 2005, largely due to the perceived influence of changes in fuel cost, namely:

- Forecasts published up until 2005 predicted that LCOE would decrease from a level close to 40$£_{2011}$/MWh in the year 2000 to, in average, just under 30$£_{2011}$/MWh by 2020 and then increase to return to 40$£_{2011}$/MWh by 2050. The driving assumptions were associated with the confidence in the constantly increasing efficiency and a conservative perception of the influence that exogenous drivers such as fuel cost could have.

- Forecasts published after 2005 projected a level of 80$£_{2011}$/MWh by 2015 rising in average to 105$£_{2011}$/MWh already by 2040. The driving assumption for that change of tone was the increasing weight assigned to fuel cost volatility. The great variability observed in post-2005 forecasts appears to be driven by a combination of expectation of higher fuel costs and the diversity of methods used to account for them. It is worth noting that although prices have not remained at the levels reached during the shocks of 2005 and 2008, volatility ranges have increased.

Cost outcomes within the evidence reviewed show that costs decreased from an average of 59£$_{2011}$/MWh in 1987 to reached their lowest point in the year 2000 at a level of 36£$_{2011}$/MWh, after which they increased again to 56 £$_{2011}$/MWh by 2010.

The main *exogenous* cost-reducing driver in this phase was the period of low gas prices in the late 1980s and early 1990s, which were followed by still relatively low prices into the year 2000 at approximately 1.53 £$_{2011}$/mmbtu for the UK and the USA (Alterman, 2012).

Endogenous drivers during the 1980s

- The main *endogenous* cost-increasing driver in the 1980s was the early-stage price umbrella created by the absence of meaningful competition. This was compounded by the ongoing improvements that were seeking higher efficiency but creating higher sophistication and complexity of the plats (i.e. there was lack of deployment of more mature products typical of later stages) (Cleason Colpier and Cornland, 2002).

- The main power-sector-wide driver that seems to have slowed down cost reductions was the more stringent environmental regulation (applicable to all fossil-fuelled technologies), which coincided with the period of restrictions on the use of fuel (Islas, 1999).

Endogenous drivers during the 1990s

- The main cost-reducing driver in this phase were indeed technical improvements leading to efficiency gains that, as previously mentioned, took place within the industry but were also partly exogenous, as they also took place outside the sector.

- Participation of more private companies in the electricity market in important countries resulting from deregulation, which then led to more competitive pricing for large CCGT contracts due to global competition among the leading suppliers.

- The achievement of shorter construction times, combined with the ability to deliver more standardised and replicable components, which were both particularly welcome by financiers.

The then auspicious combination of these drivers appears to have informed the moderately optimistic pre-2005 forecasts.

- A sector-endogenous cost-increasing driver was the hasty delivery to market of units of new models that had not completed a conventional testing cycle to secure the few available contracts at the time, which led to technical problems in the field that required significant remedial action (Watson, 1997).

- A less significant driver that would have helped undermine learning appears to have been a slight increase in complexity and the use of more expensive, advanced materials, which can be regarded as partly exogenous. As pointed out by Horlock (2002), as thermodynamic limits to efficiency gains are approached so are the limits to complexity, as virtually no one part of the system can be made more efficient without incurring efficiency penalties in another part.

Exogenous drivers during the 2000s

- The main cost-increasing driver during this phase was the continuous rise in both natural gas prices and their volatility. During the shocks of 2005 and 2008 prices reached approximately 7.97 £2011/mmbtu at the trading hubs in both the UK and the USA (Alterman, 2012).

An important aspect to bear in mind is that the achievement of deployment-dependent improvements in CCGT through learning-by-doing and learning-by-using has been a function of the versatility of the technology and its components outside the sector. Although not always readily transferable, the fluid dynamics, chemical and computational advances within aeronautics, oil extraction and industrial furnace applications allowed parallel learning to occur during times of low demand, adverse regulation and stiff competition. The ability to swiftly borrow that learning when demand resurged was crucial for the renewed viability of CCGT.

4.2 Conclusions

Use of experience curve versus engineering assessment

Observing the cost outcome trajectory for CCGT, particularly over the last four decades, and considering the effects of the main cost drivers in the same period, it becomes apparent that exogenous factors have overshadowed learning effects substantially. This would have rendered the reliance on learning rates during advanced-intermediate or almost-mature phases of technology development rather questionable. In any case, there seemed to be consistency in how actual costs turned out to be higher than forecasts making the relationship progressively predictable. Indeed, judging from the trajectory of forecasts it is clear that forecasters have begun to internalise that relationship by giving more weight to the main sources of cost increases. Nevertheless, even complementing the technique by accounting for business risks in future costs and revenues (IEA, 2005) still implies dealing with the variability of the natural gas, electricity and emissions markets.

Because in a substantial part of the forecast literature it is not clear whether engineering assessments, learning curves or a combination thereof was used, it is difficult to make general statements about the influence of different factors and the weight assigned to them by the experts involved.

Cognitive and methodological drivers of appraisal

Noticeable methodological differences in forecasts are related to the underlying assumptions for fuel cost, load factor and availability factor. In reality though, regulatory changes and fuel cost volatility have had the most influence in cost, deployment levels and comparative attractiveness. It is worth noting that in forecasts these factors have either been underestimated or their volatility has given rise to very different approaches to account for them.

At any rate, even if the extent of the influence of engineering assessments is difficult to quantify, it is conceivable that the same pressures applied to CCGT experts as to those of other technologies such as the need to (see also other case studies in this series):

- Demonstrate success of, and justify backing for, government support programmes;
- Be optimistic about economic performance to win contracts
- Be optimistic about the efficiency improvements underway
- Have the confidence that technical improvement will outweigh other factors.

Cost increases and deceleration of efficiency improvements were observed during the years when fuel use was restricted by policy; when fuel supply, electricity provision or both were not yet privatised; and when incumbents were entrenched within previous interests and practices. In a sense, it is not surprising that future forecasts will need to consider such factors and expect the terms and pace of deployment as well as in-country learning-by-using effects to be affected by them.

Factors likely to offset learning effects

Even though the versatility of parts of the technology has helped learning to endure difficult times, it can still be undermined by upward cost pressure from exogenous factors. At the same time, it is important not to underestimate the importance of the remarkable improvements that allowed CCGT to become the most efficient form of fossil-fuelled generation and without which exogenous factors would have obliterated any possibility of CCGT becoming attractive. Against this background, this sub-section summarises the key factors and their implications for future forecasts.

From the outset, the development of technological components of CCGT has been significantly influenced by socio-political drivers such as military efforts and the oligopolistic position of four major providers. The ensuing confidential sensitivity of cost data has been a constant feature of cost analyses in this sector.

The gradual inclusion of additional policy such as regulations of toxic pollutants as well as greenhouse gases implies a reciprocal gradual increase in complexity of forecasts particularly when elements such as the price of carbon emissions are subject to market uncertainties of their own.

The increasing proportion of intermittent renewable capacity will impinge on the load factors of generators with flexible output, notably CCGT, thereby shifting the growing risks associated with balancing supply onto them. Because deployment of CCGT will likely be predicated on its ability to service peak-load demand, it will be increasingly difficult for it to compete for the attractive margins available to other projects such as refurbishment of lower-efficiency, steam-only plant except for the eventuality of very high carbon prices.

The combination of characteristics that made CCGT investments attractive until the present, i.e. shorter construction times, shorter project life times, lower capital expenditure, is set to be affected in the future if the technology is deployed increasingly in coal-fired IGCC with CCS. Forecasters will likely be faced with two significant tasks:

i) To update their understanding of the breakdown of driving cost factors as well as the probability distributions of each one of those elements

ii) To account for the fact that old advantages in capital expenditure, project lifetime and construction times will be substantially eroded, practically setting the technology back onto a much earlier stage in the maturity continuum. In this respect, it is worth noting that price-cost interactions germane to earlier stages as noted by the Boston Consulting Group (1972) might arise.

One lesson worth bearing in mind for future forecasts with a global outlook is the effect that liberalisation of electricity markets (or its absence) had in countries with currently established markets. Understanding the proportion of the global market for CCGT likely to reside in emerging economies and the degree to which their markets are liberalised can inform insights into the likely pace of deployment. Nevertheless, efficiency improvements and reductions in capital expenditure are set to become more limited as explained above.

In essence, for gas-fired CCGT, fuel cost will remain the main source of variance for LCoE in future, albeit within an arguably more diversified and liquid market for LNG. For coal-fired IGCC, the advantageous project features of the gas-fired variant over the last two decades, e.g. quicker and cheaper to build, shorter-lived plant, will tend to be substantially eroded.

Final remarks

Since the 1990s the sources of uncertainty for costs of gas-fired CCGT as well as the limited room for improvement have become gradually clearer. Shorter construction lead-times and plant life-times have also helped to shorten the window during which consequential exogenous changes could happen.

Arguably, one of the two factors with the most influence over the impact of learning effects is the dominance of a single major cost component. The other most influential factor, also linked to fuel costs, is the exposure to geo-political forces. An important lesson for forecasters can be drawn from the past vulnerability to oil price shocks and the resulting constraining policies such as the restrictive directive and the fuel use act. In future, supply disruptions may become less likely due to the internationalisation of the LNG market. But price variations may still be subject to cartel-like activity and perceived scarcity.

Future uncertainty of the attractiveness of CCGT relative to more carbon-intensive techniques is likely to be dictated by the price trajectory for carbon emissions. For the cases where CCGT is deployed in coal-fired IGCC mode this will be an important source of sensitivity and attractiveness will also depend strongly on the performance of the carbon capture and storage technology.

In general, it is instructive to appreciate the implications of the breakdown of cost components, and the degree of uncertainty inherent to each component, for all generation technologies. For CCGT in particular the proportion of inherently exogenous costs that increase the exposure to uncontrollable variation is accentuated by the dominance of fuel costs.

In view of the findings of the study future forecasters would benefit from incorporating three insights in future calculations:

1 The difference between drivers for outcome variability and forecast variability stemmed from likely underestimation of exogenous, global, macro-economic factors

2 It is helpful to understand the exposure ratio amongst cost elements and the probabilistic significance of the exogenous sources of variation. Notably, understanding

the volatility of fuel and carbon price trajectories in addition to increased expertise in engineering assessment of the endogenous factors could deliver a fruitful approach.

3 It is important to consider the point of the technology maturity cycle in which the technology is situated at the time of forecasting as well as the extent of the time horizon into the future that is involved. Forecasts further into the future made during intermediate stages of technical development for highly exogenously exposed technologies are, clearly, the most vulnerable.

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