Electricity Generation Cost Study

Department of Energy Security and Net Zero

31 March 2025

FINAL REPORT

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ACRONYMS

Acronym	Detail
ACC	Air Cooled Condenser
capex	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CCR	Carbon Capture Readiness
CEPA	Cambridge Economic Policy Associates
CHP	Combined Heat and Power
CHPQA	CHP Quality Assurance programme
CO_2	Carbon Dioxide
CPS	Carbon Price Support
DESNZ	Department of Energy Security and Net Zero
DR	Decarbonisation Readiness
DUKES	Digest of UK Energy Statistics
EOH	Equivalent Operating Hours
EPC	Engineering, Procurement and Construction
ESIA	Environmental and Social Impact Assessment
ETS	Emissions Trading Scheme
EU	European Union
FID	Final Investment Decision
FOM	Fixed O&M
GB	Great Britain
GHD	Gutteridge Haskins & Davey Limited
GT	Gas Turbine
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generators
ISO	International Organisation for Standardisation
kW	Kilowatt
kWh	Kilowatt Hour
LHV	Low Heating Value
LTSA	Long Term Service Agreement
MW	Megawatt
MWh	Megawatt Hour
MW_{th}	Megawatt Thermal
O&M	Operations and Maintenance

Acronym	Detail
OCGT	Open Cycle Gas Turbine
opex	Operational Expenditure
PEACE	Plant Engineering And Cost Estimator
UK	United Kingdom
VOM	Variable O&M

1. INTRODUCTION

Unabated gas generation will remain an important part of the energy mix in Great Britain (GB) as the electricity system decarbonises. The Department for Energy Security and Net Zero (DESNZ) has appointed CEPA and GHD to assess the cost assumptions for electricity generation from new unabated gas projects, as well as the costs of extending the life of existing unabated gas projects in GB.

The generating cost assumptions used by DESNZ currently are based on a study conducted by Leigh Fisher for DESNZ in 2016.[1] This report is intended to provide updated cost assumptions and support DESNZ's wider assessment of the UK electricity generation system.

1.1. Scope of work

The goal of this analysis is to provide an updated set of electricity generation cost assumptions for a number of 'new build' unabated gas-fired power projects, including:

- Combined Cycle Gas Turbines (CCGT);
- Combined Heat and Power (CHP) plants;
- Open Cycle Gas Turbines (OCGT); and
- Reciprocating Engines.

This analysis was conducted in two key phases:

- **Phase 1**: CEPA engaged GHD to provide independent technical expertise and to develop cost estimates for capital expenditure (capex) and operation and maintenance (O&M) for both new-build projects and refurbishment options.
- **Phase 2**: CEPA designed a questionnaire to gather insights from stakeholders involved with the development of unabated gas projects in GB. The questionnaire was distributed to multiple stakeholders, and we received five responses. Follow-up interviews were conducted with four of the respondents, while one respondent declined to participate. A copy of this questionnaire is provided in Appendix D.

The final conclusions of this report are based on findings from both phases.

We have worked closely with DESNZ to define the technical and operating characteristics of each project for which cost estimates were developed in Phase 1. These characteristics are set out in the remainder of this report and in Appendix A. This report also examines the costs associated with refurbishing and repowering existing CCGT power plants that are reaching the end of their life.

It should be noted that there are certain exclusions to the scope of Phase 1 of this study. This includes decommissioning costs, which are thus not included in the cost estimates presented in this study. The scope also excludes analysis of future trends in generation costs or forecasting cost evolution for the generation options. Decommissioning costs and future trends are discussed in Phase 2 to the extent that the engagement with stakeholders provided insight on these topics.

1.2. Summary of Generation Options

Table 1.1 provides a high-level summary of each of the unabated new build gas-fired power projects ("generation options") that are in scope for this study. The selection of generation options was informed by both the technology

[1] LeighFisher (2016) *Electricity Generation Costs and Hurdle Rates: Non-Renewable Technologies*, available on gov.uk

configurations that were considered in previous DESNZ studies, as well as by CEPA/GHD experience of appropriate technology configurations.

Each project is assumed to be located in a generic unknown site in the UK. A generic site assumes that there are no site-specific considerations which could add exceptional costs, such as physical site constraints, unfavourable subsurface ground conditions, planning restrictions, limitations in local utility availability, flood mitigation requirements, additional noise mitigation requirements and contaminated land. The potential impact of these additional considerations on costs was explored as part of the engagement with stakeholders in Phase 2.

Table 1.1: Generation Study Options

Generation Option	Technology	Sizing	Annual Operating Hours
1	CCGT H Class	Approximately 1,700 MW	3,734 hours[2] per year.
2	CCGT in CHP configuration	Approximately 70 MW power and approximately 75 MW_{th} of useful heat (in the form of process steam) to a third-party consumer.	8,760 hours[3] per year.
3	OCGT <300 MW	299 MW	Separate cases where the plant operates for 500[4] or 1,500[5] hours per year are considered.
4	OCGT >300 MW	Approximately 770 MW	Separate cases where the plant operates for 500 or 1,500 hours per year are considered.
5	Reciprocating engines	20 MW	Separate cases where the plant operates for 500 or 1,500 hours per year are considered.

Source: CEPA and GHD in discussion with DESNZ

These generation options are intended to represent the following:

- **Generation Option 1** represents a flexible and efficient CCGT gas-fired power plant that provides reliable electricity to the grid system.
- **Generation Option 2** represents a CHP plant that generates electricity for export to the grid system and useful heat, in the form of process steam, for supply to the paper industry (in this case).[6]
- **Generation Options 3, 4 and 5** represent a peaking power plant, which normally operate for short durations when there is a high demand for electricity on the grid system. Based on GHD's recent experience, plants that are representative of Options 3 and 5 have typically acquired Capacity Market contracts.

[2] Equivalent to 43% of annual hours.

[3] Equivalent to 100% of annual hours.

[4] Equivalent to 6% of annual hours.

[5] Equivalent to 17% of annual hours.

[6] This choice was informed by CHP plants which are currently in use in GB.

- **Generation Option 3** represents an OCGT plant of under 300 MW which reflects the typical built design given the current Carbon Capture Readiness (CCR) requirements.[7]
- **Generation Option 4 and 5 are** broadly representative of the plant that may be built in future when the Government's proposed Decarbonisation Readiness requirements are introduced, which are expected to remove the 300 MW threshold.

1.3. Report Structure

The remainder of this report is structured as follows:

- Section 2 describes the approach followed in Phase 1 to estimate the cost of new build gas generation projects.
- Section 3 sets out the estimates developed as part of Phase 1 for the costs of the new build gas generation projects
- Section 4 sets out the estimates developed as part of Phase 1 for end-of-life refurbishment and repowering costs
- Section 5 sets out the findings from Phase 2 stakeholder engagement
- Section 6 provides overall conclusions.

[7] Since 2009, new build combustion power plants sized 300 MW or over in England and Wales have been required to demonstrate the capability to retrofit Carbon Capture and Storage (CCS) in order to decarbonise. Maintaining the plant capacity below 300 MW removes the complications associated with CCR requirements and the technical complexities of retrofitting CCS technology to a high temperature exhaust. Since CCR requirements were introduced, most consented OCGT projects have had a capacity of less than 300 MW.

2. PHASE 1: TECHNICAL APPROACH

This section sets out the technical approach used by GHD in Phase 1 to develop cost estimates for each generation option that is in scope for this study.

- We first describe the overall approach used to develop cost estimates for each new build generation option and for the cost of refurbishing and repowering existing CCGT plants.
- We then describe the modelling software used by GHD to inform this approach as well as the technical assumptions on plant load factors, availability, and performance degradation which are used in this study that feed into the final cost estimate.
- We finally describe the approach to developing capex and O&M cost estimates for each generation option.

All technical assumptions made in undertaking this study are presented in the Assumptions Log which is attached to this report in Appendix A. This Assumptions Log is based on a standard document format provided by DESNZ.

2.1. Overall Approach and Interpretation

We use a bottom-up approach to estimate the electricity generation costs for new unabated gas-fired power projects. This approach involves two main steps:

- GHD first develop thermodynamic models for each generation option using the Thermoflow software, specifically the GT Pro and Thermoflex programmes (as described in more detail in Section 2.2 below). This package is well regarded and is used extensively by project developers and consultants to estimate costs and optimise plan design. Based on these thermodynamic models, GHD utilise the Plant Engineering and Cost Estimator (PEACE) package within Thermoflow to develop initial cost estimates. PEACE provides an estimate of project costs for major equipment items, auxiliary systems, materials and labour based on conceptual level designs.
- GHD then verifies the cost estimates from PEACE using its own database, which is informed by recent experiences with similar projects in the UK and internationally. This database includes costs from over 30 gas engine sites with capacities ranging from 2 MW to 50 MW over the past five years, covering both construction and operation and maintenance costs.

We note that any approach to estimating the cost of new power generation technologies has inherent uncertainties. For example, equipment and service costs can vary based on supply and demand for new generation technologies. Additionally, external factors like the COVID-19 pandemic and the war in Ukraine can significantly affect supply chains and project delivery timelines and costs.

We highlight several broader factors that can cyclically influence the costs of new generation projects below:

- **Manufacturer discounts and premiums**. Gas turbine manufacturers may offer discounts for strategic reasons, such as entering new markets or boosting sales during low demand periods. Conversely, they might charge premiums for machines that have a proven track record or feature new, desirable technologies (e.g., high efficiency or flexibility).
- **Supply and demand**. Market forces have a substantial impact on power plant costs, often surpassing external inflation rates. Prices for gas turbines and reciprocating engines have fluctuated dramatically over the decades due to changing demand for these technologies. These fluctuations can cause quite dramatic movements in prices in both directions.
- **Site specific characteristics**. Some locations are more favorable for power plant construction than others. Projects on greenfield sites with good subsurface conditions and easy access to fuel and infrastructure tend to have lower build costs compared to those on remote brownfield sites with poor conditions or

potential contamination. Each project in this report is assumed to be on a generic site in the UK, without accounting for specific site-related costs, as noted in Section 1.

The bottom-up cost estimates which are developed for this report are all based on a 2024 delivery date. That is, the capital cost estimates are based on contract execution in 2024 and similarly, the operation and maintenance cost estimates (including fixed and variable components) are also based on delivery in 2024. This report does not attempt to forecast how costs may evolve over time in response to future learning rates or to the wider factors outlined above – i.e., factors influencing the supply and demand for different generating technologies.

We note that stakeholders highlight some of these factors as part of our engagement in Phase 2. However, to address this inherent cost uncertainty in Phase 1, we also develop a range of low, medium, and high estimates for costs and related technical parameters. GHD apply a cost multiplier, that reflects the range of costs associated with each technology, to a typical "median" cost in order to develop the low and high estimates. These low and high estimates aim to illustrate the potential range of costs that might be seen in the market.

Finally, we note that the technical assumptions and cost estimates developed for this report are presented in Section 3 alongside values published in the 2016 report by Leigh Fisher. The inclusion of values from the 2016 report is for reference purposes and to illustrate how assumptions and cost estimates differ between reports. Where cost estimates from the 2016 report are shown, we have not adjusted them for inflation or price movements over time. As noted, costs may change in response to various factors that do not necessarily follow a single economy-wide inflation measure, such as the CPI.[8] Applying an inflation adjustment would therefore assume that relevant prices have changed in line with the chosen price index, which may not be accurate.

2.2. Modelling Software

GHD is licensed to utilise the commercial thermodynamic modelling software package developed by Thermoflow Inc. The software is well regarded and widely adopted by consultants and project developers and incorporates a suite of programmes that can model various types of plant to varying levels of detail. Specialists within GHD are highly trained and experienced in using the Thermoflow software allowing them to conduct comprehensive process modelling tasks for simple cycle GT, CCGT, CHP power plants and reciprocating engines, their subsystems and individual components.

GT Pro and GT Master are two software packages within the Thermoflow suite of programmes that have been specifically developed to model gas turbine (GT) plants. These software packages allow a system based top-down development of a power plant model and are ideal for the design and optimization of GT-based power plant. These software packages also offer a detailed estimate of plant costs that is particularly valuable for feasibility studies, providing an effective and efficient method of comparing approximate cost and performance data, both design, and off design, for various plant configurations and options. In addition, GHD's specialists also have access to Thermoflex which affords an even greater level of refinement allowing individual plant to be designed and assessed.

GHD have developed thermodynamic models of the generation options using GT Pro, GT Master and Thermoflex. GT Pro was used to fix the design of the gas turbine plant and Thermoflex was used for the design of the reciprocating engine plant, based on the set of agreed assumptions (Appendix A), including:

- Ambient conditions;
- Number and model of gas turbine and engine;
- Fuel (natural gas);
- Steam cycle type (number of pressures, reheat/non-reheat, condensing, non-condensing) and steam parameters;

[8] We note that cumulative CPI inflation between 2014 and 2024 is 33.4%.

- Configuration (multi- and single-shaft, number of steam turbines); and
- Cooling system type.

The Thermoflow software includes a large technical library of gas turbines and engines for which benchmark performance is provided, based on mathematical thermodynamic models and performance data supplied by Original Equipment Manufacturers (OEMs). The latest version (version 32) of the Thermoflow software, updated in July 2024 was used for this study.

Where necessary, the models generated in GT Pro were imported into GT Master, the off-design programme. This was required to estimate the performance of the CHP plant in its different operating modes. Where necessary, the models generated in GT Pro were imported into GT Master, the off-design programme. This was required to estimate the performance of the CHP plant in its different operating modes.

Gas turbine performance, and the CCGT plant as a whole, is affected by ambient conditions, particularly ambient temperature and barometric pressure. Reciprocating engine performance is far less susceptible to ambient influences. Performance is usually quoted based on ISO conditions (15°C, 1013 mbar, 60% relative humidity). However, in the Leigh Fisher report of 2016 a lower temperature of 11°C was used to better reflect UK conditions. For consistency, GHD have also used an ambient temperature of 11°C.

2.3. Plant Load Factor

The plant load factor is a measure of the average power output, relative to the maximum power output measured over a full year.

The Digest of UK Energy Statistics (DUKES) published by DESNZ provides statistics on electricity generation in the UK. It was reported that in 2023 the plant load factor for CCGT plant (represented by Generation Option 1) was 33.2% (down from 41.2% in 2022). This reflects the changing role for CCGT plant in the UK electricity system, moving away from providing baseload operation to the provision of flexible backup that supports increased wind and solar power integration on the network. For consistency with DUKES, GHD assume that the CCGT option will typically be dispatched at around 80% load when operating, to provide flexible backup for the grid. Over the course of one year (accounting for availability) this would be equivalent to the DUKES 33.2% load factor.

The dispatch of CHP plants (represented by Generation Option 2) is normally driven by the requirement for 'heat' (process steam) by the end user. For the purpose of this study, it is assumed that process steam will supply the paper industry. As such, steam is typically required at a constant rate on a continuous basis and therefore plant dispatch at 100% load is assumed.

Peaking power plants (represented by Generation Options 3-5) normally operate for short durations when there is a high demand for electricity on the grid system and are typically dispatched at 100% load during such periods to maximise revenue. Typically, the plant load factor will have a negligible impact on variable O&M.

The assumed load factor for each of the generation options are in Appendix A.

2.4. Plant Availability

The plant availability factor is a measure of the number of hours per year that the plant is available to generate electricity. Availability is reported as a percentage figure relative to the total number of hours in a year (i.e. 8,760 hours).

Availability takes into account the number of hours per year in which the plant will be offline (unable to generate electricity), due to:

- Planned inspection and maintenance activities which are normally carried out in accordance with the original equipment manufacturer's recommendations.
- Unplanned (or forced) maintenance activities which are carried out in response to a breakdown or unexpected failure of equipment.

The annual availability of each generation option will vary year on year, according to the maintenance regime and the age of the asset. For this study, an average through-life availability, accounting for both planned and unplanned maintenance outages, was applied. In practice, the expected availability of a plant does not always translate into operating hours (i.e. the plant might be available, but not dispatched). The load factor is a measure of the average load whilst the generator is operating. If the VOM is dominated by hours based scheduled maintenance, a lower load factor will result in a higher VOM (i.e. less MWh generated per maintenance inspection or outage).

These assumptions are described for each generation option in Appendix A.

2.5. Performance Degradation

This section separately describes the assumptions that have been applied to performance degradation (in terms of power output and efficiency) for GTs and reciprocating engines.

Gas Turbines

GT performance is subject to degradation over time. Performance degradation is principally caused by fouling (the adherence of particles to compressor/turbine aerofoil surfaces), erosion wear of rotating clearances and corrosion (the loss or deterioration of material caused by chemical reactions). These factors ultimately have a negative impact on power output and efficiency.

It is widely accepted that degradation of power output and efficiency is accrued rapidly within the first few thousand hours of operation. The rate of degradation then significantly reduces over the remaining life of the equipment. Degradation can be categorised as follows:

- Non-recoverable – a permanent loss of power output and efficiency; and
- Recoverable – a relatively small proportion of the degradation that can be temporarily recovered by undertaking maintenance and replacement of components.

The previous study produced by Leigh Fisher[9] reportedly accounted for online and offline compressor washing of the gas turbine. In GHD's opinion the performance benefit of compressor washing is relatively limited and short lived. As such it has not been considered in this study.

Other major equipment items (the heat recovery steam generators (HRSG) and steam turbine) in the combined cycle also suffer degradation, but with a relatively lower impact on overall plant performance compared to the gas turbine.

The assumed performance degradation applied to each GT generation option is included in Appendix A.

Reciprocating Engines

Reciprocating engines are not susceptible to degradation in the same way as GTs. Subject to the appropriate and timely undertaking of maintenance activities, it is reasonable to expect that power output would be maintained with limited degradation in efficiency.

The assumed performance degradation applied to reciprocating engine performance is included in Appendix A.

2.6. Project Costs

This sub-section describes the approach used to develop capex and O&M cost estimates for each generation option. All costs provided in this report are referenced to 2024 prices.

2.6.1. Overview

For each Generation Option, cost estimations were produced covering:

[9] LeighFisher (2016) *Electricity Generation Costs and Hurdle Rates: Non-Renewable Technologies*, available on [gov.uk]

- project development;
- construction; and
- operation and maintenance.

Where appropriate and for consistency, GHD have adopted similar assumptions as for the previous study produced by Leigh Fisher. All assumptions are presented in detail in Appendix A. In the following sections, we provide an explanation and basis for the project cost aspects that have been estimated.

2.6.2. Project development costs

Project development costs relate to expenditure incurred by project owners/developers prior to the Final Investment Decision (FID) and execution of delivery contracts.

Project development costs typically include the upfront costs in site selection studies, concept design and site surveys, ground investigations, an environmental and social impact assessment (if required), together with the efforts in securing planning permission, a fuel gas connection, and a grid connection.[10]

For the purpose of this project, we have estimated project development costs as a whole cost, without breakdown into specific aspects. It is acknowledged that previous studies have apportioned costs to specifics, such as regulatory and licensing aspects. The project development costs in this study are estimated on the basis of a percentage of the total EPC cost, based on GHD's experience and in-house project database.

2.6.3. Construction costs

Construction cost estimates are based on Engineering, Procurement and Construction (EPC) projects. Bid prices for power plant are subject to influences such as optimisation, market pressure, bidder attitude to risk, bidder order books, possible requirement to offer discounts to obtain references for new models and bidder enthusiasm for the project. To develop enhanced cost estimates, GHD has utilised the PEACE programme included in the Thermoflow package and GHD's own internal database of project costs.

The PEACE software is a well-established tool that generates equipment lists and capital cost estimates. It is regularly updated by the software developers and has been used as the basis for capital cost estimates. GHD's specialist plant modeller's have modified the factors with PEACE to allow for local site requirements and conditions in the GB power generation market.

GHD has used experience of gas turbine and engine projects from recent years to validate all estimated costs and update costs derived from PEACE. The reference date for prices produced by PEACE is July 2024. It is recognised that there is much volatility in world markets. Where required, historic prices for European projects have been adjusted to present value by reference to the change in producer prices since the start of the reference project, based on a comparison of the producer prices index (PPI) for the Euro area[11]. PPI was used for this project as it more accurately reflects the costs producers receive. It includes costs associated with labour, raw materials and energy rather than standard inflation rates.

Our low, medium, high scenarios reflect the range in construction costs that we have reviewed.

Infrastructure costs capture the cost of gas and electrical power connections. These costs are site specific and therefore difficult to assess. For consistency with the previous reports, GHD have used costs in the previous reports as a reference and adjusted them for plant capacity, gas consumption and price indexing.

The assumed connection distances under the Low, Medium, and High scenarios are illustrated in the Table below.

[10] This does not include the cost of building the physical connection asset.

[11] Available at https://tradingeconomics.com/euro-area/producer-prices

Table 2.1: Connection Distances

Power Connection Distances (km)	Low	Medium	High
Generation Option 1: CCGT H Class	5	10	20
Generation Option 2: CCGT in CHP Configuration	5	10	20
Generation Option 3: OCGT<300 MW	5	10	20
Generation Option 4: OCGT>300MW	5	10	20
Generation Option 5: Reciprocating Engines	1	5	15

Source: GHD/CEPA adopted from Leigh Fisher (2016)

2.6.4. Fixed O&M costs

Fixed O&M encompasses costs that are incurred regardless of the amount of electricity the plant generates. The principal cost factors considered in this study include insurance, management and administrative fees and staffing cost. Insurance costs are estimated as a percentage of the EPC cost.

Fixed Financing costs are not captured within the Fixed O&M cost estimates that are presented in this report. This is consistent with the approach taken in the 2016 Leigh Fisher report which also excluded financing costs. Land lease may also feature in the fixed O&M costs but for the purpose of this study it has been assumed that land would be procured outright rather than leased and hence related costs are factored into the capex. The breakdown of costs with and without land costs can be found in Appendix C.

2.6.5. Variable O&M costs

Variable O&M costs encompass expenditure that is subject to variation according to the amount of electricity produced, the operating regime and the respective technology. The Variable O&M costs presented in this report relate to plant maintenance costs which captures planned routine maintenance inspections and breakdown maintenance in response to an unexpected failure.

For CCGT plants, maintenance outages are focused on the primary equipment items: the gas turbine, HRSG and steam turbine generator. In general, the maintenance regime is driven by the gas turbine with works on the HRSG and steam turbine generator being undertaken coincident with the gas turbine outage.

The gas turbine maintenance regime (in both CCGT and OCGT plant) is driven by the accumulated number of operating hours and the number of starts/stops of the unit. The types of maintenance outage typically include:

- Minor inspections - being a short duration inspection of the equipment to confirm the conditions and identify any unexpected issues that may have arisen. A minor inspection is broadly carried out every 8,000[12] hours.
- Hot gas path inspections - being a relatively long duration inspection of the equipment and replacement and/or repair of components in the hot sections of the unit. A hot gas path inspection is broadly carried out every 24,000 hours[13].
- Major overhauls – being the longest outage duration, involving a full inspection of the equipment and replacement and/or repair of components throughout the unit. A major overhaul inspection is broadly carried out every 48,000 hours.[14]

[12] Although 8,000 hours is equivalent to approximately 11 months, the time between maintenance outages depends on the assumed operating hours per year.

[13] 24,000 hours is equivalent to approximately 2.7 years (33 months).

[14] 48,000 hours is equivalent to approximately 5.5 years (66 months).

For reciprocating engines, the maintenance regime is driven by the accumulated number of operating hours of the unit. The types of maintenance outage broadly include:

- Routine maintenance –short duration inspections of engine components to check for wear and tear together with regular replacement of lubricating oil, air filters and oil filters. Routine maintenance ranges from daily/weekly checks of equipment to oil/filter changes every few thousand hours.
- Top-end overhaul - moderate duration inspections of the equipment including replacement and/or repair of components like cylinder heads and turbochargers. A top-end overhaul is broadly carried out every 20,000 to 30,000 hours.[15]
- Major overhaul - being a moderate duration inspection of the equipment including replacing pistons and liners, inspecting the crankshaft, and replacing bearings and seals. A major overhaul is broadly carried out every 72,000 hours[16].

GHD has factored the required maintenance outages for each technology into the average availability for each generation option. The average costs associated with the maintenance activities have been derived on the basis of GHD's knowledge and experience in other similar generation projects in the UK. Fixed fee and staff and administration costs are included in fixed O&M costs and the variable costs included general variable charges and expenditure, and the cost of hours based scheduled inspections.

[15] Although 20,000 to 30,000 hours is equivalent to approximately 2.3 (28 months) to 3.4 (41 months) years, the time between maintenance outages depends on the assumed operating hours per year.

[16] 72,000 hours is equivalent to approximately 8.2 years (98 months).

3. PHASE 1: COST OF NEW UNABATED GAS GENERATION

This section sets out the cost estimates for each new build generation option based on the Phase 1 approach described in Section 2. In all cases, a low, medium, and high estimate is provided. A comparison between these Phase 1 estimates and the cost estimates developed by Leigh Fisher in 2016 is also provided for reference. The estimates from the Leigh Fisher are provided in 2014 prices, as provided by Leigh Fisher in their 2016 report.[17]

3.1. Generation Option 1: CCGT H Class

Description

In a CCGT power plant, the gas turbine is the ‘prime mover’ and primary electrical power generator. A heat recovery steam generator (HRSG) recovers the waste heat in the gas turbine exhaust to generate steam which is delivered to a steam turbine generator to produce more electrical power.

For this generation option, a ‘H’ class gas turbine is assumed. This represents the largest and most efficient gas turbine model that is commercially available. The concept is based on two gas turbines, each with HRSGs and a single steam turbine generator in a multi-shaft arrangement.[18] The main cooling system is based on air cooled condenser (ACC) technology.

A triple pressure re-heat steam cycle is adopted, which is typical for ‘H’ class CCGT plant. The triple pressure re-heat steam cycle enables more heat to be recovered from the gas turbine exhaust (compared with other designs) permitting increased power generation (from the steam turbine) and greater overall cycle efficiency, but with a higher capex. This reduces the specific fuel consumption and cost, and the specific CO_2 emitted.

Key project timings

GHD’s assessment of project timings is provided in Table 3.1. Values drawn from the 2016 Leigh Fisher study are also included for reference.

Table 3.1: Generation Option 1 – Key project timings

Period (Years)	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Project development	2.0	2.3	5.0	2.0	2.3	5.0
Construction	2.0	2.5	3.0	2.2	3.0	3.2
Operation	20	25	35	20	25	30

Source: GHD analysis and Leigh Fisher (2016) – Table 4

Project development time is affected by market forces, planning requirements, government policy and system requirements. Whilst there may be some outlier projects, GHD consider the previous estimates to be reasonable and are unchanged.

Construction time is affected by the number of turbines, the general plant configuration and the cooling system. For the low estimate, GHD consider 2 years (24 months) to be an aggressive programme; therefore, low estimate for construction time was increased to 2.2 years. GHD consider that a typical (medium) value for this type of construction programme to be 3 years (36 months), representing an increase to the previous estimate of 2.5 years (30 months). The high value is 3.2 years (38 months), compared to the previous estimate of 3 years (36 months).

[17] To avoid misrepresenting the estimates, we have not adjusted them for inflation. An inflation adjustment would entail the assumption that relevant prices have changed according to inflation which may not hold.

[18] CEPA understand that a multi-shaft arrangement is currently being offered by all major manufacturers and is therefore an appropriate choice to represent a generic CCGT configuration.

While GHD considers construction to take longer than in the previous study, the high estimate is only two months greater. This is based on GHD's experience of easing in supply chain pressures after the disruption experienced in past few years. Appropriate management of lead times can also shorten the construction period.

Construction time is affected by the number of turbines, the general plant configuration and the cooling system. For the low estimate, GHD consider 2 years (24 months) to be an aggressive programme, so have increased the duration 2.2 years. GHD consider that a typical value for this type of construction programme to be 3 years (36 months), with a high value of 3.2 years (38 months). The low, medium, high estimates are a reflection of realistic construction timelines, based on project proposals for similar projects within the last five years.

The operations period is dictated by the original design life of the asset and how the plant is operated and maintained in relation to the design intent. In GHD's experience, the operational life of a CCGT is nominally 25 years but this can be shortened in certain circumstance. The operational life can also be extended, within certain limits. This is discussed further in Section 4. GHD considers an upper limit of 30 years of operation to be appropriate for this study.

Plant performance

As discussed in Section 2, GHD uses GT Pro to thermodynamically model the CCGT plant. The heat balance diagram for this option is shown in Appendix B.1. This diagram represents performance in the new and clean condition. GHD's assessment of the degraded performance is provided in Table 3.2. Values drawn from the 2016 Leigh Fisher study are also included for reference.

Table 3.2: Generation Option 1 – Plant Performance

Parameters	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Net power output (MW)	1,190	1,200	1,210	1,663	1,666	1,668
Net efficiency (%, LHV)	58.8	59.8	60.7	60.2	60.2	60.3
Availability (%)	92.3	93.0	93.6	93.0	93.0	93.0

Source: GHD analysis and Leigh Fisher (2016) – Table 5

GHD applied typical technical parameters for the design of the steam cycle, and it did not attempt to optimise the overall performance in the model.

A Low, Medium and High scenario was applied for performance degradation. The evaluation of degradation was based upon typical OEM degradation curves and the anticipated accrual of operating hours per annum over the life of the project. The Low figures in Table 3.2 are based on the High degradation assumption resulting in the lowest power output and efficiency, which will ultimately result in a higher cost of generation (£/kW). The opposite applies to the High scenario, with Low degradation resulting in relatively higher power output and efficiency.

For plant availability, GHD have assumed an average through-life figure in our assessment. The average through-life figure accounts for there being longer duration maintenance outages in some years and shorter outages in others.

It should be noted that operating hours (Equivalent Operating Hours, EOH) trigger maintenance outages (and unavailability), rather than degradation. That is, a high degradation scenario (low estimates) does not lead to lower availability.

As shown in Table 3.2, the output and efficiency estimates have been updated to reflect the performance of the largest H Class technology that is presently available. We understand that the 2016 Leigh Fisher study based its option on 2 x 600 MW single-shaft CCGT units (with a GT and ST connected on a common shaft to a single generator). Based on GHD's recent engagement with original equipment manufacturers, the single shaft configuration is not currently offered. The choice between single- and multi-shaft will have a very small effect on cost and performance; the selection decision is affected by other parameters such as site layout, operational requirements and owner preference. The multi-shaft option was selected as it is generally available from all OEMs.

Capital costs

Low, Medium and High capital cost estimates based on the Phase 1 approach are summarised in Table 3.3 below. The background information and basis for the estimates is presented in Appendix C. Values drawn from the 2016 Leigh Fisher study are also included in Table 3.3 for reference. These capital cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.1.

Table 3.3: Generation Option 1 – Development and Capital Costs

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Project development (£/kW)	5.6	11.2	17.2	7.2	16.7	19.6
Capital cost (£/kW)	439	516	593	510	601	691
Infrastructure (£m)	7.5	15.1	30.2	11.9	23.8	47.6

Source: GHD analysis and Leigh Fisher (2016) – Table 6

Project development cost represents expenditure by the developer prior to FID and includes pre-licensing and regulatory cost, as per the 2016 Leigh Fisher study, as a single line item. The capital cost estimate is based on a nominal capacity of 1,700 MW and a turnkey EPC[19] delivery strategy. The infrastructure costs include for the fuel gas connection and electrical grid connection works.

A breakdown of the capital costs based on the Medium cost estimate is provided in Table 3.4 below.

Table 3.4: Generation Option 1 – Capital Cost Breakdown

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Specialised equipment Including: Gas turbine package, steam turbine package, heat recovery boiler, air cooled condensers, CEMS, DCS, transmission and generating voltage equipment.	58.1%	349
Other equipment Including: Pumps, tanks, heat exchangers, emergency generators, medium and low voltage equipment.	3.3%	20
Civil Including: Site work, excavation and backfill, concrete works and any roads, parking and walkways.	8.1%	49
Mechanical Including: On-site transport and rigging, equipment erection and assembly and piping.	15.5%	93
Electrical Assembly & Wiring Including: Controls, assembly and wiring.	5.6%	34
Buildings & Structures Including: Turbine hall, administrations and control rooms, water treatment system, and a guard house.	4.6%	28
Engineering & Plant set up	4.8%	28

[19] Turnkey EPC is a type of contract, where the contractor is responsible for the project from inception to completion (design, procurement, construction, commissioning and hand-over of the project to the developer).

Source: GHD analysis

Operation and Maintenance cost

Low, Medium and High O&M cost estimates based on the Phase 1 approach are summarised in Table 3.5 below. The background information and basis for the estimates is presented in Appendix C. Values drawn from the 2016 Leigh Fisher study are also shown for reference. These post-construction cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.1.

Table 3.5: Generation Option 1 – O&M Costs

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	9,770	12,240	14,670	13,310	15,630	17,950
Variable fee (£MWh)	1.22	1.43	1.83	3.78	4.44	5.10
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 8

Fixed and variable O&M costs are based on in-house GHD long term service agreement (LTSA) estimates and project experience, and by applying the assumed hours and starts for the Generation Option.

The O&M costs, which are referenced either to the MW of capacity or MWh generation, take account of performance degradation. The degraded costs are effectively higher than undegraded costs, because of the reduced capacity of the plant, compared to the 'new and clean' condition.

The variable costs that are estimated for this report are influenced by fewer operating hours and a greater number of starts relative to the electricity generated relative to the report by Leigh Fisher (2016). The annual operating hours and the number of starts influences the schedule of maintenance outages over the life of the plant. This reflects the higher share of renewable energy on the grid and the decreasing dispatch of CCGT plant since 2016.

3.2. Generation Option 2: CCGT in CHP configuration

Description

In a CHP plant, electricity is generated for export and useful heat is provided (in the form of process steam), typically to a third party, for process use.

For this generation option, the CHP plant is based on CCGT technology. This generation option is based on a similar CHP project located in the UK, which provides process steam to a neighbouring paper and pulp mill. The concept comprises a single industrial gas turbine with HRSG, to generate steam which is delivered to a single back-pressure (non-condensing) steam turbine. A single pressure cycle was adopted, which is typical for relatively small CCGT plant. The HRSG incorporates supplementary firing to increase steam generation for enhanced power generation and process steam supply, which ultimately serves to boost the CHP efficiency.

We note that Generation Options 1 and 2 cannot be directly compared to other options in this report as the specification for these options are too dissimilar. While Generation Options 1 and 2 both include gas turbine and steam turbine technology, Generation Option 1 generates electrical power only, while for Generation Option 2, the equipment was selected specifically to produce the correct quality and quantity of steam (heat generation). The electrical generation, whilst maximised was a secondary concern. The capacity of these options also differs greatly.

While the plant concept for this option was selected based on discussions with DENSZ, it should be noted that there are several possible configurations for CHP plants, making comparison between different CHP plants difficult.

Key project timings

Our assessment of project timings is provided in Table 3.6. Values from the Leigh Fisher study of 2016 is also shown for reference.

GHD expect the project development, construction and operation timings for the CHP option to generally align with those of a CCGT plant. The assumptions made in the previous study are generally reasonable and are therefore largely unchanged, however, regarding operational life, GHD consider an upper limit of 30 years to be appropriate, as opposed to 35 years in the Leigh Fisher study of 2016. In GHD's experience plants are typically designed for an operational life of 25 years, but depending on the condition of the plant, the operational life can be longer.

Table 3.6: Generation Option 2 – Key project Timings

Period (Years)	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Project development	2.0	2.3	5.0	2.0	2.3	5.0
Construction	2.0	2.5	3.0	2.0	2.5	3.0
Operation	20	25	35	20	25	30

Source: GHD analysis and Leigh Fisher (2016) – Table

Plant performance

GHD used GT Pro to thermodynamically model the CHP plant. The heat balance diagram for this option is shown in Appendix B.2. The heat balance diagram represents performance in new and clean condition. Our assessment of the degraded performance is provided in Table 3.7. Values from the Leigh Fisher study of 2016 are included for reference.

Table 3.7: Generation Option 2 – Plant Performance

Parameters	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Net power output (MW)	146	168	190	68.5	68.6	68.7
Net electrical efficiency (%, LHV) [20]	37.9	38.2	38.5	40.34	40.38	40.42
CHP efficiency (%, LHV) [21]	Not reported	Not reported	Not reported	86.4	86.4	86.4
Steam output (MW_{th})	163	182	200	75	75	75
Availability (%)	92.3	93.0	93.6	93.0	93.0	93.0

Source: GHD analysis and Leigh Fisher (2016) – Table 21

GHD applied typical technical parameters for the design of the steam cycle. As discussed in Section 2, GHD took account of the average through-life performance degradation, which was applied to power output and efficiency.

Low, Medium and High scenarios were applied for performance degradation. The Low figures in Table 3.7 are based on the High degradation assumption resulting in the lowest power output and efficiency, which will ultimately

[20] Net electrical efficiency – The ratio between the net electrical output and the fuel energy input over a given period of time.

[21] CHP efficiency – The ratio between the net electrical output plus the net useful thermal output and the fuel consumed in the production of the electricity and steam.

result in a higher cost of generation (£/kW). The opposite applies to the High scenario, with Low degradation resulting in lower power output and efficiency with a lower cost of generation (£/kW).

For plant availability we have assumed an average through-life figure in our assessment. The average through-life figure accounts for there being longer duration maintenance outages in some years and shorter outages in others.

It should be noted that the performance GHD have estimated cannot be directly compared against the previous study since the basis for both CHP concepts deviate significantly. The previous study assumed much higher process steam pressure and temperature and accounted for operation in both CHP mode and power-only mode. Our process steam assumptions are aligned to the expected end user requirements, and GHD have only considered CHP mode. In our opinion, power-only mode would not be a 'normal' operating condition and would only occur in short-term outage scenarios when the end user was unable to accept steam.

Capital cost

Our assessment of capital costs based on the Phase 1 approach is given in Table 3.8. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These capital cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.2.

Table 3.8: Generation Option 2 – Development and capital costs[22]

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Project development (£/kW)	27.1	52.2	79.7	29.9	67.9	79.6
Capital cost (£/kW)	493	580	667	865	1,018	1,170
Infrastructure (£m)	6.8	13.6	27.1	2.2	4.3	8.6

Source: GHD analysis and Leigh Fisher (2016) – Table 22

Our project development cost represents expenditure by the developer prior to FID and includes pre-licensing and regulatory cost, as per the previous study, as a single line item. Our capital cost estimate is based on a turnkey EPC delivery strategy. The infrastructure costs include fuel gas connection and electrical grid connection works.

A breakdown of the capital costs for this Generation Option based on the Medium cost estimate is provided in Table 3.9 below.

Table 3.9: Generation Option 2 – Capital Cost Breakdown

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Specialised equipment Including: Gas turbine package, steam turbine package, heat recovery boiler, air cooled condensers, CEMS, DCS, transmission and generating voltage equipment.	53.7%	546
Other equipment Including: Pumps, tanks, heat exchangers, emergency generators, medium and low voltage equipment.	4.4%	45
Civil	8.4%	85

[22] As noted, the CHP configuration assumed in the previous study differs significantly from the configuration assumed for this report. These differences mean that the CHP cost estimates from both studies should not be directly compared.

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Including: Site work, excavation and backfill, concrete works and any roads, parking and walkways.		
Mechanical Including: On-site transport and rigging, equipment erection and assembly and piping.	11.4%	116
Electrical Assembly & Wiring Including: Controls, assembly and wiring.	3.2%	33
Buildings & Structures Including: Turbine hall, administrations and control rooms, water treatment system, and a guard house.	7.9%	80
Engineering & Plant set up	11%	113

Source: GHD analysis

The costs we have estimated cannot be fairly compared against the previous study since the basis for both CHP concepts deviate significantly.

Operation and Maintenance cost

Our assessment of fixed and variable costs based on the Phase 1 approach is summarised in Table 3.10. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These post-construction cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.2.

Table 3.10: Generation Option 2 – O&M costs

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	9,970	12,240	14,670	28,850	33,880	38,920
Variable fee (£MWh)	1.22	1.43	1.83	1.58	1.86	2.13
Insurance (% cap/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 8

The O&M costs that we present, which are referenced to MW of capacity or MWh generation, take account of performance degradation. The degraded costs are effectively higher, because of the reduced capacity of the plant, compared to the new and clean condition. Fixed and variable costs are based on in-house LTSA estimates and project experience, and by applying the assumed hours and starts for the option.

3.3. Generation Option 3: OCGT <300 MW

Description

OCGT plants are typically used for peaking power applications as they can be started up relatively quickly to meet increasing electricity demand on the grid system. They are less efficient than CCGT plants as they do not utilise the waste heat from the exhaust gases for additional power generation.

For this generation option, a single ‘F’ class gas turbine was adopted, with the output limited to less than 300 MW in order to fall within the CCR threshold currently applicable in the UK. Being below the CCR threshold means the plant developer would not have to make provisions for CCR, including studies and provision of additional land for future carbon capture equipment.

Key project timings

GHD's assessment of project timings is provided in Table 3.11. Values drawn from the Leigh Fisher study of 2016 are also shown for reference. The project development and construction timings that GHD have proposed are based on recent project experience and are aligned with the previous study.

Table 3.11: Generation Option 3 – Key project timings

Period (Years)	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Project development	1.5	1.8	4.5	1.5	1.8	4.5
Construction	1.5	2.0	2.5	1.5	2.0	2.5
Operation	20	25	35	20	25	30

Source: GHD analysis and Leigh Fisher (2016) – Table 11

The operations period is dictated by the design life of the asset and how the plant has been commercially operated. In GHD's experience, the operational life of an OCGT plant is nominally 25 years but this can be shortened in certain circumstances.

The operational estimates GHD have provided are consistent with the CCGT option. While an OOGT peaking plant would theoretically accrue fewer operating hours than a mid-merit CCGT plant, the number starts/stops could be significantly higher for the OCGT. In our opinion, the assumptions made in the previous report are generally reasonable, although GHD consider an upper limit of 30 years to be more appropriate than 35 years. After 30 years end-of-life refurbishment would be expected as discussed later in this report (Section 4).

Plant performance

GHD used GT Pro to thermodynamically model the OCGT plant. The heat balance diagram for this option is shown in Appendix B.3. The heat balance diagram represents performance in the new and clean condition. Our assessment of the degraded performance is provided in Table 3.12, which summarises both the 1,500 and the 500 operating hour cases. GHD calculate that the net performance parameters are the same under both operating hour cases.

Values drawn from the 2016 Leigh Fisher study are also shown for reference.

Table 3.12: Generation Option 3 – Plant Performance

Parameters	Leigh Fisher (2016) (2,000/500 hrs)			Current Estimate (1,500/500 hrs)		
	Low	Med	High	Low	Med	High
Net power output (MW)	292	299	299	299	299	299
Net efficiency (%, LHV)	38.3	38.7	42.2	38.9	38.9	39.0
Availability (%)	91.4 / 92.9	94.9 / 96.4	96.2 / 97.6	95.0	95.0	95.0

Source: GHD analysis and Leigh Fisher (2016) – Appendix G

A Low, Medium and High scenario was applied for degradation of net power output. The net power output is limited by the CCR capacity threshold, regardless of the gas turbine rating. Since the gas turbine rated output is above 300 MW, the power output degradation is offset by the additional capacity that is available. Hence the degraded net power output is constant through the Low, Medium and High scenarios (for both the 1,500 and the 500 operating hour cases).

A Low, Medium and High scenario was applied for degradation of efficiency. Given the low number of operating hours considered for this option, the relative impact of degradation on efficiency between the Low, Medium and High scenarios is negligible, hence the degraded efficiency is constant in each case.

For plant availability, GHD have assumed an average through-life figure. This figure accounts for there being longer duration maintenance outages in some years and shorter outages in others. The performance that has been estimated is generally aligned with the Leigh Fisher study. This is as expected, given that it is based on the older F class turbine.

Two availability figures presented by Leigh Fisher in 2016, which are both shown in Table 3.12 above. These figures represent its proposed availability based on 2,000 and 500 operating hours respectively. We only present one availability figure because we do not perceive there to be a difference, on average, between a plant operating for 1,500 or 500 hours per year.

Capital cost

GHD's assessment of capital cost based on the Phase 1 approach is given in Table 3.13. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These capital cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.3.

Table 3.13: Generation Option 3 – Development and capital costs

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Project development (£/kW)	17.5	19.9	24.9	8.6	19.7	23.1
Capital cost (£/kW)	283	291	294	307	361	415
Infrastructure (£m)	7.6	15.1	30.2	6.5	12.9	25.8

Source: GHD analysis and Leigh Fisher (2016) – Table 12

GHD would not expect there to be any difference in capital cost for OCGT plant operating for 1,500 hours or 500 hours per year.

Our project development cost represents expenditure by the developer prior to FID and includes pre-licensing and regulatory cost, as per the previous study, as a single line item. The project development costs GHD have estimated are generally aligned with the previous study. However, the Low estimate is notably lower. GHD believe that this is driven by assumed cost of land, which is included in this study in development costs (see Appendix A).

The capital cost estimate is based on a turnkey EPC[23] delivery strategy. A breakdown of these costs for this Generation Option based on the Medium cost estimate is provided in Table 3.14 below.

Table 3.14: Generation Option 3 – Capital Cost Breakdown

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Specialised equipment Including: Gas turbine package, steam turbine package, heat recovery boiler, air cooled condensers, CEMS, DCS, transmission and generating voltage equipment.	69.4%	251
Other equipment	2.5%	9

[23] An Engineering, Procurement, Construction (EPC) delivery strategy is where a buyer hires a contractor to design, plan, and execute a project from start to finish.

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Including: Pumps, tanks, heat exchangers, emergency generators, medium and low voltage equipment.		
Civil Including: Site work, excavation and backfill, concrete works and any roads, parking and walkways.	9.0%	32
Mechanical Including: On-site transport and rigging, equipment erection and assembly and piping.	6.9%	25
Electrical Assembly & Wiring Including: Controls, assembly and wiring.	2.6%	9
Buildings & Structures Including: Turbine hall, administrations and control rooms, water treatment system, and a guard house.	2.2%	8
Engineering & Plant set up	7.4%	27

Source: GHD analysis

Infrastructure costs are the cost of gas and electrical power connections. Since these are site specific it is difficult to assess these costs. For consistency with previous reports, we have used costs in the previous reports as a reference and adjusted them for plant capacity, gas consumption and price indexing.

Operation and Maintenance cost

GHD's assessment of fixed and variable costs based on the Phase 1 approach are summarised in the tables below. The costs are summarised according to the assumed number of operating hours per year. Table 3.15 relates to 500 hours and Table 3.16 relates to 1,500 hours. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These post-construction cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.3.

Table 3.15: Generation Option 3 – Operation and Maintenance Costs (500 hours)

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	5,066	6,347	7,607	9,770	11,490	13,210
Variable fee (£/MWh)	0.95	1.23	1.42	4.05	4.76	5.47
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 13

Table 3.16: Generation Option 3 – Operation and Maintenance Costs (1,500 hours)

Parameters	Leigh Fisher (2016) (2,000 hrs) 2014 prices			Current Estimate (1,500 hrs) 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	7,600	9,521	11,411	9,710	11,423	13,136
Variable fee (£/MWh)	0.95	1.23	1.42	3.71	4.36	5.01
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 13

The O&M costs that are presented, which are referenced to the MW and MWh generation, take account of performance degradation. The degraded costs are effectively higher, because of the reduced capacity of the plant, compared to the new and clean condition.

Fixed and variable costs are based on in-house long-term service agreement (LTSA) estimates and project experience, and applying the assumed operating hours and starts for each scenario.

The estimated variable O&M cost is lower for 1,500 operating hours, than for 500 hours, because of the assumed number of starts. For the 500-hour scenario, more starts have been assumed, which disproportionately increases the variable O&M cost despite the lower number of operating hours.

3.4. Generation Option 4: OCGT >300 MW

Description

This generation option is broadly the same as Generation Option 3. However, this generation option is intended to represent a gas turbine peaking plant that might be constructed under the Government's new Decarbonisation Readiness requirements (i.e. with the 300 MW threshold removed).

In removing the CCR threshold, the power output is increased by installing an additional gas turbine. Two 'F' class gas turbines were adopted for this option.

Key project timings

GHD's assessment of project timings is provided in Table 3.17. drawn from the Leigh Fisher study of 2016 are also shown for reference.

Table 3.17: Generation Option 4 – project timings

Period (Years)	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Project development	1.5	1.8	4.5	1.5	1.8	4.5
Construction	1.5	2.0	2.5	1.6	2.1	2.6
Operation	20	25	35	20	25	30

Source: GHD analysis and Leigh Fisher (2016) – Table 11

The project development and construction timings are identical to the timings set out for Generation Option 3 (shown in Table 3.11). However, the estimated construction timings are slightly longer than for Generation Option 3, to accommodate the staggered manufacturing, delivery, installation and commissioning of the second gas turbine unit (and associated equipment).

Plant performance

GHD used GT Pro to thermodynamically model this OCGT plant. The heat balance diagram for this option is shown in Appendix B.4. The heat balance diagram represents performance in the new and clean condition. Our assessment of the degraded performance for this Generation Option is provided in Table 3.18, which summarises both the 1,500 and the 500 operating hour cases. Values drawn from the 2016 Leigh Fisher study are also shown for reference.

Table 3.18: Generation Option 4 – plant performance

Parameters	Leigh Fisher (2016) (2,000/500 hrs)			Current Estimate (1,500/500 hrs)		
	Low	Med	High	Low	Med	High
Net power output (MW)	602	625	664	753	755	755

Net efficiency (LHV)	38.3	39.2	39.9	40.2	40.3	40.3
Availability (%)	91.4 / 92.9	94.9 / 96.4	96.2 / 97.7	95.0	95.0	95.0

Source: GHD analysis and Leigh Fisher (2016)

A Low, Medium and High scenario was applied for degradation of net power output and efficiency. The Low figures in Table 3.18 are based on the High degradation assumption resulting in the lowest power output and efficiency, which will ultimately result in a higher cost of generation (£/kW). The opposite applies to the High scenario, with Low degradation resulting in relatively higher power output and efficiency with a lower cost of generation (£/kW). The limited number of operating hours, and hence average degradation, has limited influence on plant performance. Performance degradation will impact this option (differently to the 299 MW plant) because these units will be operating at full load and hence there is no 'reserve' capacity available.

For plant availability we have assumed an average through-life figure in our assessment. The average through-life figure accounts for there being longer duration maintenance outages in some years and shorter outages in others.

There were two availability figures presented by Leigh Fisher, which are shown in Table 3.18 above. These figures represent its proposed availability based on 2,000 and 500 operating hours respectively. We only present one availability figure because we don't perceive there to be a significant difference, on average, between a plant operating for 1,500 or 500 hours per year.

Capital cost

Our assessment of capital costs based on the Phase 1 approach is given in Table 3.19. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These capital cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.3.

Table 3.19: Generation Option 4 – Development and capital costs

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Project development (£/kW)	17.5	19.9	24.9	8.7	18.0	21.1
Capital cost (£/kW)	283	291	294	269	316	363
Infrastructure (£m)	7.6	15.1	30.2	9.5	18.9	37.8

Source: GHD analysis and Leigh Fisher (2016) – Table 12

As with Generation Option 3, GHD would not expect there to be any difference in capital cost for OCGT plant operating for 1,500 hours or 500 hours per year.

The project development costs GHD have estimated are generally aligned with the previous study, however, the Low estimate is notably lower and GHD believe that this is driven by assumed cost of land (which is covered in Appendix A).

Our capital cost estimate is based on a turnkey EPC delivery strategy. A breakdown of these costs for this Generation Option based on the Medium cost estimate is provided in Table 3.20 below.

Table 3.20: Generation Option 4 – Capital Cost Breakdown

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Specialised equipment	72.0%	227

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Including: Gas turbine package, steam turbine package, heat recovery boiler, air cooled condensers, CEMS, DCS, transmission and generating voltage equipment.		
Other equipment Including: Pumps, tanks, heat exchangers, emergency generators, medium and low voltage equipment.	2.6%	8
Civil Including: Site work, excavation and backfill, concrete works and any roads, parking and walkways.	8.6%	27
Mechanical Including: On-site transport and rigging, equipment erection and assembly and piping.	7.2%	23
Electrical Assembly & Wiring Including: Controls, assembly and wiring.	2.9%	9
Buildings & Structures Including: Turbine hall, administrations and control rooms, water treatment system, and a guard house.	1.2%	4
Engineering & Plant set up	5.5%	18

Source: GHD analysis

Infrastructure costs are the cost of gas and electrical power connections. Since these are site specific it is difficult to assess these costs. For consistency with previous reports, we have used costs in the previous reports as a reference and adjusted them for plant capacity, gas consumption and price indexing.

Operation and Maintenance cost

GHD's assessment of fixed and variable costs based on the Phase 1 approach are summarised in the tables below. The costs are summarised according to the assumed number of operating hours per year. Table 3.21 relates to 500 hours and Table 3.22 relates to 1,500 hours. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These post-construction cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.3.

Table 3.21: Generation Option 4 – O&M costs (500 hours)

Parameters	Leigh Fisher (2016) (500 hrs) 2014 prices			Current Estimate (500 hrs) 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	3,643	4,564	5,470	7,520	8,830	10,150
Variable fee (£/MWh)	0.68	0.88	1.02	4.1	4.9	5.6
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 13

Table 3.22: Generation Option 4 – O&M costs (1,500 hours)

Parameters	Leigh Fisher (2016) (2,000 hrs) 2014 prices			Current Estimate (1,500 hrs) 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	5,465	6,846	8,205	7,520	8,830	10,150

Variable fee (£/MWh)	0.68	0.88	1.02	3.8	4.5	5.2
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 13

Fixed and variable costs are based on in-house long-term service agreement estimates and project experience, and by applying the assumed operating hours and starts for each scenario.

The estimated variable O&M cost is lower for 1,500 operating hours, than for 500 hours, because of the assumed number of starts. For the 500-hour scenario, more starts have been assumed, which disproportionately increases the variable O&M cost despite the lower number of operating hours.

3.5. Generation Option 5: Reciprocating engines

Description

Gas-fired reciprocating engine power plants are utilised extensively in the UK to provide peaking power. The capacity of these plants is typically of the order of 20 MW but can vary. Gas engine plants can start up rapidly to meet increasing electricity demand on the grid system and are more fuel efficient than OCGT plant.

Gas engine sites are typically unmanned for much of the time and are usually dispatched remotely by a trader (or 'optimiser') according to the prevailing electricity prices. Operations staff attend site periodically to undertake routine maintenance work and as required to resolve breakdowns.

In our experience, such projects utilise containerised gas engines with a rated output between 2.0 MW and 4.5 MW. For the purpose of this study, six 3.45 MW gas engine were selected to achieve the target 20 MW capacity.

Key project timings

Our assessment of project timings is provided given in Table 3.23 below. Values from the Leigh Fisher study of 2016 are included for reference.

The project timings, particularly the project development and construction durations, are independent of the assumed operating hours.

In our experience, the project development timeline is influenced by the planning application and associated requirements together with the process to secure and progress with a connection offer. GHD consider the previous estimates to be reasonable and are unchanged.

In GHD's opinion the construction timings presented in the previous study are optimistic. Our estimates for construction time are based on recent project experience in the UK.

In GHD's experience, gas engine projects operating within the Capacity Market are typically specified with a design life of 25 years and it is reasonable to expect that the engines themselves should have an economic life of around 100,000 hours. Many such reciprocating engine projects acquire 15-year contracts in the Capacity Market. It is therefore deemed reasonable to assume an equivalent operating period as a minimum and nominal operating life of 25 years. Based on GHD's experience in the refurbished engine market, as the annual operating hours are relatively few, there is potential scope for continued operation beyond the 25 years subject to the condition of the balance of plant; however, this is difficult to quantify.

Table 3.23: Generation Option 5 – project timings

Period (Years)	Leigh Fisher (2016)			Current Estimate		
	Low	Med	High	Low	Med	High
Project development	1.0	2.0	3.0	1.0	2.0	3.0
Construction	0.3	0.5	0.7	0.4	1.0	1.3

Operation	10.0	15.0	17.0	15	25	>25

Source: GHD analysis and Leigh Fisher (2016) – Table 16

Plant performance

GHD used GT Pro to thermodynamically model the engine plant. The heat balance diagram for this option is shown in Appendix B.5. The heat balance diagram represents performance in the new and clean condition.

We took account of the average through-life efficiency degradation and average through-life availability. The average through-life figure accounts for there being longer duration maintenance outages in some years and shorter outages in others. Our assessment of the degraded performance for this generation option is provided in Table 3.24, which summarises both the 1,500 and the 500 operating hour cases. Values drawn from the 2016 Leigh Fisher study are also shown for reference.

Table 3.24: Generation Option 5 – plant performance

Parameters	Leigh Fisher (2016) (2,000/500hrs)			Current Estimate (1,500/500hrs)		
	Low	Med	High	Low	Med	High
Net power output (MW)	18.0	20.0	22.0	20	20	20
Net efficiency (%, LHV)	35.0	36.0	37.0	44.6	44.6	44.6
Availability (%)	92.2 / 92.6	94.3 / 94.7	95.7 / 97.0	95.0	95.0	95.0

Source: GHD analysis and Leigh Fisher (2016) – Table 17

The plant efficiency that GHD have estimated is notably higher than that reported in the previous study. Leigh Fisher previously assumed multiple 1.0 MW – 2.0 MW engines whereas GHD have assumed a smaller number of engines with a higher individual capacity, which are more efficient.

The previous study proposed Low, Medium and High scenarios. The basis for these scenarios is not known. In our opinion there should be no real difference in performance between a plant operating for 500 hours or 1,500 hours per year. Hence, GHD have applied consistent performance parameters.

Capital cost

Our assessment of capital costs based on the Phase 1 approach is given in Table 3.25. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These capital cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.4.

Table 3.25: Generation Option 5 – capital and development costs

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate		
	Low	Med	High	Low	Med	High
Project development (£/kW)	10.1	13.0	17.5	12.7	29.5	34.6
Capital cost (£/kW)	276	300	324	450	529	609
Infrastructure (£m)	0.7	3.4	10.3	1.1	2.1	4.2

Source: GHD analysis and Leigh Fisher (2016) – Table 18

No differences in the capital costs for an engine plant operating for 1,500 hours or 500 hours per year is assumed.

The project development cost represents expenditure by the developer prior to FID and includes pre-licensing and regulatory cost, as per the previous study, as a single line item. Our capital cost estimate is based on a turnkey EPC delivery strategy.

Our capital cost estimate is based on a turnkey EPC delivery strategy. A breakdown of these costs for this Generation Option based on the Medium cost estimate is provided in Table 3.26 below.

Table 3.26: Generation Option 4 – Capital Cost Breakdown

Item	% of Capex	Cost (£/kW) – Medium Value 2024 Prices
Specialised equipment Including: Gas turbine package, steam turbine package, heat recovery boiler, air cooled condensers, CEMS, DCS, transmission and generating voltage equipment.	16.9%	88
Other equipment Including: Pumps, tanks, heat exchangers, emergency generators, medium and low voltage equipment.	6.2%	33
Civil Including: Site work, excavation and backfill, concrete works and any roads, parking and walkways.	18.1%	96
Mechanical Including: On-site transport and rigging, equipment erection and assembly and piping.	21.5%	114
Electrical Assembly & Wiring Including: Controls, assembly and wiring.	8.9%	47
Buildings & Structures Including: Turbine hall, administrations and control rooms, water treatment system, and a guard house.	18.2%	96
Engineering & Plant set up	10.2%	55

Source: GHD analysis

The infrastructure costs include for the fuel gas connection and electrical grid connection works. The costs are based on recent project experience in the UK.

Operation and Maintenance cost

GHD's assessment of fixed and variable costs based on the Phase 1 approach are summarised in the tables below. The costs are summarised according to the assumed number of operating hours per year. Table 3.27 relates to 500 hours and Table 3.28 relates to 1500 hours. Values drawn from the Leigh Fisher 2016 report are also shown for reference. The background information and basis for the estimates is presented in Appendix C. These post-construction cost estimates are compared against evidence gathered from stakeholders in Phase 2 in Section 5.1.4.

Table 3.27: Generation Option 5 – O&M costs (500 hours)

Parameters	Leigh Fisher (2016) 2014 prices			Current Estimate 2024 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	8,000	10,000	12,000	12,400	14,630	16,820
Variable fee (£/MWh)	0.05	0.07	0.08	5.72	6.73	7.74
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 19

Table 3.28: Generation Option 5 – O&M costs (1,500 hours)

Parameters	Leigh Fisher (2016) (2,000 hrs) 2014 prices			Current Estimate (1,500 hrs)		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	8,000	10,000	12,000	12,400	14,630	16,820
Variable fee (£/MWh)	0.05	0.07	0.08	3.45	4.06	4.67
Insurance (% capex/yr)	0.3	0.4	0.5	0.3	0.4	0.5

Source: GHD analysis and Leigh Fisher (2016) – Table 19

The O&M costs that we present, which are referenced to the MW and MWh generation, take account of performance degradation. The degraded costs are effectively higher, because of the reduced capacity of the plant, compared to the new and clean condition.

Fixed and variable costs are based on in-house long-term service agreement estimates and project experience, and by applying the assumed operating hours and starts for each scenario.

The estimated variable O&M cost is lower for 1,500 operating hours, than for 500 hours, because of the assumed number of starts. Variable maintenance cost for engines is based on operating hours only so the number of starts has no effect on these costs. The costs are based on typical VOM and FOM rates for plant of this type and capacity. These rates only include for core engine and generator costs and do not include for other fixed costs such as staffing (offsite support/admin, security, etc) and general plant site maintenance. The small capacity of the plant greatly increases the specific cost of these other items.

4. PHASE 1: COST OF END-OF-LIFE REFURBISHMENT

4.1. Overview

In addition to the 'new build' generation options, DESNZ requested that refurbishment and repowering of an unabated CCGT power plant be considered as part of Phase 1. The size of the plant assumed here is the same as in Generation Option 1 (1,700 MW). Table 4.1 summarises the Refurbishment and Repowering Options that are considered in this report.

Table 4.1: Refurbishment & Repowering Options

Refurbishment & Repowering Option	Technology	Scenario	Description
1A	CCGT H Class	Standard maintenance benchmark.	Cost benchmark for typical through life maintenance of major CCGT equipment items.
1B	CCGT H Class	End of life extension.	Extending the life of the CCGT for 5 years by replacing and refurbishing key component of the major equipment items.
1C	CCGT H Class	Repowering at end of life.	Extending the life of the project site by 10-25 years by replacement of all major equipment items.

Source: Discussions with DESNZ

The scope of these study options was discussed and agreed with DESNZ. The approach and methodology in estimating costs associated with each option are explained in the following sections.

Option 1A: Benchmark

An average annual CCGT maintenance cost was estimated to provide a benchmark for comparison against the refurbishment costs estimates.

The benchmark was based on a single CCGT maintenance cycle. The costs are dominated by the maintenance of the gas turbines.

For the gas turbines, this which would include multiple minor inspections and one hot gas path inspection leading up to and including the first major outage (as described in Section 2.6.5). There would not be any significant maintenance expected for the HRSG, and only a minor inspection of the steam turbine during this cycle. Gas turbine manufacturers have different definitions for outages and maintenance regimes, but generally these comprise regular minor inspections including the combustors which might require some replacement of minor combustor parts (combustor liners, fuel nozzles, etc); hot gas path inspections which concentrates mainly on the combustors and the turbine section requiring scheduled repair and/or replacement of parts such as blades and vanes; and major inspections which examine the entire gas turbine including the compressor section and will require further repair/replacement.

An average of all maintenance outage costs (excluding foregone revenues) was calculated from the maintenance cycle.

Option 1B: Life Extension

Estimating costs of extending the life of power plant beyond the original design intent (nominally 25 years) is very difficult. It is dependent on the general condition of the equipment and more complex factors, such as the creep life of high temperature components.

Prior to making an investment decision, a detailed inspection would be carried out together with an assessment of the operating regime to date and the expected operating requirements going forward to establish the cost of the works required in order to realise the additional life.

In extending the life of a CCGT plant by 5 years, it is reasonable to expect that replacement and refurbishment/repairs works would be required on the gas turbines (e.g. compressor and turbine blade/vane replacement), the HRSG's (e.g. tube replacement and leak repairs), the steam turbine (e.g. blade replacement) and the wider balance of plant equipment (e.g. pump replacement).

GHD have estimated the cost of life extension on the basis of quotations from within the previous 5 years for refurbishment of other CCGT power plants and accordingly adjusted the costs to account for differences in technology, equipment configuration and power capacity, in comparison with Option 1, and escalated the price to 2024 values.

Option 1C: Repowering

In extending the life of power plant by 10-25 years, beyond the original design intent, it has been assumed that all 'above ground' equipment would be dismantled, removed from site (having reached the end of the economic life) and replaced with new.

For the purposes of this study, it is reasonable to assume that the civil works (i.e. the foundations) would have an expected life of 50 years, although in reality, there would need to be extensive surveys of the civil works at the time of refurbishment to establish remnant life and whether the existing works are suitable for reuse.

For continued use of the existing civil works, it would be necessary to implement a like-for-like replacement of CCGT power plant equipment. Foundations are basically designed according to static and dynamic loading that would be imposed. Hence, it would not be feasible to remove a gas turbine (or any other major equipment item) of a particular type/size and replace it with a significantly larger unit, for example.

As such, this option is potentially prohibitive in that the equipment available on the market today may be replaced by more advanced machines by the time repowering is undertaken. There is also the potential for other regulatory influences that may prohibit this approach, but this is beyond the scope of this study.

4.2. Refurbishment Cost Summary

GHD have estimated costs for each of the refurbishment options and these are summarised in Table 4.2 below.

Table 4.2: Refurbishment Cost Summary

Option	Scenario	Summary of Works	Estimated Cost (2024 values)	
			£m	£/kW
1A	Standard maintenance benchmark.	Typical through life maintenance of major CCGT equipment items.	50	31
1B	End of life extension for 5 years.	Replacement and refurbishment of key components of the major equipment items and balance of plant.	140	81
1C	Repowering at end of life. For a further 10-25 years' service.	Replacement of all major equipment items and balance of plant.	930	545

Source: GHD analysis

5. PHASE 2: STAKEHOLDER ENGAGEMENT

This section sets out Phase 2 of our study where we engaged with prospective developers of unabated gas generation projects in GB. The purpose of this Phase was to supplement and build on the bottom-up analysis developed as part of Phase 1. For example, to account for some of the cyclical factors that may impact on the cost of real-world projects which were noted in Section 2.1.

This phase of work was delivered through two core parts:

- **Stakeholder questionnaire**: We created a questionnaire to collect stakeholder insights on the cost of developing new unabated gas projects in GB and the costs associated with extending the lifespan of existing units. Respondents were asked to provide cost information on real-world projects which they were directly involved across various stages, including the planning, developing, operating, or refurbishing of gas generation projects. Respondents were asked to provide separate responses for CCGT, OCGT, CHP, and reciprocating engine projects. A copy of this questionnaire is provided in Appendix D.
- **Follow-up interviews**: We held a series of follow-up interviews with those stakeholders that responded to our questionnaire. The purpose of these interviews was to clarify, verify, and challenge the responses where necessary, particularly in cases where reported costs differed from the estimates developed in Phase 1 by GHD.

This questionnaire was distributed to 25 organisations in February 2025 to which just five responses were received, as illustrated in Table 5.1 below. Two responses included information on CCGT and OCGT projects, while four responses provided information on reciprocating engine projects and one respondent provided some information on a CHP project. All organisations that provided a response were also invited for an interview in March 2025. Four of those developers accepted this invitation.

Table 5.1: Summary of questionnaire responses received as part of Phase 2

Respondent	Interview held?	Information provided on each generation option?			
Response 1	Yes	Yes	Yes	Yes	Yes
Response 2	Yes	Yes	Yes	No	No
Response 3	Yes	No	No	No	Yes
Response 4	Yes	No	No	No	Yes
Response 5	No	No	No	No	Yes

Source: CEPA

The limited engagement in this process constrains our ability to draw definitive conclusions from this phase of work. Individual developers and generation projects may experience costs that differ from a typical project for various reasons, making it challenging to derive a clear conclusion on costs from a small engagement sample. Additionally, we note that the value of insights from this stakeholder engagement process depends on the quality and reliability of the data provided. While the questionnaire and interview processes were used to verify the quality of information provided, we note that developers may have an underlying incentive to report higher or lower costs to influence broader DESNZ policy development.

Box 1: Confidentiality

All questionnaire responses and follow-up interviews were conducted on a confidential basis. The information gathered through this process was not directly shared with DESNZ or with any other stakeholder. The following commentary therefore does not make reference to any specific project or provide information that would allow a reader to identify which organisations have participated in this process.

5.1. Summary of Responses

The following sections summarises the responses that have been received across each gas generation technology that is in scope for this report.

5.1.1. CCGTs

This section summarises the information that we have gathered in this phase on the costs of developing new CCGT generation.

Reference Projects

As noted above, we received two responses regarding the cost of developing new CCGT projects in Great Britain. One response included cost information for one prospective H-Class CCGT plant with a lower heating value (LHV) efficiency of 62% and an annual average load factor of 20–30%. The respondent indicated that these costs were based on a recent engagement with their supply chain and original equipment manufacturers (OEMs) between 18 and 24 months prior to the Phase 2 questionnaire being provided. The other respondent provided a cost estimate for a notional new CCGT plant but did not specify its assumed technical operating characteristics.

Follow-up interviews were conducted with both respondents.

Pre-Operational Costs

Both respondents provided information on pre-operational (i.e., development and construction) costs. This is summarised below.

- The respondents suggested that pre-construction costs were in the range of £10/kW to £25/kW, excluding contingency and any land acquisition costs. One respondent suggested that the contingency budget for the pre-construction phase could amount to an additional £3/kW to £7/kW.
- The respondents suggested that total construction costs were in the range of £800/kW to £1,200/kW, excluding contingency. All respondents suggested that the continency budget for the construction phase could amount to an additional £200/kW to £300/kW. These estimates include the cost of connection to the gas grid and electricity network.
- Both respondents indicated that construction costs have risen significantly in recent years. According to the respondents, these cost increases are primarily driven by international supply chain disruptions rather than domestic factors in Great Britain. They highlighted the impact of the COVID-19 pandemic, which forced companies that manufacture gas turbines and engines to scale back their operations. The respondents indicated that these manufacturers may now be attempting to recoup losses from that period by charging higher prices today. Additionally, they noted that the surge in global demand for gas turbines—particularly from markets such as Romania and the Middle East—has further contributed to rising costs. While the respondents suggested that these cost pressures were likely to continue, no estimated timeline or end date for when these cyclical cost pressures may subside was provided.
- One respondent highlighted the rising costs of connecting to both the gas and electricity grids. They estimated that developing a new gas network connection could reach £20 million per km, while connecting to the electricity grid could reach £15 million per km. The same respondent also emphasised the impact of connection delays, particularly for electricity grid connections, which they said can create significant uncertainty and costs for developers. One responded noted that the cost of electricity grid connection increased by over 300% over the course of a few years, from approximately £3 million to £10 million.

We note that these reported costs are materially higher than the estimates developed by GHD in Phase 1. The range of construction costs, including connection costs, is around 40% to 110% higher than the High estimates from Phase 1. Similarly, the range of development costs, excluding land acquisition, shared by respondents is around 90% and 365% higher than the High estimates developed in Phase 1.

A comparison of these estimates is illustrated in Table 5.2 below.

Table 5.2: Comparison of Pre-Operational Costs - CCGTs

	Phase 1 Estimates	Phase 2: Response From Stakeholders
Capital Costs		
Capital Costs (excl. connections)	£510/kW - £691/kW	n/a
Capital Costs (incl. connections)	£517/kW - £719/kW	£1,000/kW - £1,500/kW
Development Costs		
Development Costs (incl. Land)	£7.2/kW - £19.6/kW	n/a
Development Costs (excl. land)	£5.1/kW - £6.9/kW	£13/kW - £32/kW

Source: CEPA analysis

The estimates provided by the two respondents indicate that the cost of developing a new CCGT plant in GB has risen significantly in recent years, and that they are significantly above the bottom-up estimates developed in Phase 1. Phase 2 evidence suggests that costs have risen primarily due to supply chain pressures, and that supply chains remain tight. We note that this position is consistent with external evidence on the growth in global orders for new gas-fired generation capacity.

Nevertheless, as noted in Section 2.1, the power generation equipment market tends to be cyclical, and the cost of power generation projects at any point in time is the function of available manufacturer discounts or premiums, supply and demand levels, and site-specific characteristics. The evidence presented by the two respondents suggests that the market has tightened and that costs are currently[24] at a level that is above even the 'High' bottom-up estimate that were developed in Phase 1.

We note that the survey has produced only two data points. Consequently, it may not be appropriate to draw firm conclusions from this evidence. Nevertheless, the evidence collected indicates a large gap between Phase 1 and Phase 2 estimates. Phase 2 findings suggest that the current cost of developing a new CCGT plant is likely higher than even the high estimate developed by GHD in Phase 1. Therefore, it may be appropriate to assume higher generation costs for projects to be developed in the near future than the Phase 1 estimates. We provide further conclusions that draws together the outcome of Phase 1 and Phase 2 in Section 6.

Post-Construction Costs

Only one respondent provided information on post-construction costs. This is summarised below.

- The fixed and variable O&M costs included in this response fall within the range developed by GHD as part of Phase 1. Their estimate of ongoing insurance costs also falls in the range developed by GHD. These estimates are based on expected average costs over a 15-year time horizon. The respondent noted that these costs are highly dependent on plant performance (i.e., outage frequency) and that operational costs generally increase with or above outturn CPI inflation.

- One respondent noted that new-build projects have a financial life of around 25 years. Mid-life investment can extend the life of these assets by around 10 years. This respondent noted that the cost of this extension could range between £90 million and £150 million. They noted that this estimate is highly uncertain however and influenced by the way that the asset was operated over its existing lifetime and the general site conditions.

[24] While the respondents to our survey did not provide information on to what extent and when supply chain pressures might ease, we note that a potential easing of supply chain pressures could result in a fall of new CCGT plant costs in the future.

- The same respondent suggested that the gross cost of decommissioning a CCGT plant may be around 10% below the value that can be gained from the sale of scrap parts. However, they noted that assuming a zero decommissioning cost is a reasonable ex-ante approach.
- No information was received from either organisation on other post-construction costs for CCGTs, such as property tax, use of service/system charges, or other relevant expenses.

Overall, the post-construction cost estimates provided by this one respondent fall within the range established by GHD in Phase 1. As such, there is no evidence from this engagement to adjust the cost range developed as part of the bottom-up analysis delivered in Phase 1.

Other

We note other considerations that were raised by the two respondents regarding the development of new unabated gas CCGTs:

- One respondent suggested that it may not be technically feasible for new H-Class CCGTs to be developed under a single-shaft configuration. They indicated that a multi-shaft approach (such as the one assumed by GHD in Phase 1) is most compatible with H-Class units.
- One respondent noted that Government policy will be key in determining whether new unabated CCGT projects are developed. They noted that other European markets are proactively pursuing the connection of new gas projects and that arrangements in GB will need to be competitive in order to secure investment.

5.1.2. CHPs

One responded provided some information on some post-construction cost categories for a CHP plant. They indicated that the cost of gas and electricity network charges were each between £5 and £6 million per annum and that property and business rates are between £1 and £2 million per annum. No other information was provided for this generation archetype.

5.1.3. OCGTs

Two respondents provided information on OCGT projects. One project had a F-class turbine in a single-shaft configuration, with LVH efficiency of 41% and operational life of 25 years. The other respondent provided cost information based on a notional project, but did not provide information on technical characteristics.

Pre-Operational Costs

Both respondents provided information on pre-construction and construction costs. These are summarised below.

- Pre-construction costs were estimated to be between £10/kW and £70/kW, excluding contingency and land acquisition costs. One respondent indicated that they would add 10%-20% on top of the cost estimate as contingency.
- One respondent expected pre-construction costs to remain at the current high levels or to increase due to the demand for new projects and the limited supply chain.
- Construction costs were estimated to be between £450/kW and £1,450/kW, excluding contingency. The upper bound is based on an estimate including gas and electricity connections, while the lower bound estimate only includes gas connection cost and is based on a site in close proximity to connections.
- One respondent indicated that the cost of equipment accounts for 30% of total construction costs.

Table 5.3 below summarises the responses on development and construction costs for OCGTs.

Table 5.3: Comparison of Pre-Operational Costs - OCGT

	Phase 1 Estimates	Phase 2: Response From Stakeholders
Capital Costs		
Capital Costs (excl. connections)	£269/kW - £363/kW	n/a
Capital Costs (incl. connections)	£281/kW - £412/kW	£450/kW - £1,450/kW
Development Costs		
Development Costs (incl. Land)	£8.7/kW - £21.1/kW	n/a
Development Costs (excl. land)	£6.7/kW - £9.1/kW	£10/kW - £70/kW

Source: CEPA analysis

The estimates provided by both respondents indicate that the costs of developing OCGT projects have risen above the bottom-up estimates developed in Phase 1. This is the case for both development and construction costs.

The range of costs implied by the evidence provided by both responses is however highly significant. Construction costs range from around 10% to 250% higher than the High estimates from Phase 1. This range generates a significant degree of uncertainty around the outcome of this Phase, in particular, as the organisation which provided us with the higher cost estimate was unable to provide us with much elaboration to explain the scale of their costs.

Nevertheless, the evidence collected indicates that the pre-construction costs for new OCGT plants are above the High estimates developed in Phase 1. Based on discussions with the respondents, the factors driving the increase in costs are similar to those for CCGTs. We provide further conclusions that draws together the outcome of Phase 1 and Phase 2 in Section 6.

Post-Construction Costs

One respondent provided information on O&M costs, electricity network and gas charges, taxes and decommissioning costs. No information was provided on refurbishment costs.

- On O&M costs, the respondent provided a variable cost that was within the range estimated by GHD (both operating hour options) and a significantly lower estimate of fixed costs. However, the site in question is remotely operated and as such, staffing costs are lower.
- The respondent indicated that the expected annual cost of Transmission Network Use of Service (TNUoS) charges and gas transportation charges in late 2020s are approximately £0.7m and £0.02m, respectively. This respondent also expected annual business rates and taxes to come to around £0.4m each.
- On decommissioning costs, the respondent noted that the value from the sale of scrap parts covers around 25% of the total cost of decommissioning. The respondent expected decommissioning to take two years to complete.

Based on this limited set of information, we do not think that there is any evidence to adjust the cost range developed by GHD as part of the bottom-up analysis delivered in Phase 1.

Other

The respondents also provided information on their future expectations for OCGT projects.

- One respondent expected future OCGTs to use F-Class technology with plant sizes of 300 MW. The other respondent expected smaller sized plants, i.e., 20-100 MW. In terms of the number of future projects, this respondent expected that there will be less than ten new OCGT projects by 2040. The respondent perceived that policy was focused on extending the lives of older assets rather than on constructing new decarbonisation ready plants.

- One respondent noted, in the context of discussing reciprocating engines, that they were not expecting many OCGT plants to be developed due to their higher development cost and lower efficiency rates.

5.1.4. Reciprocating Engines

Reference Projects

Four respondents provided information on project costs for reciprocating engines based on planned and operating plants. All plants had high LVH efficiency, between 43% and 47%, but differed in (expected) operational profile. Annual average operating hours varied from less than 1000 hours to 1750 hours, while expected starts in a year varied from 150 to 600. Operational life for the plants was expected to be 20-25 years, with one respondent noting that operational life may be lower due to general regulatory uncertainty around the future role of unabated gas engines.

Pre-Operational Costs

Three respondents provided information on pre-construction costs, while all respondents provided information on construction costs.

- Pre-construction costs were estimated to be approximately £20-£25/kW, excluding land costs and contingency. These estimates are on the lower end of the spectrum, due to site- and project-specific factors bringing costs down. Respondents considered that the increase in pre-construction costs has been influenced by permitting and connection costs, cost increases from delays in timelines, as well as third-party costs (consultancy) due to high demand.

- Construction costs were in the range of £550-£750/kW, excluding contingency. The respondents indicated that these costs were based on projects with favourable location with existing grid and gas connections or nearby connections. For any site with material spend on connections, the upper bound would be expected to be greater. A contingency was typically added on the construction cost estimate, ranging from less than a million to a few millions. Respondents indicated that the cost of equipment accounted for a large share of construction costs, from 40% to 50%. In Phase 1 estimates, specialised equipment and other equipment were estimated to account for 16.9% and 6.2% of total capital costs.

- Similarly to CCGTs, the three respondents commented on the current supply chain pressure influencing construction costs. The market for reciprocating engines is global with high demand elsewhere, e.g., the Middle East, driving costs up in GB. One respondent estimated that construction costs have been increasing 12% a year between 2021 and 2024/25 based on actual project costs, partly attributable to global demand. The respondent also noted that given the high demand, equipment manufacturers can pick which projects to supply. Equipment manufacturers might focus on more certain investments elsewhere. Another respondent noted that component prices increased sharply during the last few years due to global events but have since returned to close to 2021 prices.

- In addition to the constrained supply chain, respondents mentioned other factors that have contributed to increasing costs. These include a spike in the cost of civil contracts (e.g., steel, concrete) and equipment manufacturers' need to recoup costs associated with research into the next generation of assets. One respondent also noted the lack of workforce in the UK, with large infrastructure projects in other sectors, e.g., transport, increasing demand and many European companies having reduced their presence. It was estimated that the cost of developing unabated gas projects in GB are at or above international costs.

Table 5.4 below summarises the estimates for pre-construction and construction costs from Phase 1 of this study and those received from respondents.

Table 5.4: Pre-Operational Costs – Reciprocating engines

	Phase 1 Estimates	Phase 2: Response From Stakeholders
Capital Costs		
Capital Costs (excl. connections)	£450/kW - £609/kW	n/a
Capital Costs (incl. connections)	£502/kW - £818/kW	£550-£750/kW*
Development Costs		
Development Costs (incl. land)	£12.7/kW - £34.6/kW	n/a
Development Costs (excl. land)	£ 8.9/kW - 12.2£/kW	£20/kW - £25/kW

Source: CEPA analysis

*Note: *While connection costs are included in the estimated received from stakeholders, the connection distances for the projects on which costs are based were minimal, e.g., a few hundred meters to a kilometre. Phase 1 estimates for reciprocating engine projects assume a 5-kilometre connection distance.*

The estimates on construction costs for reciprocating engine plants received from respondents align with those developed in Phase 1, with the caveat that the Phase 1 estimates assume a greater connection distance. Respondents noted that connection costs are material, where the site does not have existing or nearby connections. The responses received suggest that development costs may be higher than the Phase 1 estimates, however, the number of data points on development costs was more limited than construction costs, and as such, the development costs should be interpreted with caution.

Nevertheless, taken as a whole (capital plus development costs) we do not think that the Phase 2 evidence suggests that adjustments should be made to the cost range developed by GHD as part of the bottom-up analysis delivered in Phase 1.

Post-Construction Costs

Three respondents provided information on O&M costs. On decommissioning costs and other costs (such as TNUoS charges and taxes), three and two respondents provided responses, respectively.

- Fixed O&M cost estimates provided by respondents ranged from £5,000/MW to £10,000/MW, compared to GHD's low and high estimates of £12,400/MW and £16,820/MW, respectively. One respondent noted that remotely operating the site brings down staffing costs. Variable O&M costs provided by respondents range from £3/MWh to £14/MWh, with the upper end being greater than the Phase 1 high estimates at £7.74/MWh and £4.67/MWh for the two operating options (500 and 1,500 hours).
- One respondent estimated that O&M costs have been increasing 10% a year between 2021 and 2024/25. The driving factor was considered to be wage inflation. The limited availability of key skills and wage premiums were expected to be a driver of O&M costs in the near future, i.e., until 2030. It was also noted that the demand for specialist resources is global and expected to continue to push up prices.
- On refurbishment costs, one respondent noted that the owner must have confidence that they will be remunerated for the investment into refurbishing the asset as commercial viability is a key factor influencing the decision to extend the life of the asset. Other factors that were cited as influencing the decisions on refurbishment include capacity market provisions and legislation and policy, such as REMA and the potential implementation of locational pricing.
- On decommissioning costs, two respondents indicated that the value from the sale of scrap parts could be expected to cover 25%-40% of the total cost of decommissioning. Another respondent indicated that the value of the asset (and the value from sale of scrap parts) at the time of the decommissioning nets off with

the cost of decommissioning. Two respondents expected decommissioning to take a year from planning to completion, while one respondent expected decommissioning to be completed within a few months.

- One respondent also indicated that electricity network charges are approximately £60,000 a year while gas charges are around £800,000 a year. The respondent did not provide a breakdown between transmission and distribution charges.

Based on this limited set of information, we do not think that there is any evidence to adjust the variable cost range developed by GHD as part of the bottom-up analysis delivered in Phase 1. However, we note that the range of fixed O&M costs provided by all respondents is below the Phase 1 range. Therefore, it may be appropriate to assume lower fixed O&M costs for new reciprocating engine projects in the near future than the Phase 1 estimates.

Other

Respondents commented on their expectations for cost evolution for reciprocating engine projects:

- On pre-construction costs, one respondent noted that EPC contractors require significant upfront work and investment (e.g., feasibility studies) before agreeing to work and are sensitive to delays. The increased front-loading of development work and the associated extended timelines were expected to be a driver of development costs in the near future as well as the need to price-in uncertainty around regulatory requirements and connection costs. However, it was also noted by one respondent that they expect increased scrutiny of development costs in the long-term, and a reduction in overall budgets, while the need to accommodate new technologies will be pushing development costs up.

- Respondents also commented on their expectations on construction costs. While two of the respondents did not see the supply chain pressure to be mitigated in the near future, lower inflation was expected to somewhat bring the expected annual costs increases down from the peak levels seen currently. One of the respondents expected scarcity of discounts and increased premiums to be a feature of the market after 2030.

- One respondent commented on the impact of commodity prices on the cost of developing reciprocating engine projects. The respondent considered that commodity prices feed into projects costs immediately, as supply chains work on a just-in-time delivery strategy. Supply chains do however avail of cost optimisation strategies and hedging. The respondent expected costs to increase after 2030 due to commodity vendors increasing their prices in line with inflation and demand.

Respondents also provided views on the market for reciprocating engines and how it might develop in the future.

- One respondent noted that developers used to build low peaking and low efficiency plants just a few years ago, but that the market has now changed with focus on higher efficiency plants, e.g., LHV efficiency of 45%, which come with significantly higher costs. The Phase 1 cost estimates are also based on the higher efficiency plants (LVH efficiency of 44.6%).

- All respondents indicated that they did not have plans to convert the plants to include abatement technology in the future, with one respondent noting that the plant will be compatible with 20% hydrogen-blends. One of the respondents noted reciprocating engines can be operated using hydrogen, with most new engines being compatible with 20% hydrogen and 100% hydrogen with only minor modifications. Peaking plants are less suited for carbon capture due to the small scale of individual engines and the expected running profile (intermittent for short periods). The respondent supported the combustion of biomethane to enable decarbonisation readiness of these plants.

- In terms of the number and type of new reciprocating engine projects that might be developed in the near future, one respondent indicated that they expected future projects to be sized between 15MW and 25MW and made up of a number of smaller engines (1-2MW), while two other respondents expected larger plants, (20MW – 50MW and 30MW-100MW). The number of new projects to be developed in the next fifteen years was expected to be low, i.e., less than five. Respondents considered that several factors influence this development, including:

- Regulatory risks, e.g., grid reform, zonal pricing, connection costs and planning/ permitting (e.g., requirements on emissions, noise)
- Requirements and compliance costs from environmental policy (including emissions), e.g., decarbonisation readiness requirements, UKETS and prequalification for Capacity Markets.
- Reforms that influence the business case and revenue streams for smaller peaking plants, e.g., interventions that affect wholesale price volatility on which flexible generation relies, NESO market reforms that might influence returns from balancing mechanisms for smaller plants and the development of a flexibility market.
- The impact on wholesale price volatility from the retirement of existing plants, the deployment of renewable generation and storage assets, and the delivery of Clean Power 2030.

6. CONCLUSIONS

This study provides an updated assessment on the cost of developing new unabated gas-fired power projects in GB and extending the operational life of existing plants. The study was conducted in two phases.

We engaged GHD in Phase 1 to develop cost estimates using a bottom-up approach based on Thermoflow software. The results of this analysis are presented in Section 3 and Section 4. We then supplemented this analysis in Phase 2 by engaging with wider GB stakeholders that are involved in gas generation projects in GB. The findings from this engagement are discussed in Section 5.

The primary objective of Phase 2 was to verify and appraise the bottom-up estimates by incorporating stakeholders' practical experiences of the current market for new gas generation projects. This Phase also aimed to identify cost factors that may not have been fully captured in the initial analysis. For instance, as highlighted in Section 2.1, the cost of delivering new gas projects can be influenced by both site-specific factors (e.g., the suitability of a site for power plant construction) and broader market conditions, such as international supply and demand. Periods of high global demand for gas turbines and engines can strain supply chains, leading to cost increases for developers.

Stakeholders who participated in Phase 2 consistently reported that the cost of developing new gas projects has risen sharply in recent years. They attributed this increase primarily to international supply chain disruptions, the lingering effects of the Covid-19 pandemic, and heightened demand for turbines and engines in other markets. As a result, some cost estimates from Phase 2 exceeded the bottom-up estimates developed in Phase 1, as noted in Table 6.1 below.

Table 6.1: Consistency of evidence gathered between Phase 1 and Phase 2

Generation Option	Cost Type	Differences between Phase 1 and Phase 2 evidence.
CCGT	Pre-Operational Costs	The estimates provided in Phase 2 indicate that the cost of developing new CCGT plants may be above the bottom-up range developed in Phase 1.
	O&M Costs	The estimates provided in Phase 2 are broadly consistent with the bottom-up range developed in Phase 1.
CHP	Pre-Operational Costs	Insufficient evidence provided as part of Phase 2 to directly appraise the consistency of the bottom-up estimates developed in Phase 1.
	O&M Costs	Insufficient evidence provided as part of Phase 2 to directly appraise the consistency of the bottom-up estimates developed in Phase 1.
OCGT	Pre-Operational Costs	The estimates provided in Phase 2 indicate that the cost of developing new CCGT plants may be above the bottom-up range developed in Phase 1.
	O&M Costs	The estimates provided in Phase 2 are broadly consistent with the bottom-up range developed in Phase 1.
Reciprocating Engines	Pre-Operational Costs	The estimates provided in Phase 2 are broadly consistent with the bottom-up range developed in Phase 1.
	O&M Costs	The estimates provided in Phase 2 indicate that fixed O&M costs may be below the bottom-up range developed in Phase 1.

Source: CEPA analysis

As noted in Section 6, there are several limitations in interpreting the evidence gathered in Phase 2. In particular, a small number of stakeholders chose to engage with this process which limits our ability to identify a clear consensus on costs or to draw definitive conclusions from this phase.

To reconcile findings from Phase 1 and Phase 2, we first focus on cases where the cost estimates gathered in Phase 2 fall outside of the range estimated by GHD in Phase 1. In these cases, we consider that it may be appropriate to assume a higher/lower cost relative to the bottom-up estimates developed in Phase 1:

- **CCGT – pre-operational Costs**: Respondents indicated that the current cost of constructing a new CCGT plant may be 40% to 110% higher (on a £/kW basis) than the High estimates from Phase 1. Similarly, reported development costs (excluding land acquisition) ranged from 90% to 365% higher (on a $/kW basis) than the High estimates. While uncertainty remains, the evidence gathered from Phase 2 suggests that significant recent global supply chain pressures may help explain these differences. In this context, we consider that it may be appropriate to assume that new CCGT projects currently face higher pre-operational costs than what was estimated in Phase 1.
- **OCGT – pre-operational Costs**: Respondents indicated that the current cost of constructing a new OCGT plant may be 10% to 250% higher (on a £/kW basis) than the High estimates from Phase 1. The wide range suggests a significant level of uncertainty among stakeholders regarding OCGT development costs in GB. Nonetheless, the evidence suggests that costs may exceed Phase 1 estimates, and it may be appropriate to assume higher pre-operational costs for new OCGT projects.
- **Reciprocating engines – fixed O&M costs**: Respondents indicated that fixed O&M costs may be -20% to -60% lower (on a £/kW basis) than the Low estimates from Phase 1. While there remains significant uncertainty, this evidence suggests that it may be appropriate to assume that fixed O&M costs for new reciprocating engine projects may currently be lower than those estimated in Phase 1.

Appendix A PHASE 1 ASSUMPTIONS LOG

Provided in a separate attachment.

Appendix B PHASE 1 GENERATION OPTIONS HEAT BALANCE DIAGRAMS

This appendix provides a heat balance diagram for each Generation Option considered in this report. These diagrams are included to provide a technical representation of the energy flow and distribution that has been assumed for each Generation Option plant's processes, from fuel input to electricity generation and heat losses. They illustrate the conversion of chemical energy from natural gas into thermal energy in the combustor, mechanical energy in the turbine, and finally electrical energy through the generator, while accounting for inefficiencies such as heat lost in exhaust gases or cooling systems.

B.1. Heat Balance Diagram: Generation Option 1 – CCGT H Class

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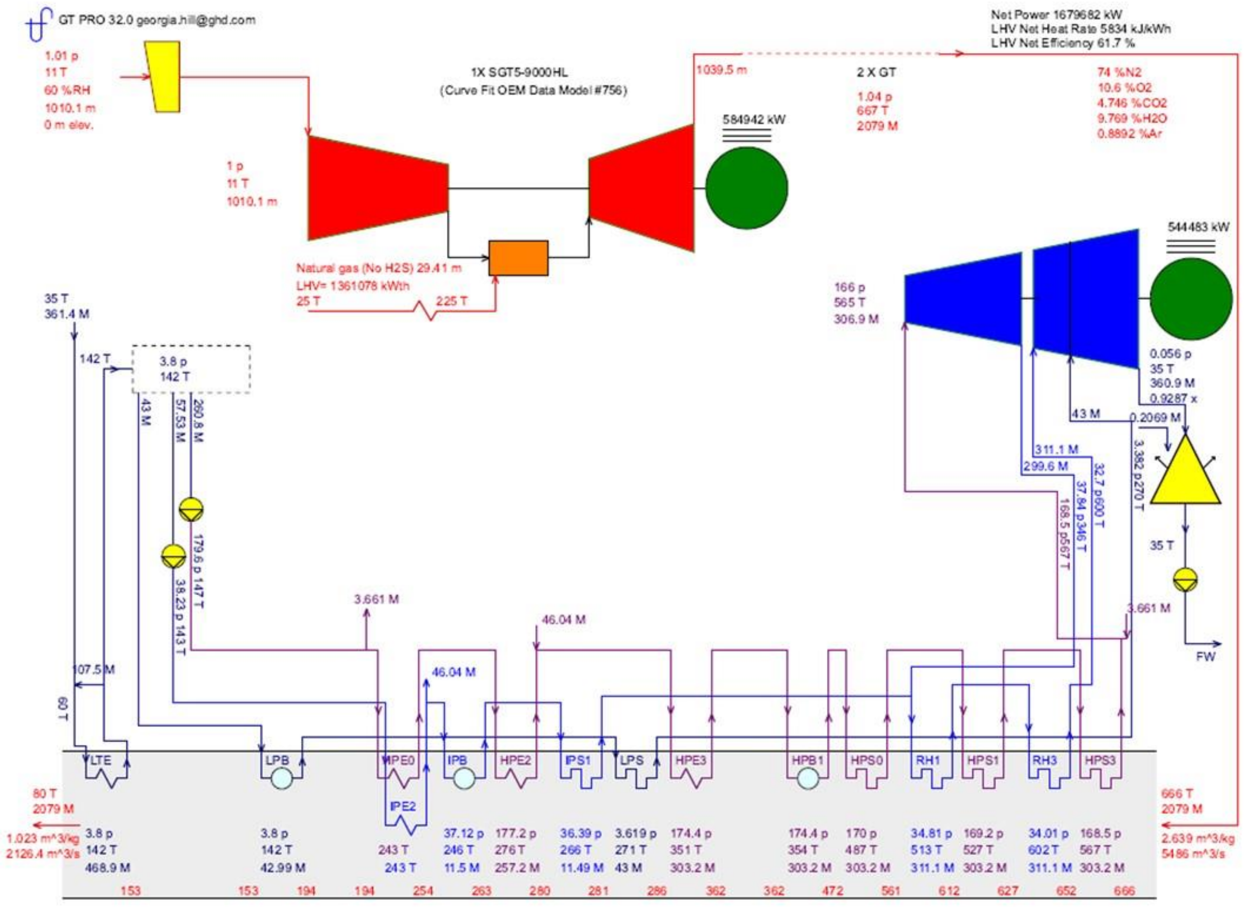

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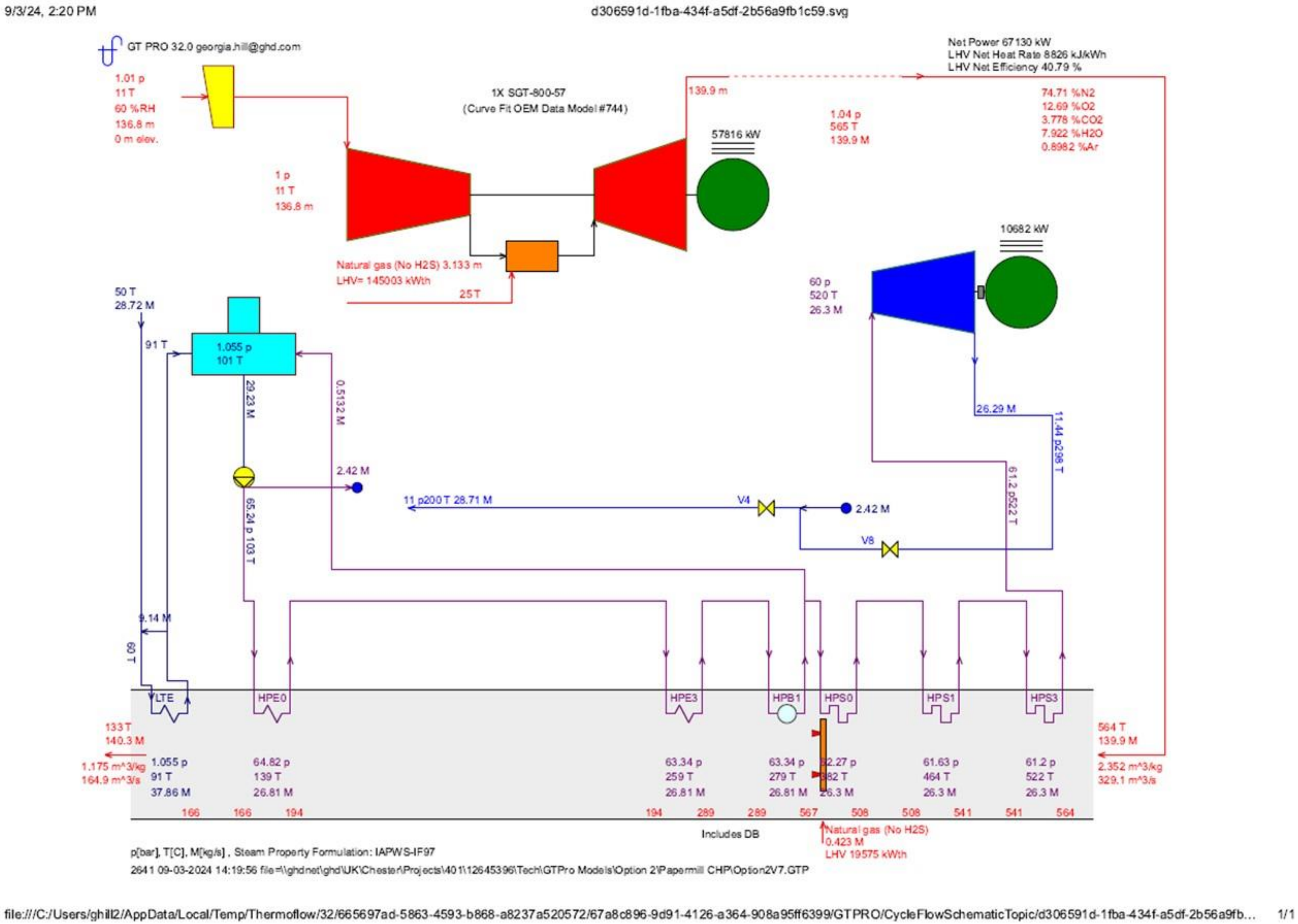
B.2. Heat Balance Diagram: Generation Option 2 – CCGT in CHP Configuration



B.3. Heat Balance Diagram: Generation Option 3 – OCGT < 300 MW

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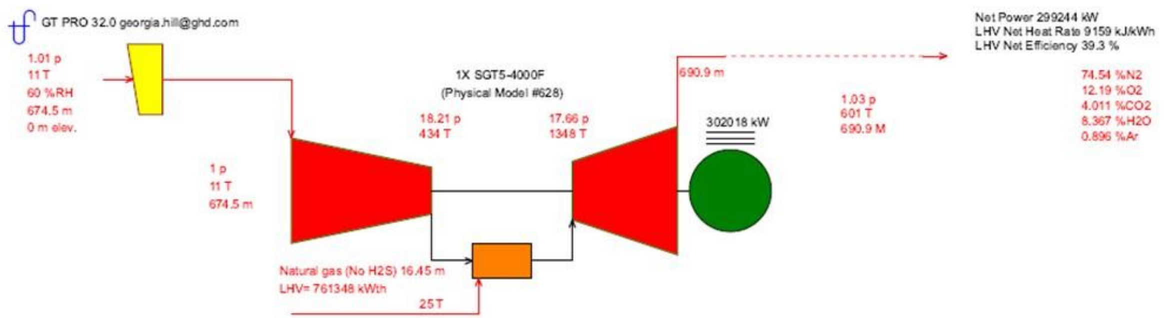

p[bar], T[C], M[kg/s] , Steam Property Formulation: IFC-67

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B.4. HEAT BALANCE DIAGRAM: GENERATION OPTION 4 – OCGT > 300 MW

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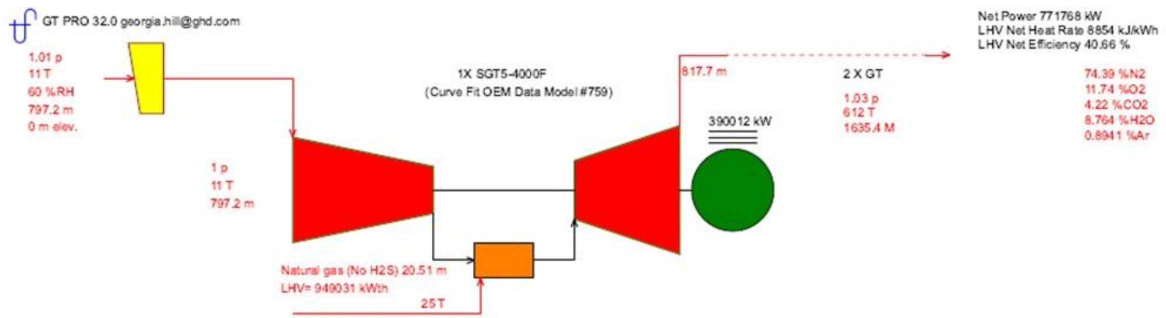

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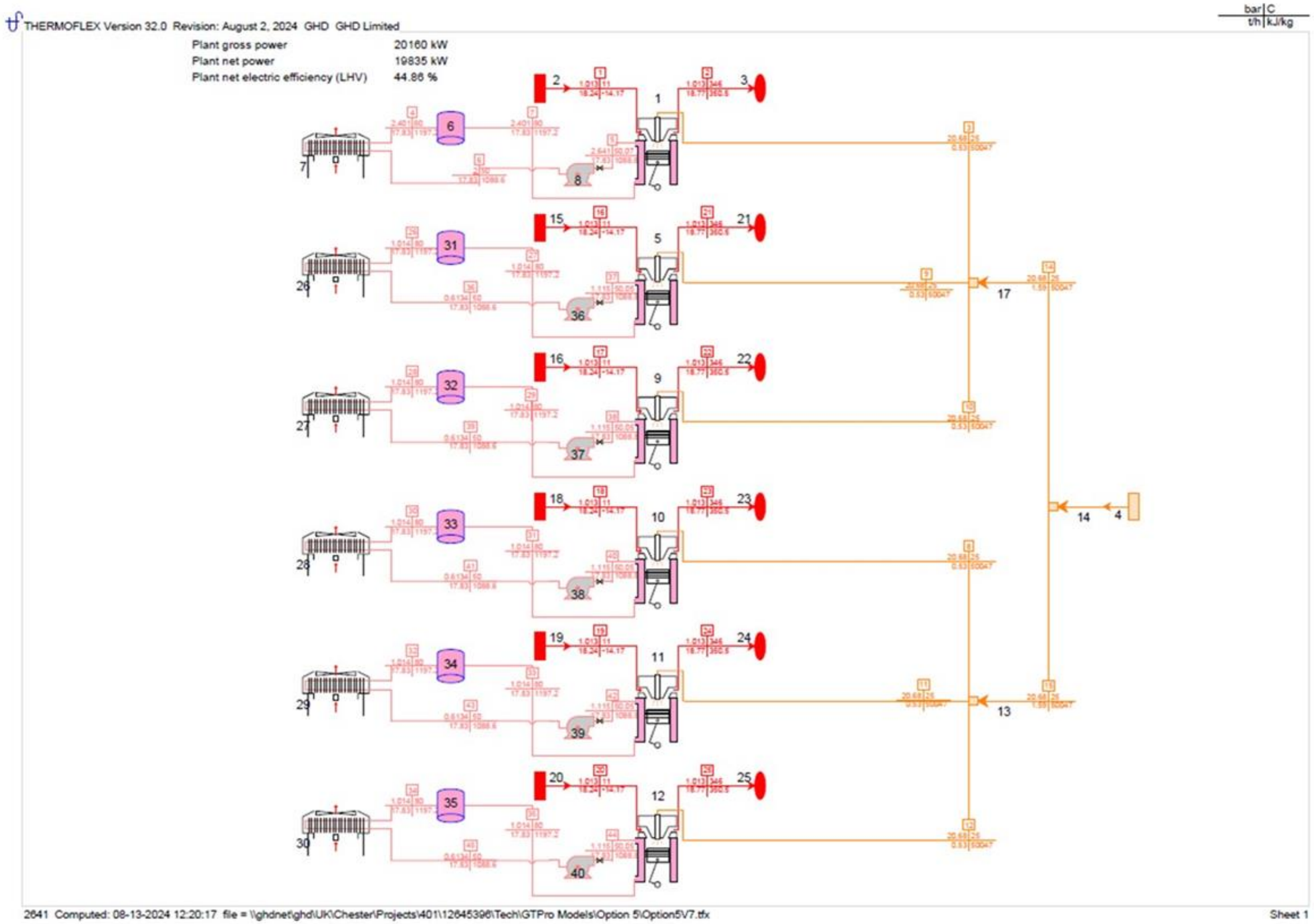
B.5. HEAT BALANCE DIAGRAM: GENERATION OPTION 5 – RECIPROCATING ENGINES



Appendix C PHASE 1 GENERATION COST BREAKDOWN

Provided in a separate attachment.

Appendix D PHASE 2 COST QUESTIONNAIRE TEMPLATE

Provided in a separate attachment.

UK

Queens House

55-56 Lincoln's Inn Fields

London WC2A 3LJ

T. **+44 (0)20 7269 0210**

E. **info@cepa.co.uk**

www.cepa.co.uk

Australia

Level 20, Tower 2 Darling Park

201 Sussex Street

Sydney NSW 2000

T. **+61 2 9006 1308**

E. **info@cepa.net.au**

www.cepa.net.au

Cepa-ltd **@cepaltd**