CORNWALL

CREATING CLARITY

Lux Nova Partners

clean energy lawyers

Heat Network Electricity Revenues & Licencing Guidance

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About Cornwall

Cornwall's team of independent specialists have experience of liberalised energy markets and their regulation since their inception in Great Britain and elsewhere in the late 1980s. We provide consultancy, intelligence and training, and are a trusted and reliable partner whether you are a new entrant or a large, established player.

Specific areas of our expertise include:

- Wholesale and retail energy market competition and change
- Regulation and public policy within both electricity and gas markets
- Electricity and gas market design, governance and business processes; and market entry

About Lux Nova

Lux Nova Partners is a team of experienced City pedigree energy and commercial lawyers who have been working together in the clean energy space for many years, who decided to set up Lux Nova as a new kind of law firm focussed exclusively on meeting the needs of the clean energy market.

We have four main business lines: renewable generation (UK and emerging markets), alternative routes to (the electricity) market, district heating and cooling and energy efficiency, and are committed to making a positive contribution towards development of the sector.

Disclaimer

This report has been prepared by Cornwall Insight and Lux nova Partners.

This report does not address the full project cycle to developing or operating an electricity generating station. Nor does it explore in any depth issues relating to heat off-take. Instead, it focusses specifically on electricity revenues from distribution connected CHP.

This report makes use of information gathered from a variety of sources in the public domain and from confidential research that has not been subject to independent verification. No representation or warranty is given by the authors of this report as to the accuracy or completeness of any such information.

Nor does this report take into account the specific facts and circumstances relevant to any particular project that the reader may be involved in. It is not intended to be (nor can it be) a substitute for taking project-specific advice from competent advisors, which anyone reading this report is strongly urged to take.

The authors of this report do not accept any liability to anyone for any loss or damage they may suffer, howsoever caused, arising from their reliance on this report or anything contained or referred to in it.

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Executive Summary

1.1 Purpose

The Government aim to decarbonise the GB economy has led to an increased take up of heat networks within GB in recent years. The provision of heat to feed into heat networks can be produced from various sources, but the most popular is to use a gas fired Combined Heat and Power (CHP) power station. The use of CHP enables heat and power to be provided to end customers with a high degree of efficiency. Where a power station is used to provide heat, one of the key considerations is how to maximise the income from the electrical export from the site. This guidance note is designed to provide information relating to the routes to market for this electrical output and how the most appropriate route can be selected.

The GB electricity market is complex and fully explaining its function and the roles and responsibilities of different market players is beyond the scope of this guidance.

It is assumed the reader has some awareness of the workings of the market (e.g. the requirement for licensing of generation, distribution and supply activity – see section 6.2) but no detailed knowledge is assumed.

1.2 Direct and indirect routes to market

These guidance notes identify eight distinct routes to market for the electrical outputfrom plant[1] connected to a district heating scheme (Chapter 4). These routes can be split into two primary categories:

- DIRECT – power is sold directly to customers or used on the same site as it is generated. The power never enters the public network.
- INDIRECT – power is sold onto the public network. This means that the units are allocated to an electricity supplier.

These two categories are not mutually exclusive. It is common for power to be sold directly to a customer via a private wire, with the excess "spilled" onto the public network.

DIRECT ROUTES TO MARKET

The direct route to market can be split into two categories and these routes are appraised within the guidance notes:

1. Self-supply – where the power from a CHP is consumed by the same individual or corporate entity either on the same site or via a private wire.
2. Private wire – where the power is used to supply a third party via a private wire.

These activities will typically rely on one of several existing supply licence class exemptions. A private wire route will probably involve distribution activity whereas self-supply may not; in many cases a distribution licence class exemption can be relied upon but this will also need to be confirmed. See sections 1.4 and 6.2.4 and 6.2.6

INDIRECT ROUTES TO MARKET – POWER PURCHASE AGREEMENTS

Where an indirect route to market is the preferred option, six options exist which can be split into two categories. Firstly, the generator can contract with a supplier using a Power Purchase Agreement (PPA). This contractual agreement enables the generator to transfer the power generated to an electricity supplier who manages the sale of this power into the wholesale market and pays the generator any revenue associated with its export.

There are several types of PPA:

3. A standard PPA is the most basic form of PPA. These agreements are relatively standardised and can be procured easily and quickly directly from suppliers or through an online auction platform.

[1] Generally assumed to be licence exempt embedded[4] generation – see 6.2.3

Consequently, this route to market is selected by many participants, particularly new entrants and it can be considered as the baseline or counterfactual against which other options are measured.

However, for generators looking to enhance their earnings or looking for longer term agreements, there are several variations to the standard PPA that may be used which are collectively referred to as corporate PPAs. Corporate PPAs is the terminology used to describe agreements between generators and end customers where the electricity still flows via the public network, but with a supplier that is required to sit between the generator and end customer to implement the agreement. Corporate PPAs can be further split into two sub-categories:

4. Sleeving/ Peer to Peer – This is where a generator agrees to supply a customer (who could in some circumstances be the same legal entity e.g. a Local Authority) and utilises a licensed supplier to implement the deal. A sleeving agreement is where a (usually bilateral) deal is struck between the generator and end customer and taken to the supplier for implementation. A Peer to Peer agreement is implemented in a similar way, but the generator contracts with the end customers through a Peer to Peer platform that matches generation and demand customers. The agreements are then implemented via a supplier.
5. Synthetic PPA – A direct agreement between a generator and end customer that hedges the wholesale price element of the electricity bill using a Contract for Difference[2] approach.

INDIRECT ROUTES TO MARKET – SUPPLIER ROUTE

An alternative route to market from selling a PPA is for a generator to become or partner with a licenced electricity supplier. This is a much bigger undertaking for a generator and brings with it both new risks that need to be managed, but also additional opportunities by allowing the generator direct access to end consumers across the public network and the ability to participate directly in the wholesale market. Where such a supplier route to market is adopted, it is a licenced activity and three options exist[3]:

6. Full licence – Entity becomes a fully licensed supplier and the export units are allocated to the supplier.
7. Licence lite – Entity becomes a licensed supplier, but the licence excludes the requirements to accede to industry codes. The Licence Lite supplier must contract with a fully licensed supplier to provide this element of the service.
8. White label – Entity partners with a licensed supplier to offer electricity tariffs, typically on a commission based agreement.

1.3 Comparison of routes to market

Choosing a route to market will depend on the strategic objectives of the stakeholders involved in the project (Chapter 5). This may mean that the most economic route is not always the most appropriate. For instance, choosing a White Label supply route to market may not be economic for a small portfolio of demand customers due to the low margins achievable. However, it may enable a Local Authority to reduce fuel poverty by engaging with customers who have never moved electricity supplier and assist them to move to a competitive tariff.

From a purely economic perspective, the choice between routes to market will vary from site to site. However, a general hierarchy between the route to market options is as follows:

1) Self-supply – Most economic route as offsets full demand cost.

[2] A CfD is a financial instrument that fixes a price (labelled the strike price) for a commodity or service in the future between two parties. Where the outturn price differs from the agreed price, one party will make a payment to the other to ensure that both parties remain in the same financial position as if there had been no change to the underlying market price.
[3] Some supply activities are licence exempt (e.g. the options for a direct route to market will typically rely on a supply licence class exemption), however, the existing class exemptions do not allow electricity supply across the public network without the involvement of a supplier. Technically a 'ninth' route to market exists which would require a change to existing licence exmptions, application for a new supply licence exemption and/or changes to various regulations and codes and so is not included in this report; see 4.2.5

2) Private wire – Offsets full demand costs of end users, but additional cost associated with private wire, plus some complexity on contractual arrangements.
3) Supplier route – Becoming a supplier, either White Label, Licence Lite or full licence, can enhance earnings when compared to a PPA route, but a minimum size portfolio needs to be acquired in each case to recover the fixed costs.
4) Corporate PPA route – Using a peer-to-peer, sleeving or synthetic PPA can result in improved margins compared to a standard PPA.
5) Standard PPA – A simple, low risk route to market, but revenue may be lower than the routes to market above.

The commercial aspects of the routes to market are examined in more detail in Chapter 7. This chapter provides some illustrative examples of the value that can be earned for a CHP under each route to market in 2017-18. The analysis undertaken compares the additional revenues compared to a standard PPA basecase or what could be classed as the counterfactual.

A summary of the results of the analysis is shown in Figure 1:

Figure 1: Comparison of routes to market relative to a standard PPA as calculated in later in this document

Self-Supply	32% - 46%	Yes	Large uplift on baseline PPA achievable
Private Wire	8% - 30%	Yes	Uplift on baseline PPA achievable, but additional costs of private wire and providing discount to end customer need to be considered. Business case assumes electricity demand will exist for the life of ;the power station.
Full Licence	5% - 10% plus supply margin	Some protection against wholesale market movements	Potential to improve the terms of the PPA by linking to own supplier. Supply business must be profitable to make route to market viable. Offers some protection against wholesale market volatility.
Licence Lite	5% - 10% plus supply margin		
White Label	2% – 4% plus supply margin		
Sleeving/ Peer to Peer	0.4% - 1.1%	Yes	Captures a small proportion of the supply margin. Offers long term security which reduces risk but may be financially beneficial or detrimental depending on market movements.
Synthetic PPA	0%	Yes	No uplift compared to a standard PPA, but offers long term security which reduces risk but may be financially beneficial or detrimental depending on market movements.

1.4 Regulatory Considerations

A further consideration when comparing routes to market is regulatory constraints. These constraints may mean that some routes to market are not possible for a project and it is therefore important that these are considered at an early stage in the planning process. The three key areas of regulatory constraints are described in Chapter 6:

- The class exemptions from the requirement to hold an electricity supply and/ or distribution licence
- The restrictions that may apply to a local authority's powers to sell electricity
- The way in which State Aid impacts on what a local authority can do or how it provides support

Where a project is relying on a class exemption it is normally down to the relevant stakeholder to ensure they are compliant with the legislation rather than applying for permission. Therefore, a thorough appraisal, including professional advice, should be adopted to ensure a party is not in breach.

1.5 Changes to the regulatory environment

The regulatory environment for embedded generators is currently subject to a review that is likely to result in substantial change to the revenue streams available. Chapter 10 provides an overview of potential areas of regulatory change including the Ofgem June 2017 decision that will see the Triad benefit for embedded generation[4], which is currently valued at around £47/kW, reduced to close to zero from April 2020. It is recommended that stakeholders take professional advice to ascertain the most up to date position on regulatory change and the impact it could have for their projects.

1.6 Case Studies

Case studies have been developed (Appendix 1) and provide a useful insight into the practical issues faced by developers. Relevant extracts from the case studies are presented within the guidance notes to illustrate points.

1.7 Summary

These notes are designed to provide information and give guidance on the routes to market that are available for the electrical output from an embedded generator that is also providing heat into a heat network. However, the assessment of each project needs to be undertaken on a site-specific basis as the individual circumstances of the plant and the stakeholders involved will ultimately determine the best route to market.

These guidance notes are published by Cornwall Insight. If you have any queries, please contact us using the following mailbox:

enquiries@cornwall-insight.com

[4] Embedded generation, or distribution connected generation, or distributed generation, is generation connected directly to the distribution network (i.e. one of the 14 DNOs) as opposed to the transmission network (i.e. National Grid in England and Wales, one of the two transmission networks in Scotland or one of the offshore transmission networks). Note that there is no reason why CHP plant *must* connect to the distribution network – large installations (e.g. tens of MW of electrical export capacity) outside or on the edge of urban areas may find it possible and preferable to connect to the transmission network instead.

2 Introduction

2.1 Document purpose

This document has been issued by Cornwall Insight to provide a set of guidance notes to assist stakeholders with maximising income from the generation export associated with a heat network.

Under the current regulatory arrangements there are a number of options open to the owner of a CHP to sell the electrical generation via different routes to market. Each option has advantages and disadvantages that need to be carefully assessed in the context of the individual characteristics of the site and the strategic considerations of the owner organisation. This document provides guidance notes to help stakeholders assess these routes to market and select the route that will prove most beneficial in the short and longer term.

2.2 How to use this document

This document is designed to be used as an interactive document. To keep the guidance notes reasonably concise, some of the more detailed information is provided in the appendices and links are provided where appropriate. A summary document is also available which provides a high-level introduction to these guidance notes.

2.3 Guidance note limitations

This guidance provides points for consideration and should not be treated as advice.

The guidance notes consider the potential routes to market for distribution connected[4] CHPs only. It does not consider routes to market for large transmission connected generation. These sites are normally much larger than distribution connected generators and therefore become separate entities under the Balancing and Settlement Code (BSC). This means that they can trade their own energy and adopt a different route to market compared to smaller embedded generators, such as CHPs, who do not have the option to trade their energy directly into the wholesale market unless they gain a supply licence.

These guidance notes recognise that storage may be a complimentary technology to CHPs. Storage assets installed alongside CHP have the potential to increase energy market services. Although this document is not designed to provide an in-depth assessment of the costs and benefits of combining heat and electrical storage with a CHP, reference is made to storage in recognition of the importance of this emerging technology which has the potential to add significant value to projects in the future.

3 Background

This chapter provides a background to the electricity industry and the provision of heat networks via Combined Heat and Power. The following areas covered within this section are:

- An Introduction to CHP
- Electricity industry overview
- How distributed generators export power
- Embedded benefits
- Subsidies and the capacity market
- Heat networks/markets

3.1 Introduction to Combined Heat and Power

Combined Heat and Power (CHP) is the name given to a variety of technologies that simultaneously generate useable heat and electricity. This process is also known as cogeneration, or trigeneration where cooling is provided. Typically, technologies are powered by a reciprocating engine or gas turbine connected to an electrical generator, with combustion heat from this process captured to provide hot water or even cooling. This heat can be transferred and sold to customers via a heat network rather than simply venting it into the environment.

The size of CHP plant required is usually calculated based on the heat needed, in order to maximise efficiencies. This means that the amount of electricity generated from the CHP is unlikely to continually match the electrical consumption of customers. Consequently, additional electricity is likely to be imported or excess electricity exported to the public network. This mismatch is likely to vary across different time periods, both within day and across the year and presents an opportunity for operators of the CHP to optimise their output and maximise the profitability of the scheme, particularly where heat storage, electricity storage or backup boilers are present.

In terms of economic benefit, CHP is most effective where there is a continuous and stable heat requirement that allows the CHP to operate at a high load factor. The stability of the heat requirement is likely to be enhanced when there is a range of customers with different heat demands – for example offices and domestic dwellings, which require heating during the workday and evenings/ weekends respectively. Alternatively heat stores facilitate time-shifting to maximise the value of electricity generation – see below.

Heat stores

Heat stores can be used to maximise the financial returns of a CHP as they allow plant to run independently of heat requirements, with the hot water stored until needed. Therefore, electricity can be generated at peak periods, producing much higher returns than might otherwise be the case. Electricity prices at peak times can be multiple values of off-peak prices. While there will be heat losses, a properly insulated heat store can minimise these to single-digit percentages.

3.1.1 The market for CHP[5]

There were 2,102 CHP installations in GB at the end of 2015 with a combined electrical generation capacity of 5.7GW. Installed CHP capacity has hovered around 5.7-5.9GW between 2011 and 2015, peaking in 2012 at 5.96GW. The number of schemes has increased year-on-year, from 1,789 in 2011 to 2,102 in 2015, which

[5] Data within this section is sourced from: Digest of UK Energy Statistics (DUKES) 2016

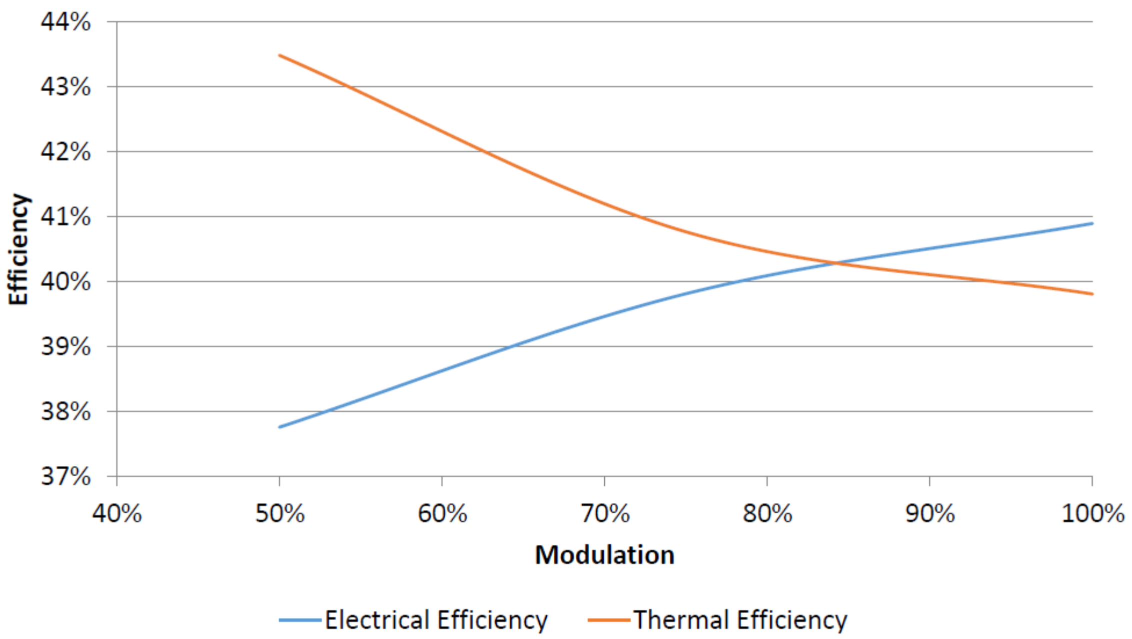
implies that there are now a larger number of smaller installations. The overall average efficiency was 72% over the 2011-2015 period, with the calorific value of the fuel used being converted to 24% electrical energy, and 48% useable heat energy, with just 28% wasted.

The majority of CHP installations are small – 82% are under 1MWe[6], including 29% under 100kWe[7]. However, these produce just 5.8% of the total electricity generated by CHP plant. The 66 largest installations – those over 10MW – produce 77% of the energy. In 2015, the average installation operated for 3,496 hours, or 9.5 hours a day.

3.1.2 CHP technology and efficiency

The main benefit of CHP technology over separate heating and electricity generation is the efficiency gains from combining the two processes. The best coal-fired power stations convert around 40-45% of the calorific value of the fuel to useable energy. New combined cycle gas turbines (CCGT) can achieve 60% efficiency, but the average efficiency in the UK was 48% in 2015. The average existing CHP systems in the UK achieves 72% efficiency and many newer installations can exceed 87% efficiency[8]. This efficiency is relatively stable, even when the output of the CHP is altered. The graph below shows how both electrical and thermal efficiency changes when the level of generation varies for a gas reciprocating engine above 50% loading[9].:

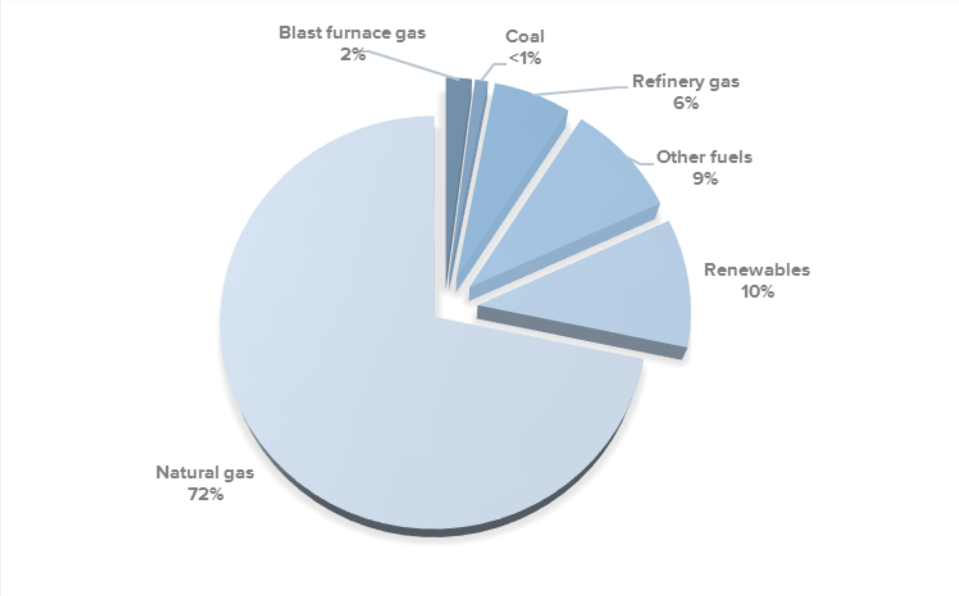
Figure 2: Typical efficiency load curve for gas fired CHP[10]



There are a range of fuel sources that are used by CHP plant. The chart below shows the proportion of each fuel type used in 2015.

[6] MWe - Mega Watts (electrical)
[7] kWe - kilo Watts (electrical)
[8] Note that all CHP efficiency figures used in this chapter are the gross calorific values, also known as the higher heating value (HHV). This will result in a lower efficiency score than if based on the net calorific value or lower heating value (LHV). The difference between gross and net values is the heat associated with the evaporation of water from the fuel, which is unrecoverable
[9] The chart excludes loading below 50% as stable generation may not achievable for some power stations below this level
[10] The Chartered Institution of Building Services Engineers (CIBSE) - Combined Heat and Power, Opportunities and Risks

Figure 3: Summary of CHP fuel use in 2015[11]



The greater efficiency of CHP compared to standard generation results in reduced carbon production for GB consumers. In 2015, it is estimated that the use of CHP plant saved 12.47MtCO_2, or 2.19MtCO_2/1,000MWe, when compared to fossil fuel generation. If CHP emissions are compared to the current UK generation mix, 6.29MtCO_2 or 1.11MtCO_2/1,000MWe was saved.

There are four main types of CHP plant identified below. The suitability for an installation will depend on the requirements – size of plant, heat and electricity output requirements, fuels available or desirable.

Steam turbine

High pressure steam is generated in a boiler and used to power a turbine, which generates electricity.

In back-pressure steam turbines, the steam is used to power the turbine until it drops to a lower pressure where it is generally used in another process, some could be available for use in a heat network. In condensing steam turbines, some of the steam is usually extracted at various pressures, to be re-heated and used in the turbine again, increasing efficiency; most of the remainder is available to be released into a heat network. The balance goes to the condenser.

The boilers can be fired by coal, gas (or biogas), oil, biomass, waste, or a combination of fuels. Efficiency ranges from 10-20% for electricity, 30-70% for heating.

Installations range widely in size from several MWe to over 100MWe.

Gas turbine

Often based on aeroplane engines, gas turbines generally burn gas or an oil to directly power the turbine. Exhaust gases provide heat, usually by heating water in a waste heat boiler, though sometimes the gases are used to provide heat directly. The waste heat boiler may include ‘supplementary’ or ‘auxiliary’ firing using various fuels, typically natural gas.

Electrical efficiency varies between 23-38%, dependant on the size of the unit. Gas turbines can provide up to 50% efficiency for heating, though this will depend on auxiliary firing of the waste heat boiler and installation size ranges from 30kWe upward.

[11] *Source - https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/540963/Chapter_7_web.pdf*

Reciprocating engine systems

A reciprocating engine CHP utilises a similar technology to a car or boat engine and is normally fuelled by gas. This technology is mainly used where hot water, rather than steam, is the main heat requirement. These systems provide several grades of heat: the hotter engine exhaust (<500°C) and the cooler engine radiator output(<95°C). Systems making use of turbochargers produce a third grade of heat, known as intercooler heat in two stages. First-stage intercoolers result in temperatures as high as 200 °C, which is combined with exhaust gases. The second stage intercoolers produce a much lower concentration of heat, around 55°C. Steam and water heating systems tend to be too high temperature to make use of this heat, but some installations are able to make use of this heat directly to heat space or in industrial drying processes.

Based on the higher heating value the electrical efficiency can range from around 25% for smaller engines (around 100kWe) up to around 40% for 4MWe gas engines[12]. Electricity efficiency's will be higher when an engine runs at full capacity and decline at lower loading levels. Heating efficiency is also altered by loading levels with higher heat efficiency at the lower end of the turndown rate typically ranging between 36-54%[13].

Installation size can be from under 0.1MWe to around 5MWe. This type of CHP tends to be the unit of choice for heat networks.

Combined cycle systems

Combined cycle systems combine two unit types. For example, the usual arrangement is gas turbines, to generate directly, with the exhaust gases used to generate steam to power steam turbines. Less commonly, reciprocating engines are used instead of gas turbines.

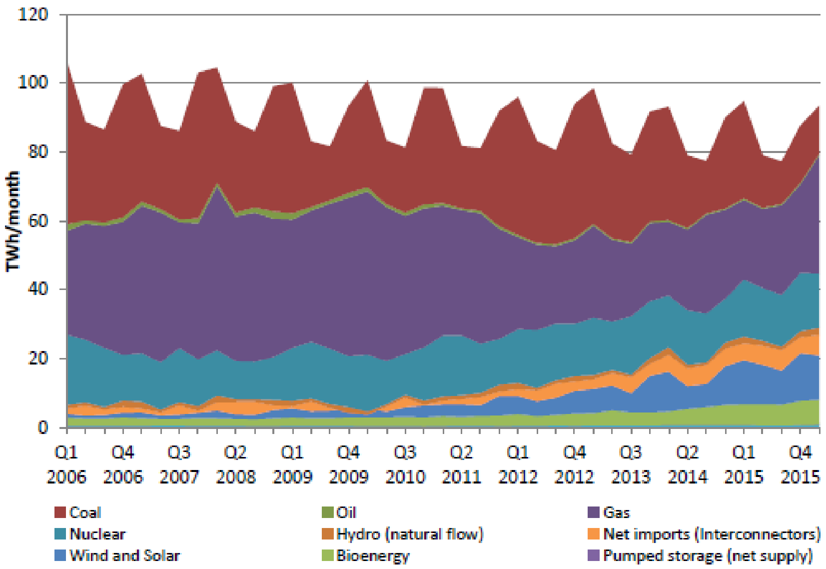
In modern plant, electrical efficiency can approach 50%, with heating efficiency of 20% for a total of 70% efficiency. Installations are suited to larger plant of 7MWe and above.

3.2 Electricity industry overview

The GB electricity system is dominated by large-scale power stations connected at the transmission level. Total transmission connected generation capacity is around 62GW[14] in 2016-17 and around 28GW of embedded generation see 3.2.1. CCGT[15] plant supplies over a third of all electricity, with nuclear and coal stations supplying approximately a sixth each, and the remaining third provided by renewables along with interconnectors to other countries. The generation mix has changed over the last five years with more renewable power on the system and a reduction in coal. This trend is likely to continue and the graph below shows how the fuel mix changed between 2006 and 2015.

[12] Source: Carbon Trust: Introducing combined heat and power
[13] Source: DECC: CHP Technology - A detailed guide for CHP developers – Part 2
[14] Based on chargeable Transmission Entry Capacity (TEC) for 2016-17 as published by National Grid in their 5 year forecast on 11 February 2016
[15] Combined Cycle Gas Turbine.

Figure 4: Electricity generation mix by quarter and fuel source[16]



Generators are owned and operated by a wide variety of parties, from the Big Six energy companies to independent merchant generators. Some companies only own one power plant –such as Drax, which runs a large coal-fired plant in North Yorkshire that has been partly converted to run on biomass – but other companies own many stations.

Transmission networks in England and Wales operate at 400kV or 275kV. It should be noted, that the Scottish transmission network includes 132kV networks which in England and Wales are classified as distribution. This high voltage results in losses on the transmission system at around 1.7%. The distribution network operates at lower voltages and losses are higher with average losses of around 6%.

The transmission network in England and Wales is owned by National Grid. The Scottish transmission system is owned by two companies, Scottish Power in the South and Scottish Hydro Electric in the North. New offshore transmission owners (OFTOs) are also emerging as large scale offshore wind farms are constructed. These OFTO companies operate under licence and are responsible for maintaining their transmission networks.

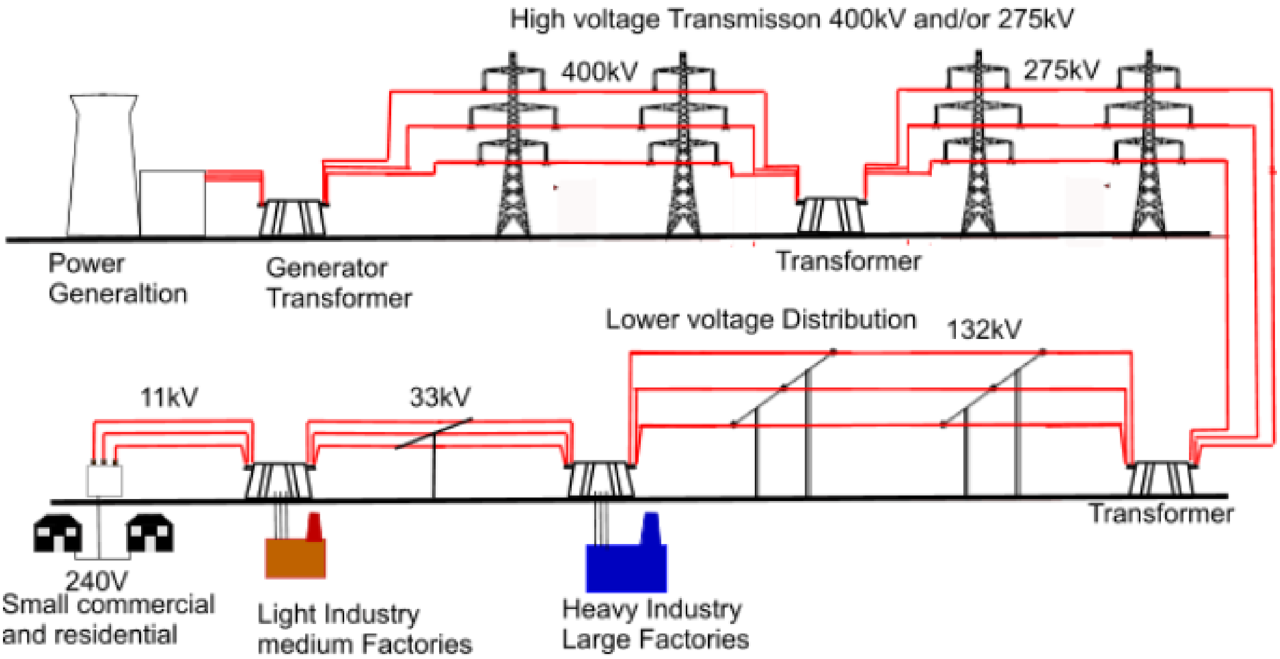
National Grid Electricity Transmission has a separate role as the GB System Operator (SO). It is responsible for ensuring that the whole transmission system is operated safely. It does this by managing the frequency across the system and calls upon market participants to adjust output over a variety of timescale to keep supply and demand balanced within operational limits. (via a range of mechanisms to reward/penalise action)

The transmission system is physically connected to the 14 GB distribution networks by Grid Supply Points (GSPs). The Distribution Network Operators (DNOs) are owned and operated by six companies who are responsible for the safe operation of the lower voltage system where most consumers are located. The DNO's networks consist of several voltages with the highest voltage (in England and Wales) being 132kV. Voltage steps down through 33kV at bulk supply points (BSPs), 11kV at primary substations and finally secondary substations, where small business and household supply customers are connected at 400V or 230V. The connection voltage will be a key determinate of the charges faced by a user of the network.

To put this into context, each GSP supplies roughly six BSPs, each of which has roughly six primary substations. A primary substation will feed around 20 secondary substations. The diagram below provides an illustration of how power flows from generators on the transmission network to end customers.

Figure 5: Transmission and distribution voltages

[16] Ofgem Wholesale Energy Markets in 2016



3.2.1 Distributed Generation

Locating small scale generation within the distribution network avoids costs associated with moving power longer distances across the transmission system. Much of the generation has also been made possible through renewable subsidy to augment conventional market revenue. Generators range from household sized installations (e.g. roof top solar photovVoltaic (PV)) to relatively large (e.g. tens of MW) generation from both renewable (e.g. onshore wind farms, energy-from-waste, solar PV farms) and non-renewable sources.

Most local distributed generation is renewable, but significant amounts are fossil-fuel powered, including some CHP installations. Total distributed capacity has grown from around 12GW in 2011 to 24GW in 2015; it is estimated that there is around 28GW[17] in 2016, which is a significant addition to the 62GW connected to the transmission networks.

3.3 Heat networks overview

A heat network, or district heating scheme[18], provides heating for multiple customers within a building (sometimes referred to as communal heating) or number of buildings (referred to as district heating) using a centralised generation system. Water is heated—or more rarely, converted to steam—before being piped throughout a building (communal) or across the local area (district). Typically, where a heat network spans multiple buildings, heat exchangers are used to hydraulically separate the central system from local systems, allowing different pressures and rates of circulation and easier control of temperatures (and ownership) in local buildings.

The Manhattan district heating network, the largest in the world, provides electricity and steam for heating, cooling and industrial processes to over three million people. In Denmark, over 60% of space and water heating is by district heating system. In Iceland, 95% of houses are on heat networks, mostly using excess hot water from three geothermal power plants. In the UK, a 2013 DECC report showed 2,000 networks serving 210,000 homes and businesses.

[17] Estimate provided by Energy Networks Association - Transmission and Distribution Interface Steering Group Report
[18] The Heat Network Metering and Billing Regulations distinguish district heating (a heat network serving multiple buildings) from communal heating (a heat network serving multiple customers in the same building)

Electricity and heat networks can interact in a number of ways. Most UK CHP systems use the combustion of fuel to generate electricity, supplying the excess power to the grid and waste heat to the heat network. Alternatively, electrically powered heat sources could be installed on the heat network, for example with the electricity from CHP used to power a local heat pump at times of excess capacity. The resulting heat could either be used immediately or stored in a heat store for later use.

3.4 How does distributed generation export power?

The GB electricity market regulatory framework is predicated on the basis that users of the distribution network are primarily customers that consume electricity from power generated by large-scale transmission connected generation. To ensure orderly market operation the licensed supplier is the industry party responsible for registering meters and paying charges arising from flowing electricity to the meter across the networks.

Meters for distributed generation (in all but the very largest of cases) are also managed by suppliers, as they are the industry party accredited to manage the associated data flows that ensure allocation of energy and charges to the correct party.

For this reason, a generator connected at the distribution level that is seeking to sell its output into the wider markets across the public networks must have its metering registered by an authorised party—i.e. a supplier that is required by their licence to become signatory to the necessary industry codes detailing market operation. See also sections 4.2.3 and 4.5.

This arrangement gives rise to the Power Purchase Agreement (PPA) or offtake agreement that sets out the terms and conditions, including the price, under which electricity is sold to the supplier. The supplier, as the registrant of the generation meter, acts as the route to market where the power can be sold onwards or, more typically, consumed by the supplier's own customers within the same distribution network. The PPA can be a standardised agreement or bespoke and typically cover a period ranging from 6 months to 15 years.

The alternative route to market for a distributed generator is to export its power direct to an end customer, without using the distribution or transmission networks. In this case, a contract can be agreed between the generator and the customer that specifies the terms and conditions under which the power will be sold across a private network / wire. Where power is sold direct to a customer, the supplier of the electricity will either need supply and distribution licences or to satisfy themselves that they are exempt from the need to hold such licences. More detail on the routes to market is contained in Chapter 4

and information relating to exemptions are contained in Chapter 6.

3.4.1 Behind the meter generation

Behind the meter generation refers to the practice of connecting generation to users without using the public network (either transmission or distribution); for example, using solar panels to offset the electricity needs of a factory. Behind the meter generation is one of the routes to market considered within Chapter 4 (see especially 4.4.2 and 4.4.3) and is classified as a direct route to market because it avoids use of the public network. The guidance notes terminology used for behind the meter generation is either "**self-supply**" or "**private wire**".

One consequence of using a direct connection means that volumes of production and use are not monitored or visible to market players, such as suppliers or in some circumstance the System Operator. This is not normally an issue unless the generation becomes unavailable and the demand reverts to consuming power through the public networks. Behind the meter generation also allows avoidance of several costs which licenced suppliers will incur and recharge to their customers including network charges, system balancing charges, and low-carbon programme support costs.

Ofgem may be bringing forward regulatory change in this area. Chapter 10 provides more information on why this is an issue.

3.4.2 Distribution network constraints

Due to the substantial number of embedded generators connecting to the distribution network, it is becoming increasingly difficult for new generation to connect without causing significant reinforcement costs. These costs are charged in full to the generator or shared between the generator and distributor. The expense of connection costs can act as a barrier to new plant connecting in certain areas which are already saturated with embedded generation. Distributors are implementing Active Network Management Schemes (ANMS) to help them manage the large amount of embedded plant that are connecting to their networks and generators can choose to participate in these schemes to avoid potentially high connection costs. These schemes may result in the export from a generator being curtailed under certain conditions, but in return they are able to connect more quickly with less upfront costs. More information about ANMS is available from the Best Practice Guide published by the Energy Networks Association (ENA).

3.5 Embedded benefits

Distributed generation can receive benefits by virtue of being embedded within the distribution system commonly referred to as "embedded benefits" and a detailed description of these are contained in Appendix 4. Embedded benefits arise from the avoidance of charges associated with the transmission network and the receipt of credits from the distribution network. A summary of the categories of embedded benefits is shown below:

- Embedded generators, under 100MW in size, avoid paying transmission network use of system (TNUoS) charges which is a charge incurred by transmission connected generators[19].
- Embedded generators offset costs for suppliers who are charged on a net basis. The suppliers pass these savings on to the generator in the form of a credit. This includes credits for the following items:
    - TNUoS charges that are levied on suppliers (known as the **Triad benefit**)
    - Balancing Services Use of System (BSUoS) charges
    - Capacity Market Supplier Charge (CMSC)
    - Assistance for Areas with High Distribution Costs (AAHDC)
    - Residual Cashflow Reallocation Cashflow (RCRC)
- Network losses can be reduced at distribution and transmission and this results in a credit for embedded generation, through the scaling up of the export volume.
- Distribution Use of System charges (DUoS) - DNOs provide DUoS credits to most embedded generation to reflect the reduction in their costs that result from the presence of embedded generation.

The value of embedded benefits can be substantial to a distributed generator and Ofgem is concerned that they may no longer align with the costs savings that accrue from these generators connecting at distribution level rather than transmission. Ofgem is reviewing this area and this is likely to result in a reduction in the level of embedded benefits in the future. More detail on the review can be viewed in Chapter 10.

3.6 Subsidies and the capacity market

There are several central government subsidies available to operators of CHP facilities as secondary revenue streams. Operators may also choose to attempt to access the capacity market auctions. However, generally only one subsidy *or* the capacity market can be accessed at any one time. Furthermore, the design of the CHP installation is likely to dictate which subsidy will be available.

[19] Transmission connected generation pay to use the transmission system. In most cases this is a cost, but in certain areas it may be a credit.

Access to most of the subsidies requires the operator to obtain a combined heat and power quality assurance (CHPQA) certificate, and submit this to BEIS to secure a Secretary of State combined heat and power certificate (SoS certificate).

The sections below provide a summary of the subsidies that may be available for a generator. It should be noted that the Renewables Obligation (RO) has closed for new investments with the Contract for Difference (CfD) scheme replacing it.

3.6.1 Feed in Tariff

The Feed in Tariff (FiT) funds small-scale electricity generation, up to 5MW of capacity. Most installations to date have been solar panels, but wind and CHP also have a small market presence. The Feed in Tariff guarantees a price for all electricity exported directly on to the distribution network.

Two types of CHP are eligible for FiTs i) CHP up to 5MW where fuelled by biogas from anaerobic digestion and ii) natural gas fuelled micro-CHP installations with electrical capacity of under 2kW. These micro-CHP systems are designed primarily for domestic level CHP and at this capacity, the focus should be on self-supply as there is unlikely to be sufficient scale to justify the effort required to investigate any other route to market. At the end of 2015, 498 micro-CHP schemes were registered.

3.6.2 Renewable Heat Initiative

Heat produced from renewable combined heat and power (CHP) plants is eligible for the Renewable Heat Initiative (RHI), where the fuel or technology used is eligible for support under the scheme. Where a renewable electricity generating plant converts to heat capture to become a CHP plant, the part of the plant generating heat will be eligible to apply for accreditation provided it meets all the other eligibility criteria of the scheme.

Participants will receive payments over 20 years, based on the amount of heat generated.

The applicable fuels are:

- Solid biomass, with a capacity of at least 200kW
- Energy from waste (EfW) is eligible for RHI support under the biomass tariff where installations are first commissioned on or after 15 July 2009.
- Biogas
- Geothermal energy

The RHI supports energy from waste where not more than 90% of the waste is, or is derived from, fossil fuel (i.e. waste has a biomass content of at least 10%). Participants will receive support only on the biomass proportion of their waste and will therefore have to demonstrate what proportion of the waste is biomass. Generation of heat from the combustion of biogas in boilers or engines is eligible for the RHI.

The RHI is open to new entrants until 31 March 2021 (although the tariffs are subject to reduction between now and then depending on take-up).

3.6.3 Renewables Obligation

The Renewables Obligation (RO) is a requirement on electricity suppliers that was introduced in 2002 to incentivise investment in renewable generation. Eligible generators, once accredited by Ofgem, receive Renewables Obligation Certificates (ROCs) that are sold to suppliers as one means of showing they have met their annual RO. The number of ROCs issued per MWh of generation depends on the generation technology and commissioning date.

The table below shows the number of ROCs that are currently achievable for a CHP plant. These figures were typically adjusted yearly as government policy changes and technology developments. Higher levels of support were offered for innovative technologies, declining as the technology became more established. The scheme is closed to new generation from 31 March 2017.

Figure 6: Breakdown of the CHP fuels eligible and the number of certificates issued:

Fuel	2016-17 support (ROC/MWh)
Co-firing (low-range) with CHP*	1
Co-firing (mid-range) with CHP*	1.1
Co-firing (high-range) with CHP*	1.4
Co-firing of regular bioliquid with CHP	1
Co-firing of relevant energy crops (low-range) with CHP	1.5
Dedicated biomass with CHP	1.8
Energy from waste with CHP	1
Geothermal	1.8

* Includes solid and gaseous biomass and energy crops; low-range co-firing includes under 50% biomass fuel; mid-range is 50%-85% biomass fuel and high range is 85%+ biomass fuel

ROCs have recently traded for between £41 and £43, offering a solid secondary revenue stream for installations that accredited under the RO prior to its closure. Future price levels will depend on market conditions and are likely to vary from this level.

Note that operators of CHP generation can only claim for ROCs if their technology or fuel is not eligible under RHI scheme; see above for more details. They must make a declaration under the RO specifying that they cannot get support under RHI.

3.6.4 Contracts for Difference

Contracts for difference (CfDs) were introduced in 2015 to replace the RO with a system to support low carbon generation, offering more certainty to investors and a built-in limit to costs.

A CfD results in a payment to the generator if the strike price (a pre-set price reflecting the costs of generating using low-carbon technology) is higher than the reference price (a measure of the average wholesale price of electricity in the GB market). The generator's income is 'topped-up' to the strike price. In the event that the reference price exceeds the strike price, the generator will pay back the difference.

CfDs are now issued via an auction process. Applications are assessed and all qualified applications entered into the auction; the best value for money bids are awarded contracts. The applicable fuels for CHP are:

- Biogas (anaerobic digestion, sewerage gas, landfill gas, syngas from biological material)
- Liquid biofuels, tallow, used cooking oil
- Energy from waste
- Biomass: wood, energy crops, agricultural residue (e.g. straw)

Other technologies than CHP are also in competition for CfDs. The second CfD auction, held in April 2017 for projects to be delivered in 2021-22 or 2022-23, offered support to:

- Offshore wind
- Advanced conversion technologies (with or without CHP): i.e. synthetic gas manufactured from coal

- Anaerobic digestion (with or without CHP) above 5MW
- Dedicated biomass with CHP
- Wave and tidal
- Geothermal (with or without CHP)

Note that operators of CHP generation can apply for a CfD if their technology or fuel is not eligible under RHI scheme; see above for more details.

3.6.5 The Capacity Market

The capacity market is a government policy to insure against the possibility of blackouts caused by insufficient generation capacity at peak times. Total transmission connected capacity has been steadily falling in recent years, from just under 80GW in 2011 to around 62GW in 2016.

To encourage investment in new plant the capacity market makes payments to eligible generators for being available at times of system stress. Capacity Market contract holders receive a regular monthly revenue stream irrespective of whether they are generating and exporting electricity or not. Any generator receiving payments must be available to deliver the contracted capacity following a notice issued by the System Operator.

Contracts are awarded following an auction run by National Grid. A number of auctions may be held in each year. The main auction is to procure capacity commencing four years ahead of the year in which the auction takes place. This is referred to as the T-4 auction. If additional capacity is needed in the short term, a further auction may be held for capacity in the upcoming year and this is referred to as the T-1 auction. This may be because the forecast level of demand may have changed, some power stations have unexpectedly closed or capacity that was anticipated to be built has failed to complete.

The auction works on a “descending clock” basis, wherein the auction begins at the highest price the auctioneer, National Grid, is willing to pay and descends, with generators dropping out when the price reaches an unviable level. When the level of capacity left matches National Grid’s requirement, the auction clears and remaining generators are all paid at that rate.

Capacity market contracts can run for one year (existing plant), three years (refurbished plant) or 15 years (new-build plant). Generators will receive monthly payments of varying amounts—higher over the winter, lower over the summer—for their cleared capacity.

In the most recent 2016 T-4 auction, 544MW of existing distribution-connected CHP and 1,315MW of transmission-connected CHP cleared, as well as an additional 3.6MW of new-build. This plant will receive capacity market contracts at the clearing price of £22.50/kW. Where a plant is a new build, the support provided by the capacity market will apply for a 15-year period, which provides certainty of income for investors. However, once a capacity market contract has been awarded, if the plant is not built and therefore the capacity is not delivered, a penalty will apply. Over 99% of the CHP capacity that entered the 2016 T-4 auction cleared; a very high rate of success. Given that total capacity procured in the auction was 50,000MW, CHP has a relatively small market share at present.

Generators receiving subsidies from the FiT, RO, RHI, or CfD are not eligible for the capacity market. Note that capacity market payments are made for simply being available – any electricity actually delivered will still be paid for under the usual arrangements.

3.6.6 Summary

There is several potential subsidies available for CHP with eligibility dependent on criteria set out above. The table below summarises the eligibility of a CHP to receive each subsidy based on the fuel type:

Figure 7: Summary table of available subsidies for CHP[20]:

Fuelling	FiT[21]	RO	RHI	CfD	Capacity Market
Gas	✓	X	X	X	✓
Oil [22]	X	X	X	X	✓
Biogas	✓ [23]	✓ [24]	✓	✓	✓
Biomass	X	✓ [12]	✓	✓	✓
Energy from Waste	X	✓ [12]	✓	✓	✓
Geothermal	X	✓	✓	✓	✓

3.7 Stakeholder analysis

3.7.1 Who owns CHP plant?

Most CHP capacity in the UK—around 85%—is deployed in the industrial sector. The abundance of waste heat and fuels based on waste products make CHP plant extremely beneficial in this sector; oil refineries and chemical production alone account for half of all UK CHP. In many cases, the industrial sector uses the waste heat within the same site and does not utilise all the available heat. Where this occurs, there is potential for this heat to be captured via heat networks and distributed to other consumers of heat in the locality to the benefit of all stakeholders.

Outside the industrial sector, the largest number of schemes is in the leisure sector; swimming pools in particular are major users, although modern designs of swimming pools is reducing demand in this sector. However, the highest capacity is in the health sector mostly in hospitals, covering around a third of electrical generation and half of heat capacity.

Several local authorities operate CHPs to run district heating projects; Sheffield has the largest in the country, supplying heat to over 140 buildings—including city landmarks, the hospital, university and town halls—in addition to 2,800 homes. The scheme runs on energy-from-waste.

Major individual CHP systems include the Shard in London, where gas turbines produce 1.1MW of electricity and 1.2MW of heat, at 85.3% total efficiency. This has reduced carbon emissions for the building and provided significant cost savings versus the separate purchase of electricity and gas from the public network[25].

3.7.2 Who are the relevant stakeholders?

The principle stakeholder is the entity for whom the CHP plant is being installed. Typically, this will be an industrial or commercial company, hospital, university, or local authority, who will own and operate the scheme.

[20] See also 9.1.3 Revenue stacking
[21] Micro CHP of 2 kWe or less has a specific FiT – usually natural gas but any fuel is eligible
[22] Can reclaim Hydrocarbon Oil Duty for oil used to generate electricity, if meeting 20% electricity efficiency
[23] Specifically only anaerobic digestion biogas, not sewage gas or landfill gas
[24] Varying level of support depending on fuel mix
[25] Ref: Clarke Energy who installed and maintain the facility (https://www.clarke-energy.com/2012/the-shard-combined-heat-and-power-plant/)

However, some existing plant has been installed at no up-front cost through an agreement with a third party to buy the electricity and heat generated. This increases the unit cost of the electricity and heat, but avoids the up-front costs of the installation and is the typical business model adopted for larger scale industrial plants. Variations from this model also exist, where a proportion of the upfront costs are recovered by the installer who in return receives a percentage of the electricity benefits and maintains the asset. This benefit share minimises the engine down time by incentivising attendance should the CHP fail to operate

The users of heat networks also have a stake in the project. Meters may be used to monitor the amount of heat consumers are using and charge them appropriately. Additionally, potential users in the area may wish to join the project if it offers cost savings and environmental benefits against their Business as Usual (BAU), giving scope for growth over time.

Electricity generated in excess of the owner's needs will need to be exported and sold. This may be directly to other sites over a private wire or exported onto the distribution or transmission network. Where export is over a public network, an electricity supplier is required. Consequently, electricity suppliers, the local DNO and possibly the transmission network owner may all be relevant stakeholders. Electricity network owners are primarily interested in understanding the impact of new flows across their network to best manage reinforcement and constraints. In addition, local electricity consumers, whether connected via a private wire or across the DNOs network, have a stake in the project for security of supply, cost and environmental reasons.

Where a CHP applies for government subsidies or the capacity market, various governmental and other bodies will become stakeholders. The Feed-in-Tariff, renewables obligation, and renewable heat incentive are managed by Ofgem's environmental program, E-Serve.

Contracts for Difference are commercial relationships with the Low Carbon Contracts Company (LCCC), a government-owned company. Application for CfDs is via the LCCC but will require establishing relationships with BEIS, National Grid and Ofgem. The settlement of these contracts which involves the assessment of generation and arrangements for payment is through the Electricity Market Reform (EMR) Settlement Company.

The capacity market is run by National Grid; pre-qualification and the auction itself will be carried out by National Grid. Settlement and payment will be carried out by the Electricity Settlements Company.

Finally, local authorities will need to consider whether their investment is producing best value for money for their rate-payers.

3.8 The drive for flexibility

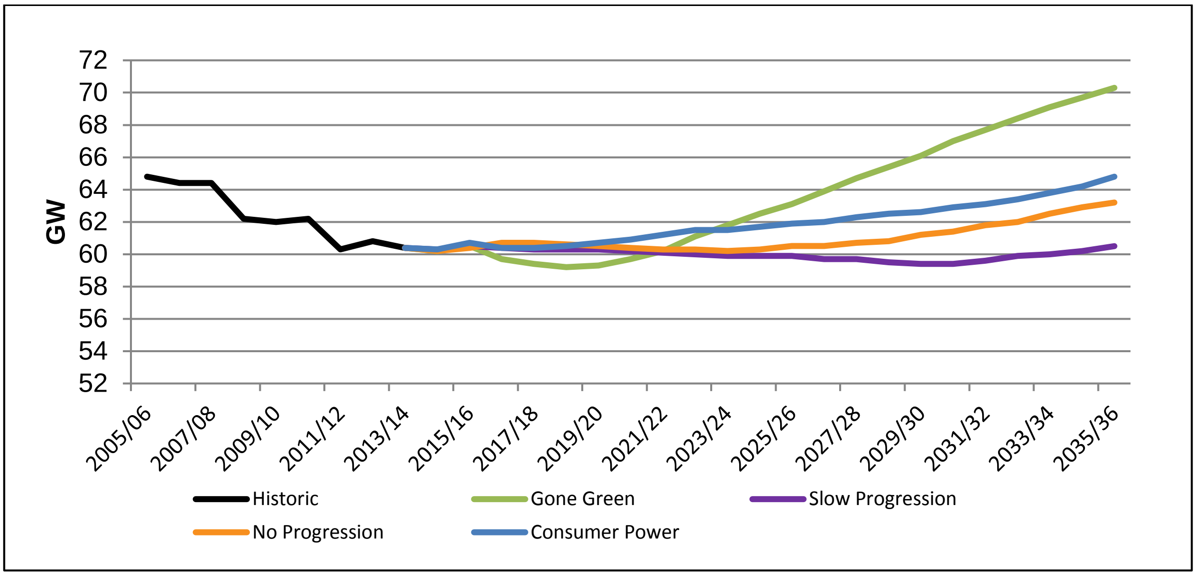
There is widespread recognition that the GB electricity system needs to be operated more flexibly to better accommodate existing and new distributed generation, higher levels of intermittent generation, the nascent storage sector, and to maximise the benefits of the roll out of smart meters.

Ofgem issued a call for evidence[26] in November 2016 on how the electricity industry can become more flexible and capture the benefits of emerging technologies. This will enable the system to be managed more optimally with demand and generation working together to minimise investment in new infrastructure.

One of the drivers behind the call for evidence is a recognition that demand is likely to increase as GB moves to a low carbon economy due to the take up of electric vehicles, heat pumps and electrification of heating load. National Grid has developed four scenarios of future demand to help assess the range of demand and the potential implications for GB electricity infrastructure requirements. The peak demand under each scenario is shown in Figure 8:

Figure 8: Peak demand under the National Grid future energy scenarios[27]

[26] https://www.ofgem.gov.uk/publications-and-updates/smart-flexible-energy-system-call-evidence
[27] More information on the Future Energy Scenarios are available on National Grid's website: http://fes.nationalgrid.com/

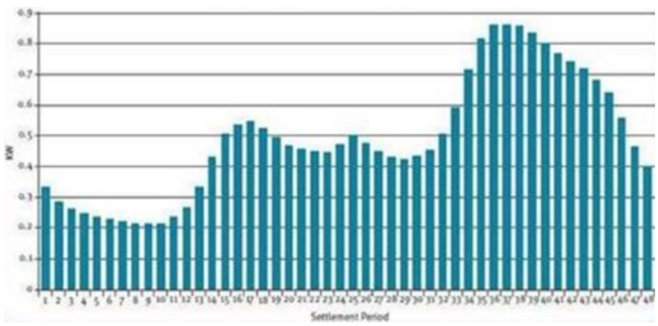


If peak demand increases in line with the Gone Green scenario it will lead to a substantial increase in network and system balancing costs. These costs can potentially be offset through the procurement of flexible services that enable peak demand to be managed. This may be through more embedded generation locating close to demand, demand side response or electrical storage options.

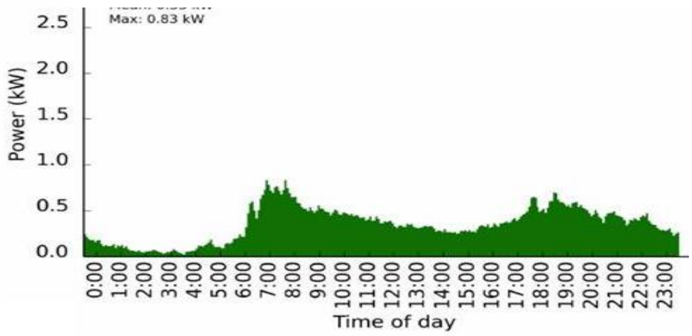
The emerging requirement for flexibility services is an opportunity for a number of players in the market and embedded generation that is able to provide flexible services is already able to benefit (and likely to be able to benefit further). Chapter 9 looks at additional revenue sources that may be available to embedded generators that are also providing heat, including the provision of ancillary services and demand side response.

CHP allows for the provision of heat and electricity to be linked together and creates flexibility for the service provider to optimise between the provision of heat and power in the most economic way. The graphs to the right show a typical electricity and heat profile for a domestic customer and the degree to which the shapes generally follow each other. The profile is similar which demonstrates the benefit of a CHP plant providing both services simultaneously. However, for a CHP plant where flexibility exists, an additional option emerges from separating out the provision of the electricity and heat services and offering additional services to the system operator where this is beneficial.

Typical Daily Electricity Demand Profile (domestic)



Typical Daily Heat Demand Profile (domestic)



4 Routes to market for a CHP

What is covered in this chapter?

This chapter describes the routes to market for the electrical output from a district heating scheme where CHP is installed. This includes a comparison of the routes to market and where they are most likely to be used. This chapter also introduces the differences between the options from a commercial and regulatory perspective, both of which are covered in detail in the subsequent chapters; Chapter 6 (regulatory considerations) and Chapter 7 (commercial considerations). The following topics are covered in this chapter:

- A description of the potential routes to market for the electrical output from a CHP
- A comparative study of the route to market options
- The contractual agreements that are required between parties
- The factors to be taken into consideration when selecting a route to market

4.1 Background

When developing a heat network project, a full evaluation is required of the different technologies that may be used to provide the heat. The evaluation should consider the objectives of the organisation undertaking the scheme and the needs and requirements of other stakeholders.

Where CHP is being considered, it is important to identify the routes to market for the electrical output, which should be considered from a commercial perspective, regulatory perspective and the degree to which they fulfil the objectives of the various stakeholders so that a preferred route can be selected.

4.2 Routes to market: Options available

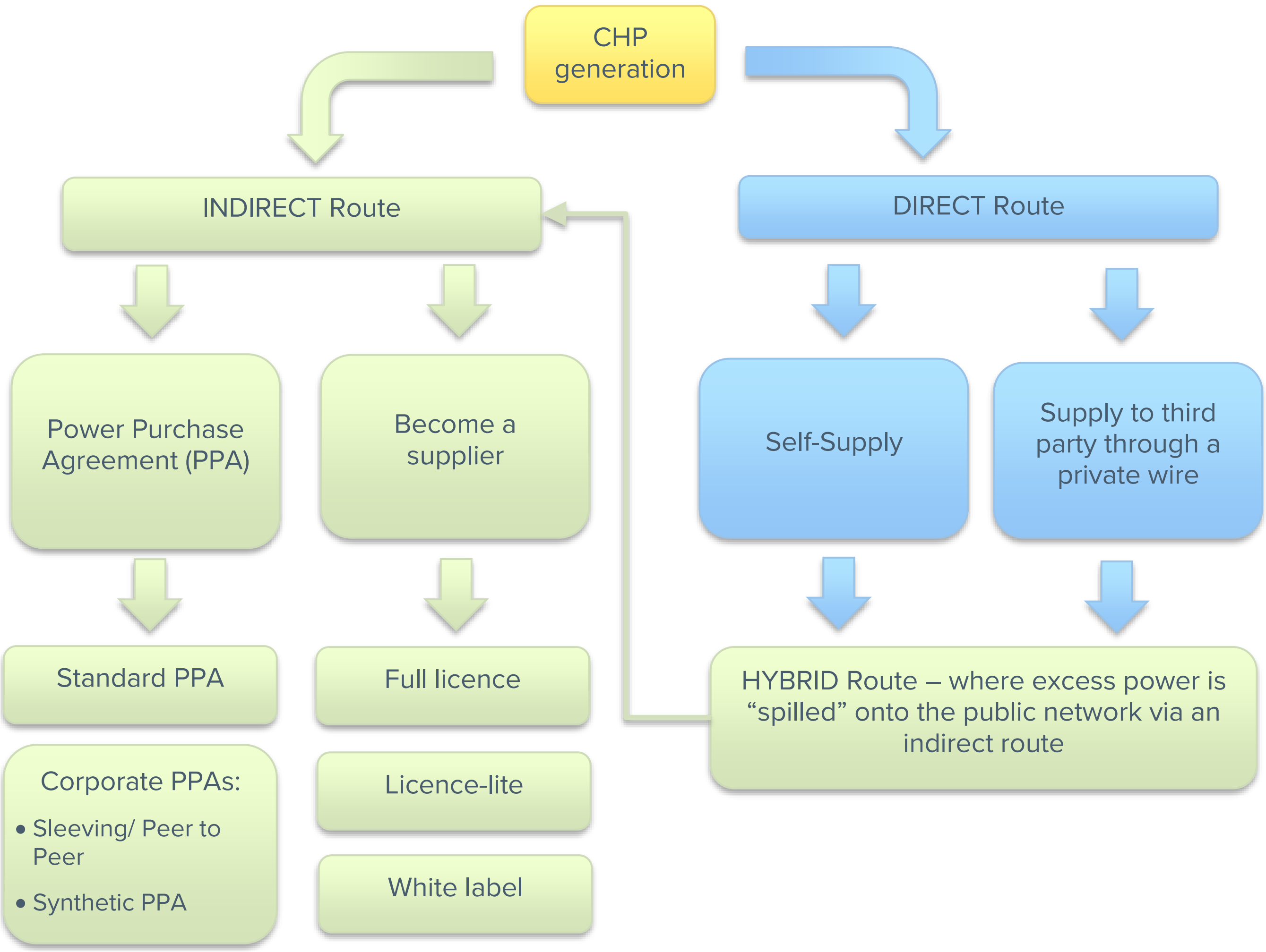
As outlined in the executive summary, these guidance notes identify eight distinct routes to market for the electrical output from a district heating scheme that can be split into two primary categories of DIRECT and INDIRECT which are defined as follows:

- DIRECT – Under a direct route to market, power is sold direct to customers or used on the same site as it is generated. The power never enters the public network.
- INDIRECT – Under an indirect route to market, power is sold onto the public network. This means that the units exported enter the national settlements systems and the units need to be allocated to an electricity supplier.

The distinction of whether power is exported via a direct or indirect route is important. A direct route avoids a number of costs because it does not use the public network or involve a licensed supplier.

The eight routes to markets considered within these guidance notes fall within the direct or indirect route to market. The diagram below illustrates the range of options available and how they are categorised:

Figure 9: CHP potential routes to market



4.2.1 Direct route to market: Outside national settlement

Under a direct route to market the electrical output from a CHP is used to supply a customer that is directly connected to the CHP on site or via a private wire. The power can be either used by the same owner of the CHP (referred to as **self-supply**), or sold to a third party (referred to as **private wire, see case study opposite for an example**). Under either solution, the power from the CHP does not enter the public distribution network that is owned by the Distribution Network Operator (DNO) and supply is made under a licence exemption and so avoids the charges associated with the national settlement system.

In most cases, the demand customer will maintain a connection to the public network to enable security of supply for when the generator is unavailable. The generator may also maintain a connection point with the public network either through the demand customer or independently to enable them to export excess power. In some cases either the generator or customer will own the private network and one party may rely on the other for access to the public network. This is explained in more detail in 4.4.3.

Private wire and domestic customers

The Gascoigne Estate District Energy Scheme originally planned to sell their power onto the public network using a standard PPA arrangement. Once other routes to market were fully assessed, it became clear that a private wire arrangement produced a much higher Internal Rate of Return for the project and lower electricity prices for end consumers. In addition, providing power to domestic customers was found to be more beneficial than selling to commercial properties and the planned scheme will supply around 1,000 properties and two schools.

The sale of electricity via a private wire is utilising the exemptions from having to hold supply and distribution licences. Legal advice was sought to ensure the exemptions were valid for the planned development.

For more details on the case studies see Appendix 1

4.2.2 Indirect route to market: Using national settlement

All electricity exported onto the distribution network enters the national settlement system. This currently requires units that enter or exit the public network to be allocated to a licensed supplier[28] (or power is given away if it is not registered). Consequently, the two options available to a distribution connected CHP that uses an indirect route to market is to agree a Power Purchase Agreement (PPA) with an electricity supplier or to become a supplier in their own right.

[28] A small number of large generators become BSC parties themselves and deal directly with the national settlement system directly rather than though a supplier. These are called Central Volume Allocation (CVA) sites. The majority contract through a supplier and are referred to as Supplier Volume Allocation (SVA) sites.

Where the generator adopts a supplier approach, three options exist. It should be noted that although becoming an electricity supplier is associated with supplying end customers, it would be possible for an organisation to become an electricity supplier with a portfolio of generators and no demand customers (with the exception of a White Label supplier). This would enable the output from the portfolio of plant to be traded on the wholesale market. A high-level description of the three supplier models are contained below and a more detailed explanation of each is contained in 4.3:

- **Full licence** – Entity becomes a fully licensed supplier and the export units are allocated to the supplier.
- **Licence lite** – Entity becomes a licensed supplier, but the licence excludes the requirements to accede to industry codes and requires the Licence Lite supplier to contract with a fully licensed supplier to provide this element of the service. The export units of the generator are allocated to the fully licensed supplier as the party that directly complies with the industry codes. The central industry systems 'flag' the meters so they can be identified as being part of the Licence Lite supplier's portfolio.
  White label – Entity partners with a licensed supplier to offer electricity tariffs, typically on a commission based agreement. The export from the generator is allocated to the licensed supplier.

Where a PPA approach is adopted there are a number of variations that may be used. A high-level description of each is contained below and a more detailed explanation of each is contained in 4.3 and the Heads of Terms in Appendix 3:

- **Standard PPA** - A standard PPA agreement allocates the export of a generator to a supplier. The supplier pays the generator for its output and a proportion of embedded benefits, but will include some allowance for the services it provides
- **Corporate PPA** – Used to describe agreements between generators and end customers, but where the electricity flows via the public network. A supplier is required to sit between the generator and end customer to implement the agreement as the supplier must register all meters and is the party exposed to network charges for moving the power from the generation asset to the consumer's meter(s). Corporate PPAs can be further split into two sub-categories:
  - **Sleeving/ Peer to Peer** – This is where a generator agrees to supply a demand customer. The agreements are then implemented via a supplier as the party that registers the meters, pays network charges (which it will typically pass through to the counterparties), and a fee for providing the service
    - A sleeving agreement is where a bilateral deal is struck between the generator and end customer to agree a value for the power and taken to the supplier for implementation.
    - A Peer to Peer agreement is implemented in a similar way, but the generator contracts with end customers through a Peer to Peer platform that matches generation and demand customers..
  - **Synthetic PPA** – A Synthetic PPA is an agreement between a generator and end customer that hedges the wholesale price element of the electricity bill using a contract for difference approach. A PPA will still be required to allocate the generators export to a supplier within national settlements.

4.2.3 Hybrid solution

It is possible for a CHP to use a combination of direct and indirect routes to market for the export from its power station. Under this arrangement, part of the CHPs export flows direct to a customer via a private wire and part flows onto the DNOs network, thereby using the national settlement system. This may occur where there is insufficient demand to absorb the whole of the generation output, so some power will be exported (spilled) onto the distribution network.

Where an embedded generator adopts a hybrid route and plans to spill some excess power onto the public network, it will be necessary for the generator to have a connection agreement from the DNO and a PPA in place for a supplier to install and register the export meter allowing revenue to be received for the spilled power. Where these arrangements are not in place, it may be possible to export power through the import meter onto the public network, but there would be no recognition of this as the power would not be allocated to a supplier and therefore no revenue would be received. In addition to this DNOs need to know when generation is connected to their network for safety purposes and for larger connections, a Maximum Export Capacity needs to be agreed within a connection agreement. Exporting onto a public network without a connection agreement to authorise the export could drive costs for the DNO who could consider installing reverse power protection to detect any spill and trip the generator.

4.2.4 Virtual Microgrid

A virtual microgrid is where a generator sells to demand customers who are connected to the public network in a similar locality to the generator. It is called a virtual network, because the parties attempt to replicate a private wire arrangement but using the public network instead of installing their own private network.

This business model has been talked about for a number of years, but under the current GB trading arrangements all electricity that uses the public network becomes part of the national settlement processes and therefore does not recognise localised collections of generation and demand meters. In addition, all meters would still be charged for use of the DNO's network as if they were part of the wider network—i.e. users face charges based on the assumption electricity flows from the transmission system interface (the Grid Supply Point), rather than making allowance for all (or the majority) of power flows happening within the virtual microgrid. This means there is no commercial benefit from this type of arrangement, unlike a private wire arrangement.

4.2.5 Licence exempt supply over public network

Another potential route to market is to become a licence exempt supplier, but using the public network rather than a private wire to connect the generator and demand customers. This route is available to licence exempt suppliers wishing to supply less than 5MW of power (but limited to a maximum of 2.5MW to the domestic sector) over the public network or where a specific exemption is applied for and granted by the Secretary of State. This is effectively a subset of the virtual microgrid route to market.

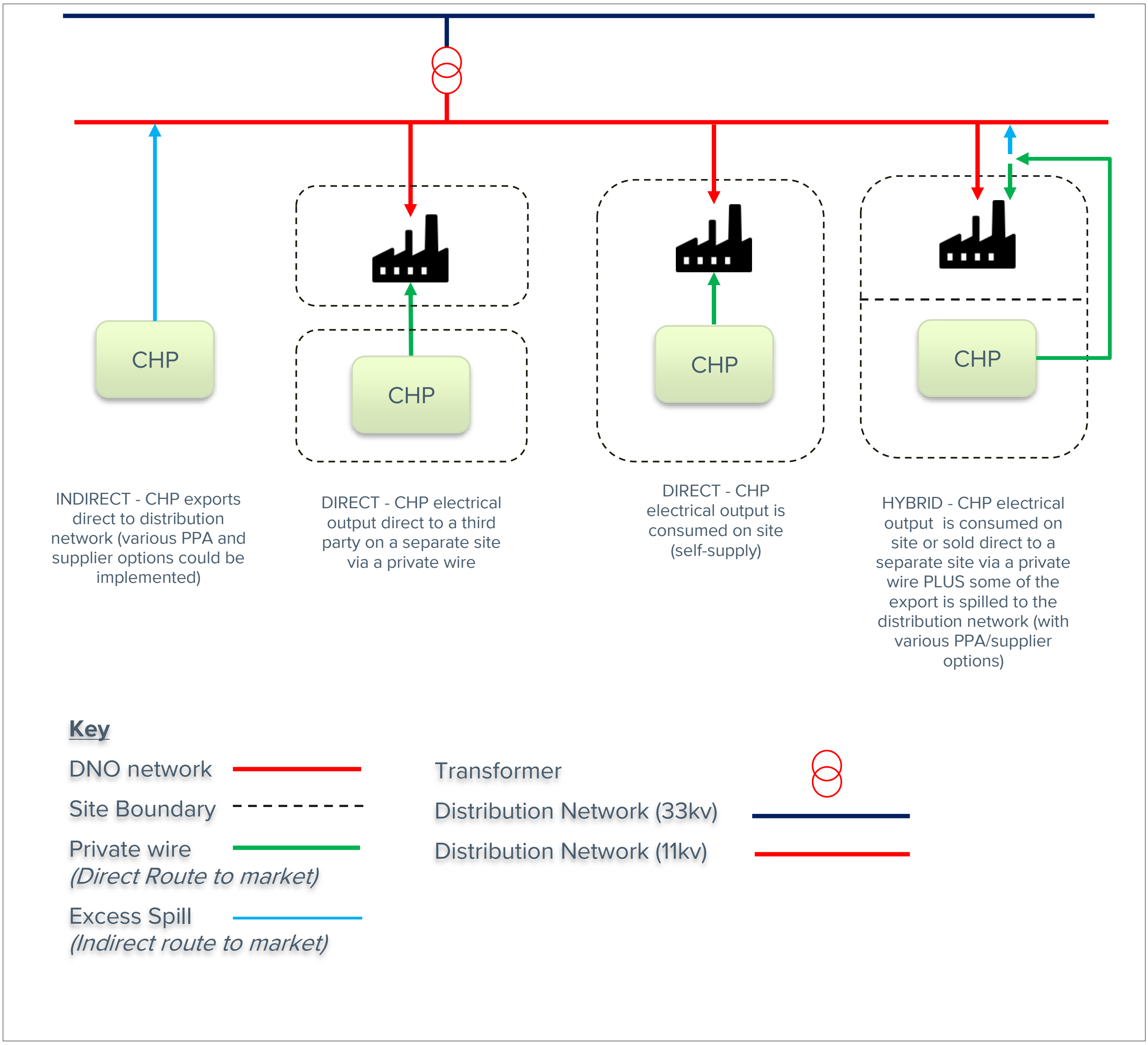
Although this route to market is theoretically feasible, in the current market structure it relies on the involvement of a third party licensed supplier as all units of electricity that flow across the public network must be accounted for by allocating them to a licensed supplier. Consequently, for a party to make use of this exemption and avoid the need for a licence they must contract with a licensed supplier. This effectively places another organisation between the supplier and the end customer which is likely to add an additional layer of cost with little benefit. An equivalent position can be achieved through a corporate PPA type of agreement.

Implementing this approach without a third party licensed supplier requires a new specific exemption (see 6.2.7) or changes to class exemptions *and/or* changes to other aspects of the electricity market, therefore this type of supply is not considered further within these guidance notes.

4.2.6 Summary of Routes to Market

A diagrammatic representation of the difference between using a direct and indirect route to market is shown below:

Figure 10: Direct and indirect routes to market



4.3 Route to market descriptions

The following pages contain a one page summary for each of the possible routes to market that a CHP could adopt for their export. In each case, more detail on each is available in the appendix and can be accessed by clicking on the icon at the bottom of each route to market page.

The table below shows the routes to market that are covered. They can be accessed directly from this table by clicking on the title.

Figure 11: Route to market options for a CHP

Category	Route to Market
Non-settlement route	Self-supply
	Direct supply over private wire
Becoming a supplier	Full Licence
	Licence-Lite
	White Label
Power Purchase Agreement (PPA)	Sleeving/ Peer to Peer
	Synthetic PPA
	Standard PPA

Additonal detail on each route is available in Appendix 2 – Detailed description of Routes to Market

ROUTE TO MARKET FOR CHP EXPORT – SELF-SUPPLY

Product Description:

A self-supply route to market is where the export from a CHP is used to offset consumption on the same site or a site that is connected by a private wire but owned by the same entity. By directly offsetting consumption and therefore reducing the site consumption at the import meter it avoids the costs associated with consumption.

As the cost of importing power tend to be larger than the price received for exporting power, this can be an attractive option from a commercial perspective, although the economics of building an on-site power station needs to be assessed on a site by site basis. Where the export is larger than the on-site consumption, the generator can spill onto the distribution network and a PPA will be required with a supplier to capture the value of any spill.

Key Features:

- The value of the electrical output consumed on site can be assessed based on the offset site import charges.
- The generator is not necessarily registered with a supplier e.g. if the electrical output is fully consumed on site to offset metered import. Where any excess export spills onto the distribution network the generator will need to register their export with a supplier and agree a PPA in order to generate an income.
- Avoids use of the national settlement system and local distribution system.
- Output does not have to travel long distances, minimising system losses.
- The consumption profile of the demand customer will change due to the on-site generator which may impact on their contract to procure electricity from an electricity supplier
- On-site generation will need to register with the local DNO even if not exporting.

Relevance to CHP:

- The CHP electrical output can be used on site which extracts the maximum value for the power.
- A low carbon solution as the power is generated and delivered to on-site users.
- Site still needs to retain and pay for connection to the distribution network and supply contract for when the CHP is unavailable.

Examples of Self-Supply:

- Domestic properties with solar
- Hotels
- Hospitals
- Oil refineries and chemical production plants

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – DIRECT SUPPLY OVER PRIVATE WIRE

Product Description:

A direct supply over a private wire is where a generator supplies power to a third party through a private wire and does not use the distribution network. This may be a supply to one or many premises. There will be a contractual relationship between the generator and the third party that specifies the price paid for the power. This type of arrangement has become increasingly commonplace as the generation export offsets the site import for the third party and the potential value of the generation can therefore be judged against the import costs of the third party.

The additional value generated under this type of arrangement will be split between the generator and the import site. The value of the energy sold takes into account the cost of installing and maintaining the private wire. If the generator spills any excess generation onto the distribution network a PPA with a supplier will be required to capture this additional revenue.

A private wire arrangement means that customers are (typically) being supplied with electricity without a supply or distribution licence. There are a number of class exemptions that enable this and the CHP or relevant entity will need to ensure it is compliant with the exemption criteria.

Key Features:

- A contractual relationship will need to exist between the generator and the end customer(s). This will set out the terms for the supply, including the price for the power
- The generator and customer(s) will each need to consider their access to the public network and the degree to which they have independent access
  The generator may need to qualify for a class exemption to enable it to supply power to a third party without having a supply licence and similarly for a distribution licence exemption
- Avoids use of the national settlement system and local distribution system (assuming 100% of power produced is consumed on the private wire network)
- Export does not have to travel long distances, minimising system losses.
- Reduced consumption on site may cause additional problems for the DNO if the site is connected to generation dominated part of the distribution network
- On site generation may need to register with DNO even if not exporting
- May impact on the pre-existing import supply arrangements as import profile will differ.
- Customers on the private wire have a right to use an independent supplier to source their electricity

Relevance to CHP:

- Enables a CHP to sell its output locally without using the distribution network
- The additional value for selling direct to a customer needs to be judged against the cost of building and maintaining the private wire

Examples of Direct Supply over Private Wire:

- DP Ports & Coryton power station

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – FULL SUPPLY LICENCE

Product Description:

Adopting the full supply licence approach as a route to market involves undertaking all activities associated with gaining a full supply licence. This includes becoming a party to all relevant industry codes and establishing dataflows with the national settlement systems. It also involves complying with all licence conditions, establishing a brand, setting up tariffs and the infrastructure required to interact with customers (although this may be simplified if the supplier only serves customers under the same control or if activity is limited to trading in the wholesale market).

Setting up a full supply business can be a large undertaking, but it is possible to outsource various parts of the business as long as the supplier ensures it remains compliant with its licence conditions. There is also the possibility of buying a pre-accredited supply company solution where a specialist utility IT systems vendor gains an electricity supply licence and accedes to a number of the core industry codes. This prequalified licensed company is then sold onto the new entrant and the new company can go through Controlled Market Entry which represents the final stage of accreditation.

Key Features:

- Upfront/ ongoing expenditure is required to comply with central systems and national codes.
- A supply licence approach can be adopted without demand customers by contracting with embedded generators and selling their export directly into the wholesale market.
- Where end customers form part of the business model, investment in infrastructure and staff are required to manage the relationship with customers.
- Generator and customer meters are registered by the supplier and their units allocated to the supplier.
- Supply is a high volume, low margin business that requires a large number of customers to cover the fixed costs of running the business.
- Supplier needs to manage risks associated with imbalance and credit risks (both potentially reduced if serving only customers under the same control), wholesale and retail market risk over different time periods to maximise their return.
- Supplier still retains the option to contract out parts of the business model as long as they remain compliant with their licence. (e.g. outsourcing a billing function)

Relevance to CHP:

- A CHP will still need a PPA agreement with the licensed supplier.
- The fully licensed supplier will have full flexibility on the contractual relationship with the CHP including how benefits are split between the generator, the supply business and the end customer. This is likely to depend on the strategic objectives of the supplier (although generator, customer, supplier could be vertically integrated).

Examples of Full Licence Supply:

- Big Six suppliers
- Haven Power – focus on industrial & commercial
- Electroroute

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – LICENCE LITE SUPPLY

Product Description:

A Licence Lite approach enables a company to become an electricity supplier while excluding them from signing up to the core industry codes. The Licence Lite approach requires the company (junior supplier) to contract with a fully licensed supplier (senior supplier) to interact with the industry codes on their behalf.

The Licence Lite arrangement allows the junior supplier to avoid the need to procure the IT systems required to interface with the national settlement systems and the staff to achieve complex code compliance. The junior supplier undertakes the customer facing activity, but it is the senior supplier (as signatory to the codes) that registers meters and notifies wholesale contracts for the junior supplier. Imbalance and network charges are paid in the first instance by the senior supplier, which then flow back to the junior supplier. The licence-lite supplier can procure power from the wholesale market or direct from an embedded generator such as a CHP, but will need contractual arrangements to allow the senior supplier to settle the volumes.

Key Features:

- A licence lite approach enables an entity to have a direct contractual relationship with customers for the sale of embedded generation.
- The Senior supplier provides the necessary central industry interface processes on the junior supplier's behalf.
- Junior supplier needs a contractual arrangement with a licensed supplier to provide interactions with industry codes.
- Junior supplier will retain supply licence obligations outside the area of industry codes.
- Although not directly exposed to imbalance and network charges these are passed through by the Senior supplier and must be managed
- Junior supplier can construct their own range of tariffs and pricing strategy.
- Junior supplier will require IT infrastructure to manage the relationship with the customer.
- Lower set-up costs compared to fully licensed (but unproven market for provision of these services).
- The Junior supplier will typically require access to wholesale markets to meet customer demand/sell excess power

Relevance to CHP:

- A CHP will still need a PPA agreement with the Junior supplier to register their export.
- The Junior supplier will have full flexibility on the contractual relationship with the CHP including how benefits are split between the generator, the supply business and the end customer. This is likely to depend on the strategic objectives of the supplier (although generator, customer, supplier could be vertically integrated).
- CHP electrical output is unlikely to match customer demand at all times.

Examples of Licence Lite Supply:

- GLA – proposing to set up as licence lite

No Licence Lite suppliers exist at date of publication

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – WHITE LABEL SUPPLY PARTNERSHIP

Product Description:

A White Label Supplier is an unlicensed company that has a contractual agreement with a licensed supplier to sell electricity to consumers using the white label's brand. The white label supplier will need an agreement with a fully licensed supplier to provide services on their behalf which typically cover all the regulatory interaction with industry codes, billing of customers and customer service functions. The white label electricity supply business can provide a range of customised tariffs sold under a unique brand while the licensed supplier use their existing systems and infrastructure to manage the electricity supply to the end customer (which could be under the same control as the CHP generator).

The split of supply functions between the fully licensed supplier and the white label supplier will depend on the contract between the two. Most licensed suppliers will want to undertake the majority of business functions to ensure the white label activity does not result in licence breaches. The white label will seek to have the value of the CHP export reflected in local tariffs, with appropriate value for the CHP for it to be an attractive option to retail customers.

Key Features:

- Allows a company to establish customised electricity tariffs with a separate brand without a large investment in infrastructure.
- Contractual arrangement will exist between the licensed supplier and white label supplier that specifies the services provided by each. These arrangements tend to be bespoke at present.
- The contract will typically require the white label supplier to indemnify the licensed supplier against any regulatory non-compliance that results from their actions.
- The white label supplier typically earns a commission for each customer acquired and possibly a retention fee if the customer remains when the contract expires, although new models are emerging that provide monthly payments based on a share of tariff margin.
- Customers and generators are registered against the licensed supplier NOT the white label supplier.
- Licensed supplier will provide top-up power and dispose of excess power so likely to have PPAs with other generation or to make arrangements to buy/sell power in the wholesale market

Relevance to CHP:

- A CHP will still need a PPA agreement with a licensed supplier. To derive benefit to white label customers this would be with the licensed supplier who is contracted with the white label supplier.
- A CHP may choose this route to market as the CHP could be used as a unique selling point to market the power to local customers i.e. heat and power from same supplier

Examples of White Label Supply:

- Marks & Spencer
- White Rose – backed by Leeds City Council
- Sainsbury
- Ebico – Targeting reducing fuel poverty
- Glide – Targeting supply to students

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – SLEEVING/ PEER TO PEER

Product Description:

A sleeved or peer to peer supply is where a generator forms an agreement with a demand customer to supply them with electricity over the distribution network. To enable this agreement, a supplier is used as a facilitator by arranging and paying for the transport of that energy across the public grid and managing the risk of a supply and demand mismatch or 'imbalance'.

Sleeving allows a generator to approach demand customers and agree terms that suit both parties. This type of agreement can be between a generator and either one or several demand customers and allows for longer term offtakes to be agreed which creates certainty for both parties.

A peer-to-peer supply is implemented in the same way as a sleeved agreement, but the matching of demand and generation takes place via a peer to peer platform.

The licensed supplier registers all meters in the arrangement and will typically flow network charges through to the parties involved. It will also levy a charge for providing the service.

Key Features:

- A generator needs to find end customers willing to adopt this approach or use a supplier who is able to source customers who are looking for this type of agreement (this may be simplified for LAs who are likely to have suitable consumption to match generation).
- Generator will need to agree a PPA with the supplier. The terms of this PPA are likely to reflect the type of agreement made with the demand customers
- The demand customer is typically located near to the generator. However, there is no commercial advantage from agreeing a deal between a generator and demand customer that are located close to one another, but the advantages are significantly reduced where the generator and customers are not located in the same DNO network area
- Payments from the demand customer to generator would typically be made via the supplier
- Unlike some private wire arrangements, the generator is not fully reliant on the end customer for its export and has access to the public distribution network.
- The export and the import will not match in each half hour and the agreement will need to specify how the cost of the top-up and spill is determined and allocated between parties.

Relevance to CHP:

- Enables a CHP to negotiate agreements for their export over longer durations than are typically available in the market.
- Enables a CHP to sell their output to local demand customers without the need to become a supplier or invest in private wire.
- Allows the CHP to provide both electricity and heat to the same customer
- Some customers want to demonstrate 'green' supply for Corporate social responsibility (CSR) purposes and may be prepared to pay a premium

Examples of Sleeving/ Peer-to-Peer:

- National Trust have sleeved a number of sites
- Innovate UK SWELL project

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – SYNTHETIC PPA

Product Description:

A synthetic PPA is where a generator and consumer enter into an agreement for the price of power sold by the generator and bought by the consumer. However, a synthetic PPA is a purely financial arrangement which sits entirely separate from the generator's PPA under which it sells actual power and the consumer's supply agreement under which it buys actual power. The synthetic PPA is typically a contract for difference, where payment adjustments can be made in either direction (between the generator and consumer) as the actual commodity price of power fluctuates. This can deliver greater price certainty to generator and consumer.

Key Features:

- Requires generator to have a standard PPA with a supplier to enable the export to enter the national settlement system.
- Generator negotiates a bilateral contract directly with one or more end customers. This typically is a CfD arrangement.
- The generator and consumer can be registered to different suppliers
- The CfD will require a reference price for the settlement of the contract. The reference price will form part of the negotiation, but would typically be based on the underlying wholesale market price as published by an exchange. Alternatively, it could include some elements of embedded benefits such as Triad.
- CfD would normally extend to a number of years, enabling both the generator and end customer stability of revenues/ costs
- Some basis risk is likely to exist for both parties as the CfD reference price will not exactly match the revenue stream in the case of the generator or the wholesale element of the end customer's bill.

Relevance to CHP:

- This is a relatively simple way for a CHP to gain security of revenue over a longer time period.
- The CHP can agree a CfD with any customer, even those located far away.
- There will be some basis risk for the CHP which will need to be assessed

Examples of Synthetic PPA:

- Marks and Spencer "Price Guarantee Agreement"

Click here for more information

ROUTE TO MARKET FOR CHP EXPORT – STANDARD POWER PURCHASE AGREMENT (PPA)

Product Description:

A PPA is an agreement between a generator and a licensed supplier. The PPA will enable the export from the generator to be allocated to the supplier under the national settlement process and therefore the supplier will become responsible for all cashflows that are attributable to the generator. These cashflows range from income from the wholesale market, embedded benefits and imbalance charges.

The PPA specifies how the supplier pays the generator for cashflows that result from the units exported by the generator. This may be a percentage of the income generated or some elements of the income may be passed straight through to the generator. The PPA may also cover details over who is responsible for despatching the plant and the notification of the planned running regime to assist the supplier in minimising their imbalance position.

Key Features:

- A competitive market exists for PPAs with suppliers competing to secure generation export.
- Standard PPAs can be agreed through the e-power monthly auction covering a range of time periods see boxout in section 4.5.2 and section 8.2.4
- PPAs can be negotiated directly between a supplier and generator. This enables non-standard arrangements to be agreed. Contract lengths can range from one to many years.
- The generator can expect to achieve a greater share of income where the generation is reliable and does not place the imbalance position of the supplier at risk.
- The PPAs can have a range of methods for agreeing wholesale price discovery and generation despatch. This can vary from the supplier taking responsibility for optimising the generation output to the generator making trading decisions and instructing the supplier to sell the output at the current market price.

Relevance to CHP:

- Unless the generator is consuming or selling all its output via a direct route (or prepared to give exported power away), a PPA will be needed with a supplier.
- The CHP will need to decide on the degree of interaction required with wholesale markets and how this is implemented
- The expected running regime may impact the type of PPA agreed
- Can be used as a holding position while developing other routes to market

Examples of PPA:

- E-power auctions standardised PPAs
- Bespoke PPAs offered by most suppliers

Click here for more information

4.4 Using a direct route to market

The choice between an indirect route and selling direct to a customer are based on a number of factors. As a general rule, a direct supply to a customer has a number of advantages over the indirect route as it allows for the full costs of importing power to be offset. Under both a self-supply and private wire arrangement, additional network assets will need to be constructed to connect the generator to the demand customers. The amount of network required is site specific but illustrative costs are provided in the following section. The economic benefits of adopting each route to market are considered in Chapter 7.

4.4.1 Electricity supply infrastructure costs

Each DNO publishes a Common Connection Charging Methodology (CCCM) statement which provides estimates of connection costs under a range of scenarios. These statements can be accessed from the DNO websites and a link to each DNO website is available on the Energy Network Association here.

The CCCM statement contains a number of worked examples that provide an estimate of costs for connecting different demand and generation customers. To provide an illustration of the costs of building a small High Voltage (HV)[29] private wire with customers connected at Low Voltage (LV)[30], example 3 from the statement is replicated below.

This example looks at the cost of connecting a LV three phase 600kVA connection to a commercial premise. The cost includes installing HV cable and a transformer to reduce the voltage to LV. Two scenarios are presented, one with 150m of HV cable and one with 300m of HV cable. The total cost in each case is shown in the table below:

Figure 12: Illustrative cost of connecting a 600kVA LV demand customer

	150m of HV cable	300m of HV cable
Provision and installation of HV cable	£30,000	£35,000
800kVA substation	£17,000	£17,000
Provision and installation LV cabling	£4,400	£4,400
Metering panel	£800	£800
HV joint to network	£1,900	£1,900
Total Extension Asset Cost	**£54,100**	**£59,100**

The cost of establishing a network will depend on the assets required and therefore the likely expenditure will vary from site to site. To provide an indication of the higher end of the range of costs, a further example from the CCCM is replicated below. This is example 8A and involves connecting a 2MVA capacity network that is sufficient to supply a housing estate with 900 properties:

Figure 13: Illustrative cost of connecting a housing estate with 900 domestic customers

[29] High Voltage at distribution covers networks ranging from 1kV up to 11kV
[30] Low Voltage at distribution covers networks below 1kV

	Illustrative Cost (£)
1200m of 11kV Cable	£120,000
3 by 800kVA distribution substations	£150,000
On site LV mains and services	£330,000
2 by 11kV closing joints	£5,000
Total Extension Asset Cost	**£605,000**

One potential cost saving for a generator that is also providing heat is to lay the electricity cables in the same trenches alongside the heat network. The cables will need to be kept a minimum distance from the heat network pipes (distance will vary depending on the size of cable and pipes) and may require slightly more excavation. However, this small incremental cost should yield savings over laying a separate electricity network (although there may be legal implications to consider e.g. if an organisation's powers to lay heat mains differs from its powers to lay cables).

Once installed, a private wire will require ongoing expenditure to maintain it. The DNOs allocate an Operations and Maintenance (O&M) cost when setting use of system charges for end customers and this can be used to determine an estimate for a private wire. The value of the O&M element within the DNO charging models is a percentage of the modern equivalent asset value of the assets in question. This is normally around 1.5% which, for the example in the table above (an asset cost of £605,000), would give a cost of around £9,075 per annum. The DNO O&M value is an average value and the actual value will vary from site to site and over time. It can be expected that a new private wire arrangement would require very little O&M expenditure in the early years of operation, but that more expenditure would be expected as the asset ages.

For both direct routes to market (self-supply and private wire) the cost of the additional network assets need to be offset against the additional revenue earned. Depending on the number of assets required, this will be a large driver of whether this route to market is economically viable. An additional consideration is the cost to finance the network assets. This is likely to be a more significant issue for a private wire arrangement as a risk exists that the customer may not be there for the life of the asset resulting in a stranded asset.

Developers may also wish to consider whether their electricity distribution activity will be of sufficient scale to allow them to approach the capital and operational costs that DNOs can achieve.

4.4.2 Self-Supply Considerations

There are two issues associated with a self-supply that should be considered before this option is adopted. Firstly, unless the connection agreement is amended, any export may not have a guaranteed right of access to the public network. This may become an issue if the on-site demand is removed at a later date, and the generator needs to export to the public network as the connection agreement will need to be amended to enable the export. This may result in additional reinforcement costs that could be material.

Secondly, the self-supply option must be considered in the context of the strategic aims of the owner company (normally the local authority). Where the funding for the CHP has been justified and approved to meet a certain objective, then this will impact on the route to market selected. For example, where a CHP has been constructed as part of a community project and the local authority wants the export to benefit the local community through lower bills for domestic customers, then the export needs to be allocated to those customers. This would effectively rule out a self-supply route, but allow for a private wire arrangement or an indirect route to market.

4.4.3 Private Wire Considerations

Where a generator connects directly to a third party over a private wire, the benefits are similar to that of a self-supply arrangement as the cost savings equate to the reduced import charge for the third party. However, the savings that accrue to the generator will be less as the third party will be likely to require a share of the savings to induce them to enter into the agreement.

The commercial case for direct supply over a private wire is largely dependent on the distance between the generation and demand and the ease of laying a private wire. There may be physical barriers such as railway lines or a watercourse or commercial barriers such as right of access issues. In addition, the right of access to the public network issue is more complex when a third party is involved. There are several ways in which the private network can be organised to allow the generator to supply electricity to both the customer and gain access to the public network. In some cases, the electricity is supplied directly to the customer and access to the public network is only via the assets on the customer's site. This is a risky undertaking as the generator is reliant on access to the customer assets to enable their route to the public network. Metering arrangements may have to change to accommodate this approach.

A more common arrangement is to connect the generator into the sole use assets that connect the customer into the public network. This means that the power will automatically flow to the customer when the demand exists, but the generator also has a direct connection to the public network. When determining the network configuration to connect the generator, consideration must also be given to the connection of the demand customer and the implications for their pre-existing connection agreement.

A private wire approach

The Gateshead Energy Centre selected a private wire route to market as it increased the electricity revenues received under the project. They initially looked at sleeving as a cheaper way of capturing the higher revenues, but realised that this only applied to the wholesale price, whereas a private wire approach allowed the project to capture the higher retail price. Any excess electricity is exported to the public network and sold via a PPA.

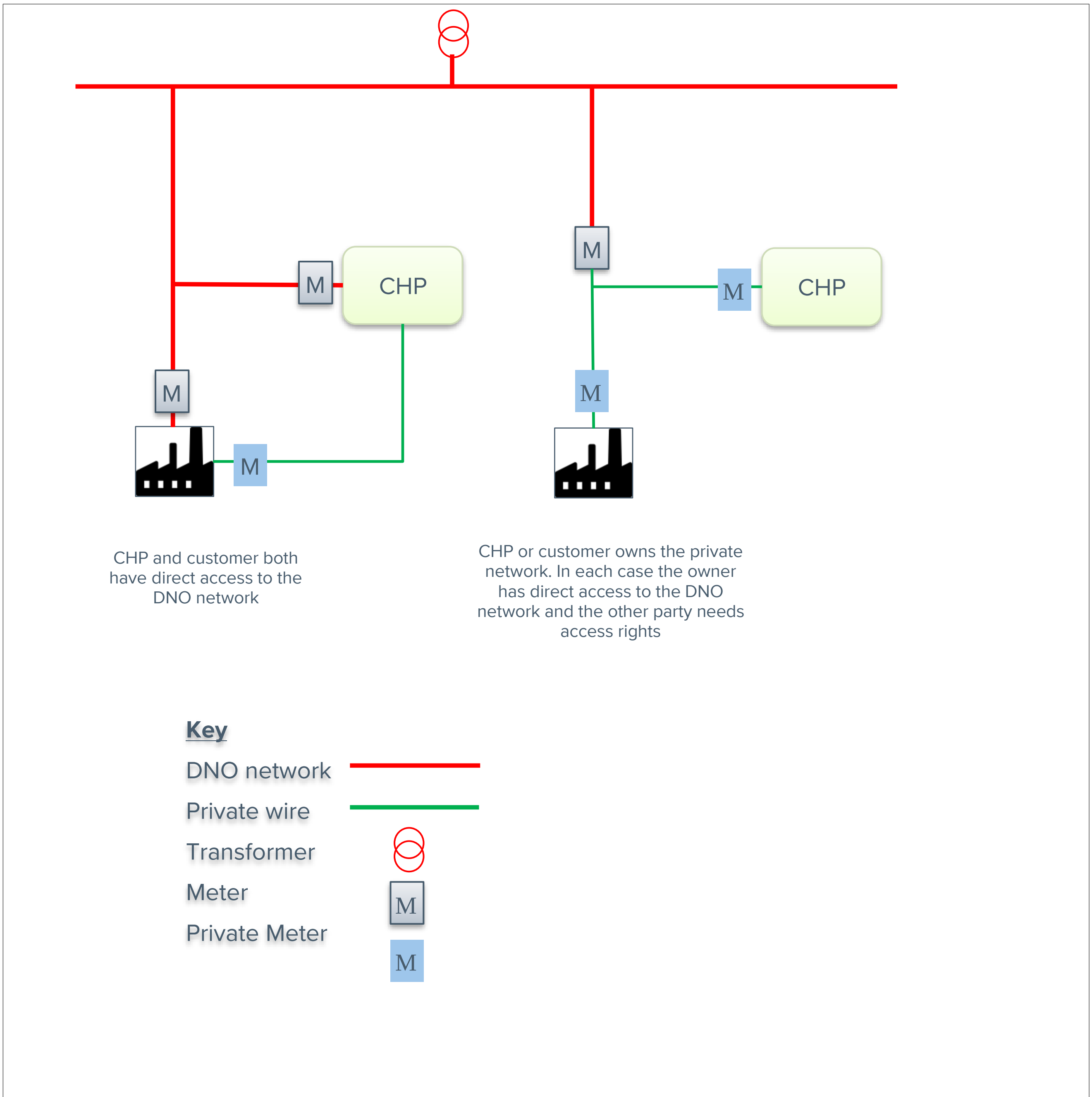
The scheme is managed under an exemption from holding an electricity supply and distribution licence, so that power can be sold directly to public and commercial customers without the requirement for a license.

For more details on the case studies see Appendix 1

The diagram below demonstrates the options available to the generator and customer to enable them both to have access to the public network or where one party requires access rights from the owner of the private wire. These configurations are consistent with the hybrid route to market illustrated in figure 10[31]:

[31] Note Option 1 in Figure 14 requires switchgear (not shown for simplicity) to change CHP output from supplying over private wire to exporting to grid

Figure 14: Example connections for embedded plant under private wire arrangements



A further consideration when adopting a private wire approach is whether this is possible from a legal and regulatory perspective. Supplying a customer with electricity without a supply licence requires the company to be exempt from the requirement to hold a supply licence. In addition, where the supplier is a local authority, further constraints may also apply. This is a complex area and is covered in detail in Chapter 6.

4.5 Using an indirect route to market

A generator has several possible routes to market via the public network if self-supply and private wire supply are not available or are not viable. All of the indirect routes require a connection agreement that creates a right of access for a fixed amount of export and import capacity. It should be noted that establishing firm access rights through a connection agreement can result in substantial reinforcement costs. In many cases, embedded generators are currently connecting using a “managed connection” (see section 7.9) which requires lower reinforcement costs and enables a generator to connect in shorter timescales, although it may not be able to access the public network at full capacity at all times.

4.5.1 Supplier Route

The options associated with becoming a supplier are;

- A **fully licensed** supplier;
- A **Licence lite** supplier; or
- A **White Label** supplier.

Becoming a supplier is potentially a major undertaking and a number of issues should be considered before adopting this approach as a route to market. These include:

- Reputational risks – Using an existing brand to market the supply business could risk damaging the brand if the business is not run well or experiences problems.
- Commercial risks – A supply business is a commercial venture and as such is exposed to a wide range of risks. Although tying the business into a generator may reduce some of these risks through vertical integration[32], a large amount of commercial risk remains. Failure to manage these risks effectively could result in the business becoming loss making and as electricity supply is a low margin/ high volume business, the losses may be substantial.
- Market risks – A supply business is competing in a marketplace to win customers. A new supply business will need to reach a critical mass to cover its fixed costs before it will become profitable. There is no guarantee that the business will be able to grow to the minimum size required to become profitable or to retain the customers in subsequent years (although LAs may be able to leverage their own electricity consumption to de-risk the activity).
- Regulatory risks – The electricity industry is a heavily regulated industry and the regulatory environment is frequently subject to change. These changes result in system and operational costs for all industry participants.

Adopting any of the supplier routes to market should not be considered as simply an add-on to a CHP business, but rather a strategic option that needs to align with the objectives of an organisation. A full business plan for the supply business will need to be developed, and the additional benefit of incorporating the CHP into the business assessed. The electricity supply market is very competitive, so the supply business will need to identify how it will differentiate itself and whether linking itself to one or more CHPs will provide a sufficient competitive advantage.

A possible strategic approach to market entry would be for a new supplier to establish themselves as a White Label supplier. This would allow the supplier to gain a foothold in the market and for a portfolio of customers to be built up while maintaining a low level of fixed costs.

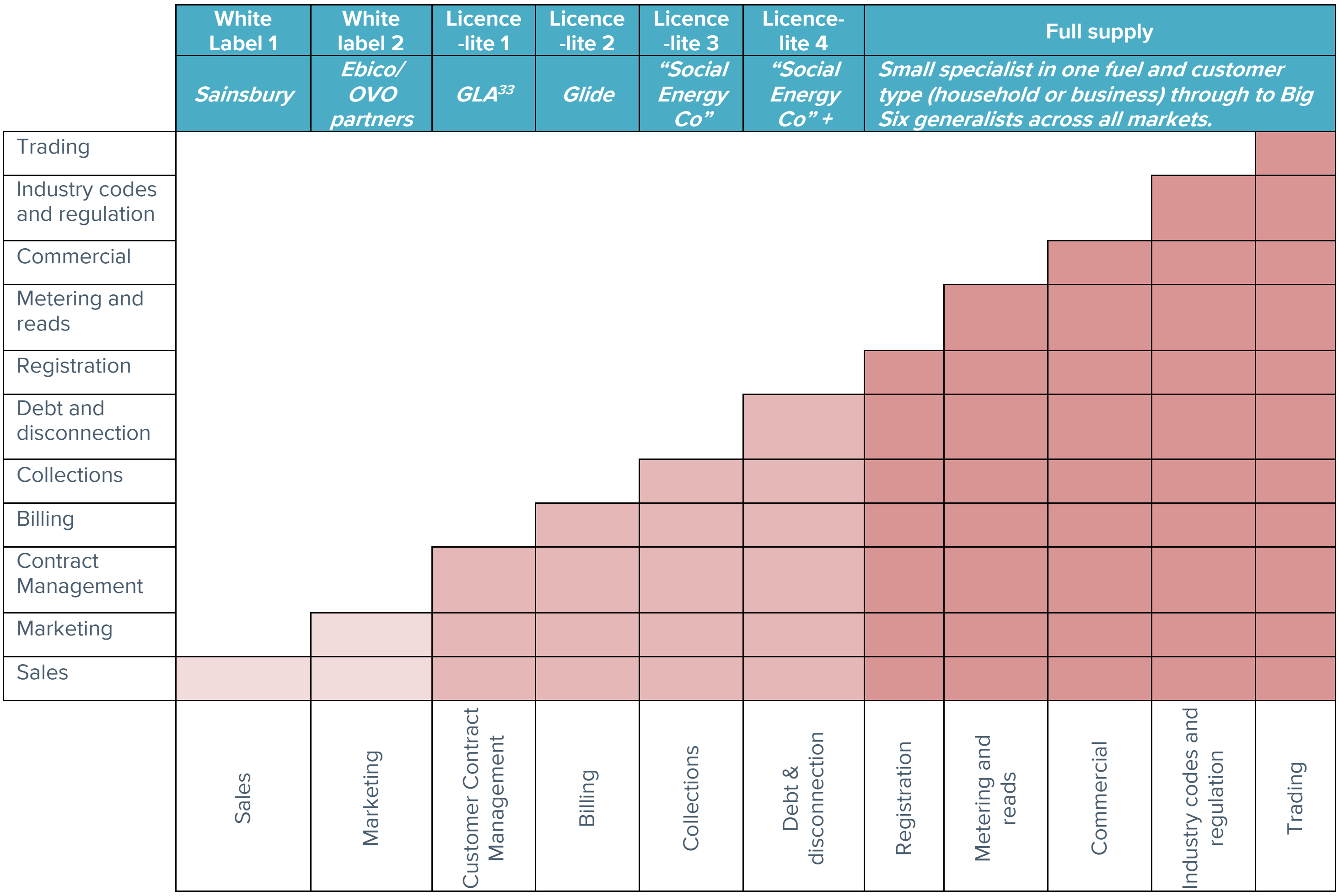
As highlighted in the route to market descriptions the difference between the supply routes can vary depending on how many business functions are outsourced and which entity has ultimate industry code and licence compliance responsibility. There is no restriction on the number of business functions that can be outsourced as long as the supplier complies with its licence conditions.

Where a supply business is set up for the sole purpose of gaining access to the wholesale market for a portfolio of generators, the core business areas that need to be developed is an in-house trading function, including credit lines with trading counterparties and IT systems to interact with central settlement systems and the cost of acceding to industry codes.

[32] Vertical integration in electricity is where a company acquires several parts of the supply chain. Vertically integrating across generation and supply reduces the risk associated with revenue derived from each component of the supply chain on a standalone basis. Some companies have also acquired distribution and transmission assets so that they own the majority of the supply chain.

Figure 14 shows the main business services provided by a supply business and where they are used within a supply business model. For example, the Licence-Lite 2 business model has outsourced the debt and disconnection activity whereas the Licence-Lite 4 business model is completing these activities in-house:

Figure 15: Services undertaken within a supply business



Where becoming a supplier is the desired route to market, deciding between the three supplier options will largely be based on the risk appetite of the owner organisation, the objectives driving the requirement to enter the electricity supply market, the set-up costs and the perceived competitive advantage that may exist. These characteristics will vary from company to company. However, a useful indication to help in this decision-making process is to define the options by market size. The cost to set up a White Label supplier is substantially lower than that of a Licence Lite supplier and the cost of becoming a fully licensed supplier can be considerably higher. As electricity supply is high volume/ low margin business, it is necessary to achieve a minimum size to be able to operate a supply business profitably under each of the options to recover both the fixed and variable costs.

These guidance notes provide an indication of the minimum market size that needs to be acquired to make each business option viable where demand customers form part of the business plan. This guidance is purely illustrative and more detail on the calculation is provided in Chapter 7. The actual minimum size will be unique for each organisation and will depend on a range of items including the mix of customers and the tariff strategy adopted. A full business plan should be developed to determine the break-even point for an individual business. The table in figure 15 provides an indication of minimum market size required to make a supply route viable which may assist in selecting a route to market:

[33] Greater London Authority

Figure 16: Types of supply and illustrative breakeven volumes

Supply Route to Market	Illustrative Breakeven Volume/yr	Equivalent Number of Domestic Customers*	Equivalent CHP size (MW)**	Illustrative set up costs (£k)
White Label	6GWh	1,935	0.8	50 – 80
Licence Lite	30GWh	9,677	3.8	250 – 750
Fully Licensed	107GWh	34,516	13.6	1,000 – 3,000

* Based on typical domestic consumption of 3,100kWh/yr

** CHP running at 90% load factor (note: it is unlikely that a single CHP can meet demand every half hour. This is presented for illustrative purposes only).

4.5.2 PPA Route where supplier route is not the preferred approach

Where the size of the target market associated with a generator or the business model of the owner does not warrant a supply business approach, the alternative option is to sell the output via an existing supplier using either a standard or corporate PPA.

The share of the benefits that a generator could expect under a PPA has increased in recent years. This is due to more standardisation of the PPA agreement and the set-up of auctions that have made the process more competitive. It should be noted that non-intermittent generation can expect to receive a larger share of benefits under the PPA as their output is predictable and less likely to create an imbalance position for the offtaking supplier. The table below shows a range of the revenues typically retained by generators under PPAs[34]. The percentages in the table below represent the proportion of revenue in each category that is passed on to the generator by the supplier:

Tendering for a PPA

CityWest Homes issues a tender to suppliers to procure their PPA for the CHP they manage in Pimlico. Historic data is used to create a half-hourly generation output profile that is issued as part of the tender.

Recent experience has shown that tendering an annual PPA contract results in the most attractive prices, primarily due to the relatively large number of offtakers willing to price a contract. Although offers are likely to give different values for specific revenue streams such as embedded benefits and power prices, the operator prioritises the total value, which can readily be modelled, when selecting a counterparty.

For more details on the case studies see Appendix 1

[34] This data has been supplied by Cornwall who monitor and provide market intelligence on the PPA market

Figure 17: PPA value retention

PPA element	e-POWER/ <1 year PPAs	1-3 year flexible PPAs	Long-term PPAs
Wholesale Power	95%-98%	92%-98%	90%-95%
Roc buy-out & recycling	95%-98%	92%-98%	90%-95%
Triad Benefit	90%-100%	90%-100%	80%-95%
Balancing Services Use of System (BSUoS)	90%-100%	90%-100%	80%-95%
Transmission losses	90%-100%	90%-100%	80%-95%
Distribution Use of System credits	90%-100%	90%-100%	80%-95%
Distribution losses	90%-100%	90%-100%	80%-95%
Management fees	£0-£1/MWh	£0-£2/MWh	£0-£3/MWh

PPAs are relatively standardised, but scope exists for negotiations to tailor agreement to suit the requirements of a generator. For instance, some generators will adopt their own trading strategy and monitor wholesale markets, instructing the supplier to trade on their behalf and self-despatch their plant. Other generators will allow the supplier to optimise their generation as part of the supplier's portfolio and schedule the plant accordingly.

One drawback of a PPA is that it typically does not provide long term price certainty and the generator is at risk of wholesale price movements leading to substantial variations in revenue year on year. Where a generator values the long-term certainty of a fixed price a PPA can still provide this, but the price achieved will reflect the greater uncertainty and lower market liquidity of long term hedges. An alternative route to market which enables longer term hedges of wholesale power prices without an excessive risk premium is to use a corporate PPA. The sleeving, peer-to-peer and synthetic PPAs route all provide different ways of ensuring longer term revenue certainty for the generator. In each of these instances the export from a generator is matched against a demand customer or groups of demand customers who are looking to secure their electricity cost over the longer term.

Sleeving and local authorities

Sleeving often occurs between embedded generators and large customers, both of which are looking to secure a long-term deal for wholesale power.

However, a sleeving or peer-to-peer agreement is equally applicable to a local authority with a large number of diversified sites that can be matched in aggregate against the expected output of a generator.

Under the sleeving and peer-to-peer approaches the fixing of revenues is achieved via the supplier who matches customers and generators who are both looking for long term certainty on wholesale electricity costs. It should be noted that although the supplier acts as an intermediary and will require compensation for this service, it is possible for the generator to interact directly with customers to determine whether a common interest exists and discuss the price and duration for such an agreement (or indeed the generator and the customer may be the same legal entity/under common control). The deal can then be taken to a supplier who will implement the solution on their behalf and charge a "tolling fee" to cover network charges, imbalance payments, top-up and spill and a service fee. It should be noted that not all suppliers offer this type of "implementation" service and it is likely that the agreement will need to be large enough to make it worthwhile for the supplier to become involved. As such, potential suppliers should be approached at an early stage to determine whether they would be willing to implement a potential agreement under this route to market.

A synthetic PPA is slightly different in that the agreement to fix wholesale costs over a fixed duration relies on both the generator and customer agreeing and implementing an agreement on a bilateral basis that does not involve a supplier. This will be typically achieved via a CfD arrangement that agrees a price for the provision of a fixed volume of electricity. More information regarding CfDs and an example of how this agreement would work in practice is included in Appendix 2 (1.7). Although this type of agreement gives price certainty, it also includes an element of volume risk. Where a CfD has been entered into for a fixed amount of electricity and the generator is unable to deliver that energy (for example due to an unforced outage) the generator will still be liable for the difference payments under the CfD. This may result in a benefit or a loss depending on the prevailing market price relative to the agreed CfD strike price. Note this arrangement does not offer any benefit if the generator and consumer are the same legal entity/under common control.

4.5.3 Credit Risk

Under each route to market, consideration must be given to the credit implications of each option. The level of credit risk associated with a route to market is dependent on the credit worthiness of the counterparty and how diversified this risk is between different counterparties. An assessment of the risk in each case is shown in the figure 17:

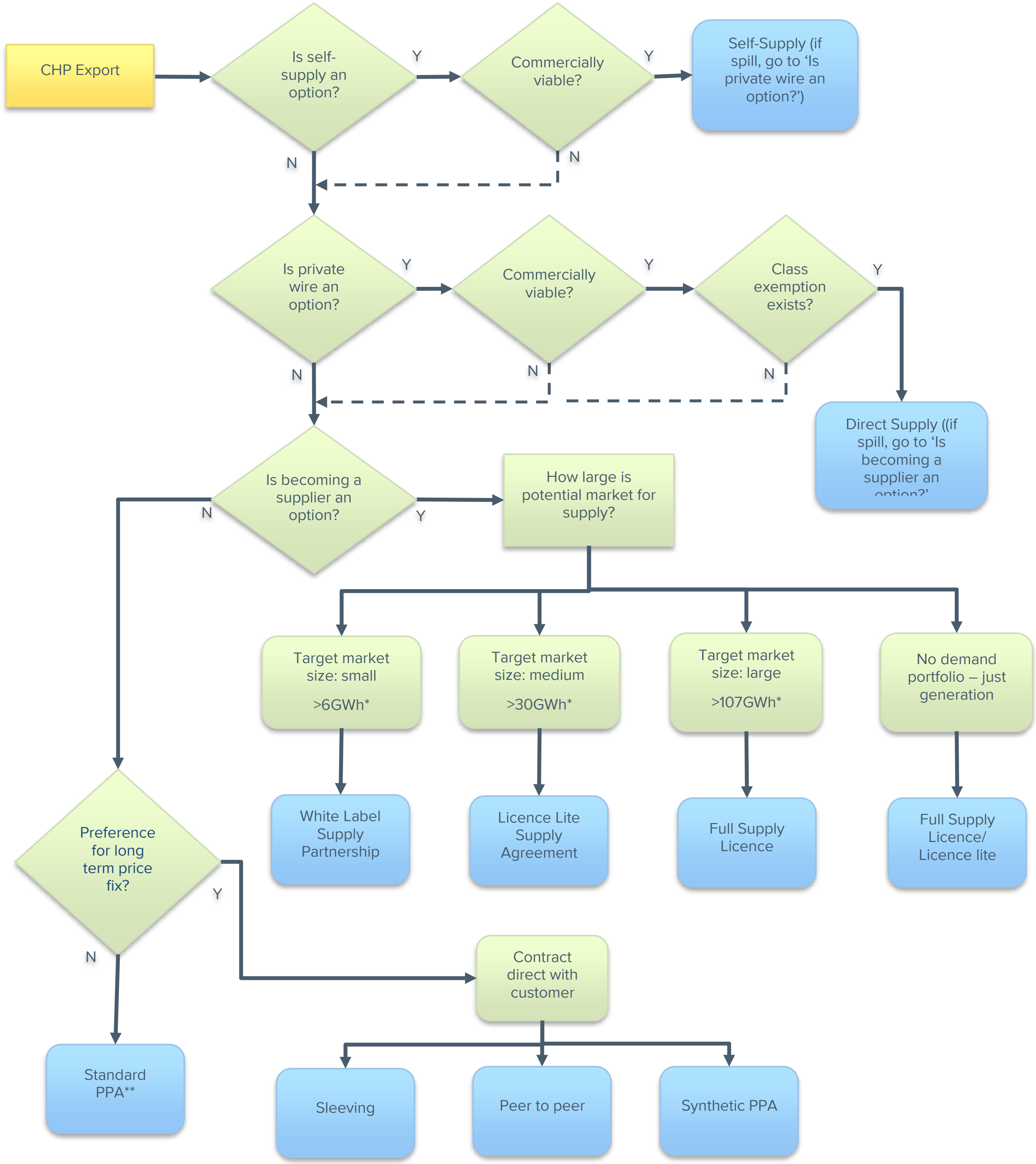
Figure 18: Credit risk associated with routes to market

Route to Market	Assessment of Risk	Risk Rating
Direct Route (Self-Supply)	• Generator is owned by the same entity as the demand, resulting in offsetting credit risk. The credit risk will also be lower where the generation profile more closely matches the demand profile as any top up or spill requirements will be reduced.	LOW
Direct Route (Private Wire)	• Where private wire is connected to a few large customers, impact of credit risk is high • Credit risk can be mitigated by contracting with low risk customers such as local authorities • Risk can be diversified by connecting to a larger number of small customers • Agreement can include terms that offset the credit risk such as letters of credit, provision of collateral and payments made in advance • Where the private wire includes connection to domestic customers, the risk of bad debt must be managed. This will require the implementation of processes such as repayment schemes, using debt collection agencies, and introducing a charging structure to recover the cost of bad debt	HIGH
Supply Route (White Label/ Licence Lite/ Full Licence)	• From a supplier perspective, credit is one of the many risks that needs to be managed within the supply business • Suppliers tend to have a large portfolio of demand customers which results in a diversification of credit risk • Each supply business controls the types of agreements that they have with end customers, including payment terms, which can offset credit risk • Suppliers have the ability to target certain customer types, which may lead to a higher or lower credit risk profile depending on the strategic aim of the supply business • The size of the supply business and the mix of customers supplied will determine the overall credit exposure of the organisation • Suppliers need to establish processes to manage credit risk and recovery of bad debt	MEDIUM
PPA Route (Sleeving/ Peer to Peer)	• Agreement must state where the credit risk sits. If the supplier who is facilitating the deal takes on the credit risk, this will be incorporated into the fee. • Where the credit risk is between the end customer and the generator, then the risk is potentially high as the agreement tends to be with a small number of large customers (although can be eliminated where generator and end customer are the same legal entity/under common control). • Risk can be mitigated by paying the supplier to adopt the credit risk or by contracting with low risk customers such as local authorities	MEDIUM
PPA Route (Synthetic PPA)	• The generator contracts separately with a supplier and end customer. • The credit risk with the supplier is the same as under the standard PPA arrangement (see above) • The credit risk with the end customer will amount to the difference payments that are liable under the CfD. As these payments are for the difference between the market rate and the agreed strike price, the magnitude of these payments is smaller than the gross payment from the supplier, so the additional risk is not substantial	MEDIUM
PPA Route (Standard PPA)	• Degree of credit risk is dependent on the credit worthiness of the supplier • Supplier will need to meet the credit requirements of the industry codes which offers some protection • Historically, there have been some suppliers who have defaulted • Credit rating of supplier should be taken into account	MEDIUM

4.5.4 Route to Market Decision Tree

The figure below shows a decision tree to assist stakeholders in assessing the different routes to market:

Figure 19: Considerations for choosing a route to market



** Based on a mix of 50% domestic and 50% non-domestic*

*** Note, it may be difficult to secure a PPA if an embedded generator is below a minimum size and this should be taken into account when sizing a CHP*

4.6 Summary of Benefits and Risks

Figure 20: Summary of route to market benefits, risks and issues[35]

	Benefits	Risks/ Issues
Direct Route (Self-Supply)	• Potential for highest income • Simple to implement • Minimal administration burden • Avoids licensed supplier costs • Less exposed to direct movements in the wholesale market	• May require additional on-site infrastructure and associated cost • Additional cost to guarantee route to public network if on-site demand reduces • Behind the meter generation identified as priority area for review by Ofgem*
Direct Route (Private Wire)	• Potential to capture high price for power • Small administration burden when selling to a small number of large customers • Potential for long term certainty via offtake agreement • Avoids licensed supplier costs • Less exposed to direct movements in the wholesale market	• Additional cost to install and maintain private wire • Need class exemption from requirement to hold supply and distribution licences • Administratively complex if many consumers • Additional cost to guarantee route to public network if private wire demand reduces • Behind the meter generation identified as priority area for review by Ofgem*
Supply Route (Full Licence)	• Has full control of business model, tariffs and marketing • Customers registered with supplier • Has flexibility to optimise CHP output against demand portfolio	• Large set up costs • Needs a minimum size to become profitable • Risk associated with not winning or failing to retain customers at an adequate margin • Needs to comply with full licence obligations
Supply Route (Licence Lite)	• Captures a reasonable element of supplier margin • Lower set up costs compared to full licence option • Customer contracts with Licence Lite supplier • Avoids the complexity of managing compliance with industry codes • Enables brand to be established and niche marketing for export from CHP • Has flexibility to optimise CHP output against demand portfolio	• Needs a minimum size to become profitable • Risk associated with not winning or failing to retain customers at an adequate margin • IT systems needed to link Licence Lite supplier to senior supplier • Licence lite supplier cannot place senior supplier in breach of their licence conditions • Uncertainty related to end of contract with senior supplier
Supply Route (White Label)	• Captures small element of supplier margin • Low set up costs compared to Licence Lite and full licence options • Enables brand to be established and niche marketing for export from CHP	• Needs a minimum size to become profitable • Risk associated with not winning or failing to retain customers at an adequate margin • Customers are registered to the senior supplier • White label supplier must ensure senior supplier is not placed in breach of their licence conditions
PPA Route (Sleeving/ Peer to Peer)	• Provides long term certainty on revenue • CHP can approach and agree terms directly with customer	• Supplier required to implement agreement • A PPA is still required for the CHP
PPA Route (Synthetic PPA)	• Provides long term certainty on revenue • CHP can approach and agree terms directly with customer • No suppliers involved in agreement	• Basis risk[36] may exist between actual price and reference price • A PPA is still required for the CHP
PPA Route (Standard PPA)	• Standard PPA is simple to implement • Competitive auctions mean PPAs retain high proportion of revenues	• Suppliers retain share of revenue • Standard PPAs tend to be short term

[35] It should be noted that all routes to market are exposed to some degree of regulatory risk. These are considered in more detail in Chapter 10
[36] Basis Risk is the financial risk that offsetting investments in a hedging strategy will not experience price changes in entirely opposite directions from each other

4.7 Chapter summary

There is a clear economic hierarchy for the routes to market options available for the electricity output from a CHP, although the individual circumstances of a project need to be considered in each case. A direct approach is likely to offer the best return, but the project will need to take account of the cost of private wire and consider a contingency plan if the demand is not present at a later date. Many of the case studies used in these guidance notes have found that a private wire approach can result in a significant increase in electricity revenue.

Where a direct route to market is not possible, becoming a supplier offers the opportunity to enhance returns over and above the income that can be expected from a standard PPA. However, setting up a supply business is a substantial undertaking and significant upfront costs can be expected. These costs will be highest for a fully licensed supplier, lower for a Licence Lite option and cheapest for a White Label option. The Licence Lite and fully licensed routes to market also open the possibility of accessing the wholesale market for a portfolio of generators without the complication of demand customers. However, the high fixed costs associated with this option need to be balanced against the incremental benefit of directly accessing the wholesale market. Whichever, option is selected, the expectation must be that a large portfolio of generators or customers will be developed that will offset the fixed costs in each case.

Where a CHP does not want to set up a separate supply business and a private wire approach is not viable, the PPA route is the remaining option. In this case, the PPA offers a well understood and developed approach to accessing the market, with the ability to customise the PPA to suit specific requirements. The PPA can also be enhanced by using the peer to peer, sleeving or a synthetic PPA. All of these enhancements can improve the standard PPA by offering longer term security or by establishing a greater share of benefits through the PPA. It should be noted that the increased share of benefits is more likely to arise where the generator sources the demand customer and brings the package to a supplier for implementation. This allows the supplier to save on customer acquisition costs which can be shared between both parties.

5 Strategic Aims and Considerations

What is covered in this chapter?

This chapter identifies the key strategic drivers that may influence stakeholders in the approach they adopt to developing heat networks and exporting power. Depending on the strategic drivers that are adopted this may influence the route to market chosen as the ultimate solutions. The following topics are covered:

- Understanding strategic objectives
- Importance of continually revisiting objectives during business plan development
- Key role for planning and mapping
- The interaction between stakeholder objectives and choosing a route to market for generation export

5.1 Introduction

The business model for a CHP deployment is largely dependent on the policy objectives that the developer is seeking to realise. In turn decisions relating to how the CHP installation is to be operated (e.g. heat or power led) will determine the most appropriate route for sales of export power. Where a CHP is heat led, this allows for a more stable and predictable running regime which is easy to plan against and the electrical output is frequently seen as a by-product. However, where a CHP is power led or at least looks to maximise the income from the electrical import for the CHP as a whole, there is more complexity, but also more potential to optimise the running regime and maximise the value. The case studies within Appendix 1 illustrate the additional value that developers have realised by focusing more on the power side of a CHP. In some instances, this can make the difference between a project being economically viable and is an important consideration when developing a business model.

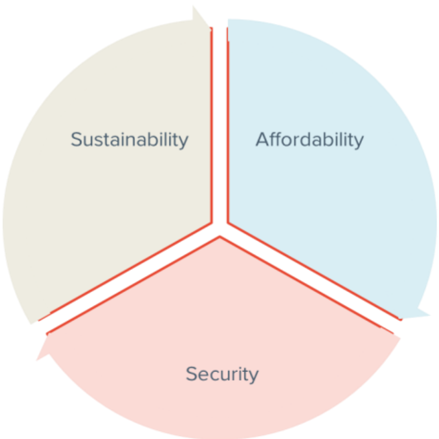
Any business plan will undergo several iterations as costs and timescales are firmed up and must be regularly checked against the project's objectives.

5.2 Key objectives for owners of heat networks

Heat networks can play a pivotal role in helping meet local, regional, and national goals to reduce carbon emissions, tackle fuel poverty, facilitate regeneration, boost local investment and employment. The development of heat networks, including the sale of electricity where CHP is deployed, is typically arrived at as part of the wider local planning process and strategic aspirations.

There are more than 400 local authorities across GB with different levels of power, political make up, and priorities. Despite these differences developers, especially local authorities, will often begin from the position that heat networks coupled with electricity generation that have the potential to deliver sustainability, affordability and security goals.

The Energy Policy 'Trilemma'



Local, regional, and national energy policy is framed within the so called ‘trilemma’ (see chart). The competing strands of policy will mean that it is not typically possible to deliver all three in equal measures, although there are often overlapping benefits that can be realised simultaneously.

This section sets out the key objectives for operators of CHP and how the competing objectives can be managed to achieve the desired outcome.

It should be noted that a common theme for a successful development is the clear identification of the project aims at the outset and the ability to understand the trade-offs between competing objectives to ensure project viability and buy-in from stakeholders.

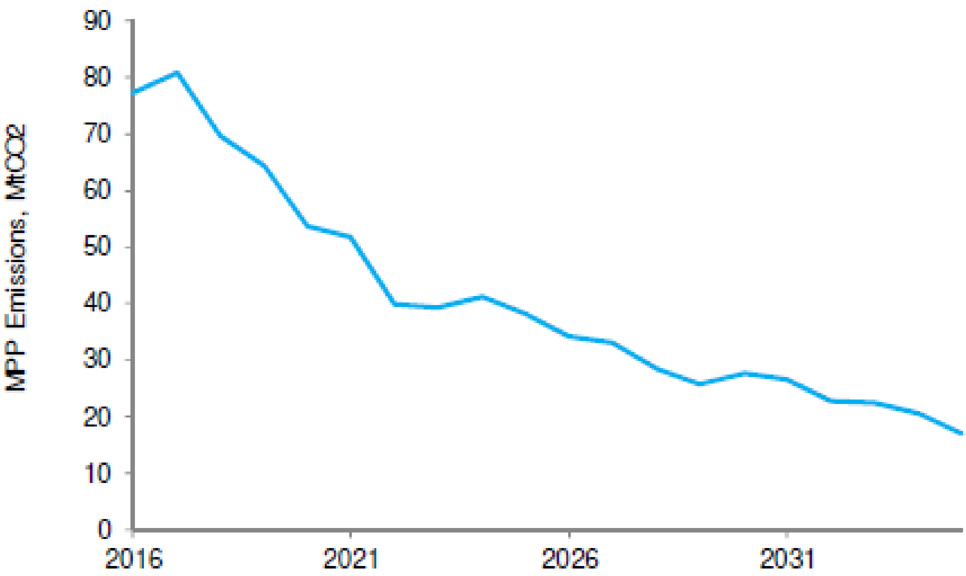
5.2.1 Sustainability

At the point where heat networks are introduced as an alternative to conventional sources of heat and power, they can significantly reduce associated carbon emissions. CHP provides one of the most efficient means to produce power and heat with very little energy wasted compared to other approaches. Installations may also negate a requirement for separate boilers or electric heaters within individual premises.

The process of ‘fuel switching’ is particularly beneficial where the user is reliant on oil or electricity for their heating needs as these fuels are particularly carbon intensive. This benefit is greater where the CHP unit is fuelled by renewable sources.

Compared to more conventional means for providing users with heat and power, a CHP plant will produce fewer emissions when compared to taking gas for heating and a separate supply for electricity. This incremental benefit needs to be judged against the overall emissions of providing both commodities via the National Grid. BEIS[37] has published forecasts that show their expectation that the emissions associated with supplying electricity will fall substantially over the next ten years and this needs to be factored in to a judgement on the sustainability of a project. The BEIS prediction[38] for emissions associated with future electricity demand is provided below to illustrate the size of this reduction:

Figure 21: CO2 emissions from electricity supply sector



[37] Department for Business, Energy and Industrial Strategy
[38] Data sourced from BEIS UPDATED ENERGY AND EMISSIONS PROJECTIONS 2016

When using a CHP solution, overall efficiencies upwards of 90% are possible, and where the heat and power are consumed locally these benefit from reduced energy losses associated with moving electricity large distances from large-scale power stations. Exported electricity that is consumed within the locality can also deliver wider electricity network benefits. By siting generation close to demand (such as urban environments), there is less reliance on the local distribution network and transmission network[39]. This can result in lower network reinforcement costs for the distribution and transmission network operators and a carbon saving resulting from fewer assets required to serve the customer. However, it should be noted that given the large number of generators that are connecting to distribution networks, in some areas the distribution networks are becoming generation dominated[40]. In these areas, connecting additional generation may lead to more network assets being required by the network companies which would increase the connection costs and indirectly increase the carbon footprint of the development. The local distributor will be able to provide information to a CHP developer on whether a network location is demand or generation dominated and the impact this may have[41].

Additional flexibility can be added into the site through the incorporation of storage, either through heat storage, which is an established technology or electricity storage which is an emerging technology. The ability to store either heat or electricity can add significantly to the flexibility of the running regime of the generator and enable a more efficient use of network assets. For example, if the local network is constrained due to too much export from embedded generators, the electrical output could be used to charge up a battery rather than spilling onto the distribution network.

Where carbon reduction is the primary objective for an installation it will be necessary for developers in their business planning activity to identify the following:

- How much carbon will be saved due to the development of this project relative to alternative developments?
- Can carbon savings be forecast into the future/ life of the asset?
- What are the local air pollution considerations?
- How much carbon tax spend does the development potentially save?
- Are there potential changes/ future upgrades that can realise additional carbon savings (e.g. installation of electrical storage technologies, accessing contracts from network operators to help manage the wider electricity system, coupling with other on-site generation assets, etc.)
- How does a sustainability objective help meet affordability and local energy and economic security objectives?

5.2.2 Affordability

Energy costs remain a major concern for many business and household consumers. According to official figures around 10.6% of households in England[42], 34.6% in Scotland[43], and 23% of households in Wales[44] are in fuel poverty. Customer bills are projected to continue to increase over the coming years as the industry invests in new power stations and network infrastructure.

[39] The locational element of the Transmission Network Use of Service charge provides an indication of where it would be most beneficial for a generator to connect from a transmission network perspective. This data is available on the National Grid 5 year forecast of tariffs here

[40] Generator dominated networks occur where many generators connect to the public network, but there is insufficient demand locally to absorb their export. This typically occurs in rural areas rather than urban areas where there are normally insufficient demand customers to utilise the generation export. An example of a generation dominated network is the "Cumbria ring" in North West England which has several large power stations connected to it, but very little demand close by.

[41] DNO's publish locational prices (referred to as nodal prices) alongside their charging statements within the "Schedule of charges and other tables". Links to the DNO websites are available from the Energy Networks Association website here.

[42] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/557400/Annual_Fuel_Poverty_Statistics_Report_2016_-_revised_30.09.2016.pdf

[43] http://www.gov.scot/Topics/Statistics/Browse/Housing-Regeneration/TrendFuelPoverty

[44] http://gov.wales/topics/environmentcountryside/energy/fuelpoverty/?lang=en

Local production of heat and electricity has the potential to provide warmth and light at a lower cost than the conventional market primarily due to the close proximity of providing both services, where elements of charges associated with moving gas and electricity over long distances can be avoided (see section 3.5 for more on embedded benefits) and the higher efficiency that can be achieved.

Depending on the specific arrangements it may also be possible for the CHP asset to gain extra revenue from offering balancing services to National Grid as System Operator (see Chapter 9) and/ or to receive other subsidies such as the Capacity Market[45]. Additional revenues can be part shared with consumers through reduced heat or power costs.

New build sites will also benefit from the most current thermal efficiency standards and can be built with the option to install on-site storage to seek more revenue from wholesale price arbitrage or balancing service revenues. Installations that are successful at reducing energy spend for low-income or vulnerable consumers can in turn effect the Social NPV[46] of a scheme.

Where energy affordability is the primary objective for an installation it will be necessary for developers in their business planning activity to identify the following:

- Projected revenue from sales of heat and power
- Projected end costs for consumers of locally generated heat and power
- How will consumers contract to purchase heat and power?
- What is the outlook for conventional market gas (for heating) and power prices to ensure local production is less costly?
- Can average cost savings be quantified for local consumers?
- Are there other quantifiable or qualitative benefits that can be delivered to local consumers?
- How does an affordability objective help meet sustainability and local energy and economic security objectives?

5.2.3 Energy and economic security

Where heat networks with power offtake are installed they can bring long-term benefits to the local economy and energy security. Developments can be built as part of the wider regeneration of green- or brown-field sites and be a key measure to attract businesses or residents to the area through lower energy bills.

The build out and operation of networks brings employment opportunities, and, where owned by local authorities, helps keep local energy spend in the local economy. Where an installation is part of inward local authority investment it too delivers immediate and long-term benefits to the public estate through long-term lowering and potentially de-risking of energy spend uncertainty across the estate.

Depending on the commercial presence a local authority takes (i.e. the local authority or an arm's length body could become the retailer of heat and electricity) it could leverage existing relationships with residents and businesses to provide energy advice, soft loans to improve business productivity, and package energy up with a wider social offering.

An installation may also contribute to local energy security by easing pressure on the existing gas and electricity networks that in many cases are constrained and may not readily allow for new connections. Where local energy and economic security is the primary objective for an installation it will be necessary for developers in their business planning activity to identify the following:

[45] The stacking of potential revenue sources is discussed in section 9.1.3

[46] More information on social NPV is available from the VALUATION OF ENERGY USE AND GREENHOUSE GAS report published by BEIS

- Projected revenue from sales of heat and power
- Which commercial vehicle delivers the greatest benefits (considering all risks) for the locality/ public estate?
- Local employment opportunities, including potential for energy retail presence
- Are there other quantifiable or qualitative benefits that can be delivered to local consumers, e.g. 'soft loans' to businesses, improved targeting of social care services, etc.?
- How does an energy and economic security objective help meet sustainability and affordability objectives?

5.3 Implications of competing objectives

All projects will be conceived with at least a notional primary objective that delivers a local authority strategic aim. Once sufficient mapping and planning work is completed the project objectives can begin to be evaluated for feasibility. As the costs and timings of the project (and the underlying value of heat, power and carbon) become clearer it will be necessary to regularly assess how the project will deliver its objectives.

Given it is unlikely that any project can meet several competing aims concurrently and successfully it is highly advisable to set out a hierarchy of objectives for the project. For example, an installation that has the primary objective to tackle affordability and provide lower energy spend for social housing tenants will need to focus on current market prices and costs and forecast prices for gas and electricity to assess if local heat and power can be sold to end users more cheaply. This approach will also likely bring lower carbon emissions, but may have to forego any aspiration to be fuelled by certain types of renewables due to extra costs that would undermine the affordability objective.

Where investment is driven primarily to produce renewable heat and power the planning and feedstock supply chain considerations will help meet wider local/ regional economic and sustainability goals, but may struggle to also provide the least cost heat and power to local consumers.

Assessing competing objectives is further complicated by the requirement to have a business plan consider project objective over several years. The best view of today's energy prices, supply chain costs, construction costs etc. will of course change over time. But where external advisors are well placed to provide credible forecasts other more qualitative characteristics should be considered too.

For example, the cost of electricity generated by CHP is largely driven by the underlying fuel input cost. Depending on how this is procured and the nature of how export power is sold to the market or local consumers it may provide for a less volatile and more predictable source of electricity, which helps the public estate and consumers' budget.

5.4 Routes to market and stakeholder objectives

Reviewing the potential options for selecting a route to market for the electrical export from a potential heat network project needs to be undertaken in the context of the stakeholder objectives. The routes to market comprise technical, regulatory and commercial considerations that will contribute greatly to the shaping of the business model and business case. Below, each of the three high level objectives are considered separately to show how they may impact on the decision making process of selecting a route to market.

5.4.1 Routes to market and the sustainability objective

The sustainability for a CHP scheme arises due to the efficiency gains of providing both heat and power. These schemes are therefore inherently sustainable due to the higher efficiencies that can be achieved when compared to conventional generation. The sustainability of CHP schemes can be further enhanced through the use of renewable fuels such as biomass to fuel the CHP. However, the business case must remain viable over the long term and therefore when considering the route to market options the project must be assessed against the degree to which they maximise revenue and therefore enable a sustainable objective to be fulfilled regardless of the fuel source used. Where a direct route to market is considered, the sustainability of the additional network infrastructure that is required should also be considered. Network assets are a long-term investment and therefore this decision should align with the long-term vision for the development, including anticipated future connection of demand customers and whether the private network could encourage investment within the local area.

The sustainability of a potential CHP scheme is normally measured though the efficiency of the installation and the carbon savings that can be realised. This will be a function of the fuel type and the distance through which the power and heat needs to travel to the end consumers. As a rule, siting the generation closer to the end customers for both heat and power will result in larger carbon savings as there will be lower network losses. In addition offsetting local demand can reduce the need for any reinforcement cost expenditure on the distribution network and transmission networks.

When comparing routes to market from a sustainability perspective, the difference in carbon savings mainly arise where a project can choose between installing a private wire or using the DNOs network. Where this is an option, using the existing DNOs network will result in a lower carbon footprint as fewer assets need to be constructed. However, it may well be a less economic route for the project.

Where the investment in assets to connect a generator to a consumer can be achieved either through investing in the DNOs network or via a private wire, the route to market does not impact on the carbon savings and sustainability of the project. However, what is impacted is the degree to which the sustainability benefits are captured by the generator and consumers. Where a private wire route to market is used the full sustainability benefits are captured and can be shared between the generator and consumers whereas when the public distribution network is used, some of the benefits do not accrue directly to the generator but are instead socialised across all network users.

5.4.2 Routes to market and the affordability objective

The affordability of a project is the objective that is most impacted by the route to market chosen. A comparison of the values between the routes to market identified in these guidance notes can be seen in Chapter 7.

As mentioned in the Executive Summary, the route to market chosen will depend on the economics of the project and the flowchart provided earlier (figure 16 Considerations for choosing a route to market) shows the factors that will need to be considered. The most economic route to market will vary from project to project, but the general hierarchy is as follows:

1) Self-supply – Most economic route as offsets full demand cost
2) Private wire – Offsets full demand costs of end users, but additional cost associated with private wire, plus some complexity on contractual arrangements
3) Supplier route – Becoming a supplier, either White Label, Licence Lite or full licence, can enhance earnings when compared to PPA route, but a minimum size portfolio needs to be acquired in each case to recover fixed costs
4) Corporate PPA route – Using a peer-to-peer, sleeving or synthetic PPA can result in improved margins compared to a standard PPA
5) Standard PPA – A simple, low risk route to market, but revenue is likely to be lower than the routes to market above.

The affordability objective is more than just considering which route to market has the lowest capital or ongoing costs. For a local authority, affordability may consider the ability of vulnerable customers or customers in fuel poverty to pay for the electricity. For instance, if a local authority is targeting a reduction in fuel poverty for end consumers it could decide to set up as a supplier (White Label, Licence Lite or full licence) to sell the export from the CHP to those customers who would benefit the most. It may be that the project could achieve better economics by selling direct to a local industrial site, but the local authority's overriding target of reduced fuel poverty means they may select a slightly less economic route to ensure the benefits are shared across the community.

An additional advantage of this approach is that it may encourage end customers to engage with the market and move from an expensive Standard Variable Tariff (SVT) to a competitive local tariff. This could yield higher savings in total when measured from a customer perspective.

5.4.3 Routes to market and the security objective

Security can be considered as security of electrical supply or economic security of providing a reasonably low cost source of electricity over the long term. ***Where customers are connected to a local generator via a private wire arrangement they may perceive that they are more dependent on that generator and that the quality of their electricity supply will be lower with more interruptions. In reality, the majority of private wire agreements incorporate a backup connection to the public network, so supply will be constant even if the local generator fails.*** In some cases, a generator and group of customers may be separated from the public network and have an "island" arrangement. This will normally require a main generator, plus backup generator or storage to enable the demand to be met at all times. Within GB, this type of arrangement is not prevalent, although it has begun to emerge as a business model in several countries, primarily due to the take up of storage.

One of the key advantages of CHP is that projects tend to be located close to end consumers which reduce infrastructure investment to supply customers. In addition, because the generator is connected near end customers, it may be able to provide a source of supply security in the event of a fault or outage situation. This benefit can be achieved as the embedded generation replaces the need for backup network as set down in the network planning guidelines contained in Engineering Recommendation P2/6[47].

Where economic security is an objective, the project will need to address the concern that electricity prices may rise substantially in the future. However, it is difficult to fix retail prices in the longer term without excessive risk premiums being applied to tariffs. Embedded generation, such as CHPs can use a route to market that enables both the generator and end consumer to agree long term prices for their power. This is possible through all three categories of routes to market considered within these guidance notes, with the exception of a standard PPA. The standard PPA is normally short term in nature and where it is longer term, the electricity price element tends to link to wholesale market prices.

Security of supply benefits on Isle of Gigha

The Isle of Gigha is situated off the coast of Scotland and has around 150 residents. The electricity is supplied via one of the longest 11 kW overhead lines in Scotland. This line is prone to faults and power cuts, especially during extreme winter weather and residents suffering a five-day power disruption in 2016.

To overcome the issue of poor security of supply and to take advantage of the natural resources present, three wind turbines have been installed with plans to install an additional turbine, a solar farm and a battery. This infrastructure will enable a more continuous supply of electricity to residents when there is a fault on the cable into the island and is a good example of the benefits of integrating embedded generation and storage into the distribution network.

It should be noted that where a CHP and consumer agree to fix a price between them the price components will depend on the route to market. For instance, if a private wire agreement is selected, the price agreed for the electrical output will replace the retail tariff that the end customer would otherwise pay. However, when the route to market is via a standard PPA, corporate PPA or supplier route, this fixed price will apply solely to the wholesale element of the bill and additional third-party costs will be passed through.

The long terms arrangements that can be agreed between a CHP and end consumers need to reflect the balance of risk between both parties. It may be that the end consumer signs up for a fixed duration at an

[47] Engineering Recommendation P2/6 specifies the minimum standards that DNOs must adhere to when planning their networks

indexed price or, in some agreements, the CHP will guarantee that the end customer gets the current market rate less a fixed percentage.

5.5 Other considerations

The establishment of clear objectives for a project and their prioritisation is an important requirement that should be established at a project outset. Where a number of developments are under consideration, they can be assessed and prioritised based on their ability to meet the priority objectives of stakeholders. However, this is not a one-off exercise and should be considered as a starting point for an iterative process that continually checks a project's progress against the initial objectives and the degree to which they are being met.

The high level stages of development for a heat network as used by HNDU are set out in the table below:

Figure 22: Development stages for a heat network

Phase	Detail
Heat Mapping	Area-wide exploration, identification and prioritisation of heat network project opportunities. This stage will pinpoint possible heat networks for further assessment.
Energy Master Planning	Area-wide exploration, identification and prioritisation of project opportunities associated with heat and power. This will be used to identify where there may be a technically-feasible and financially-viable project.
Feasibility Study	Opportunities identified at heat mapping and masterplanning will feed into an investigation of the technical feasibility, design, financial modelling, business model identification, customer contractual arrangements and delivery approach.
Detailed Project Development	Detailed Project Development (DPD) is the detailed planning phase for the spending proposal; during this stage, the project should move from a concept to an investable opportunity. This requires the endorsement and approval of the relevant decision maker(s), who need to be sufficiently confident in the Outline Business Case (OBC) to commit the necessary resource and finance to enable the project to proceed
Commercialisation	Reasonable legal costs such as in relation to developing customer commercial agreements, heat supply contracts, necessary land purchase, land access arrangements, etc.; further development of tariff structure for customer contracts; further development of financial model and business case and associated commercial advice costs where necessary

5.5.1 Business case

The development of a business plan for a project will be taken in the context of the priority objectives. At a high level, there are four main stages for the completion of a business case for CHP deployment. The first is to assess locations and areas via a mapping and masterplanning exercise to identify where a CHP installation would be most effective. This process normally includes the identification of specific buildings that have sufficient heat demand to underwrite a minimum size development by acting as anchor loads. The project can then be extended to capture further heat customers and the heat source expanded accordingly. The second is to undertake a detailed feasibility study to quantify and capture the necessary works and reach of a CHP installation and associated heat network. This should also include an assessment on how generated electricity can be exported to either local consumers or onwards to the wider market via the public network.

The third phase is to produce a detailed project development plan and work on an outline business case (OBC)[48], for construction, commissioning and operation of the installation. Finally, commercialisation will involve determining the correct technical solution that meets the project's objectives, development and negotiation of contracts, organising finance for the project, delivery of procurement activities and final approval of the Full Business Case. The business plan will capture the early stage of the development including how heat and power are sold to end users.

The development of a business case for a CHP will be assessed against the priority objectives but will also be determined based on an assessment of the potential routes to market for the electrical export from the CHP. These routes to market are considered in detail in the remainder of these guidance notes. However, it should be noted, that the development of a business case will be greatly influenced by the route to market options available and the implications of choosing a particular route. Each route to market will need to be assessed to determine whether it is feasible, the cost implications and how well it meets the policy objectives for the development. This will require an iterative process to allow each route to market to be explored in the context of the project objectives, but also to determine the magnitude of the benefits. For example, a private wire agreement may yield such economic benefits over an alternative route to market, that the affordability objective may be advanced over a competing objective.

5.5.2 Planning considerations

Local authorities are subject to the Localism Act 2011 that made changes to planning by introducing a new "duty to co-operate" for the planning of the sustainable development of land. To clarify planning policy the National Planning Policy Framework was introduced in 2012. This sets out that local authorities should identify within plans areas suitable for renewable and low-carbon energy development and the criteria used to determine their selection. "Masterplanning" enables local authorities to assess the opportunities which emerge from their low carbon evidence base outputs (including heat mapping) and to produce a robust area-wide strategy that maximises the opportunity for schemes.

The planning framework is focused on identifying areas where low-carbon generation is suitable. Moreover, many local authorities have local targets to reduce carbon emissions and improve local economic and social conditions.

This initial step for any business plan for a CHP installation by a local authority must be completed prior to undertaking a detailed assessment of which objectives a project can best realise.

5.5.3 Electricity network considerations

During the planning stages for a project (normally at feasibility stage) it is necessary to liaise with the connections business of the local DNO where a connection to their network is required. DNOs are required to provide information on the process for connecting to their network including timescales and costs. An early dialogue is essential as some networks are constrained and providing a new connection can be costly and time consuming. Although the DNO needs to be involved in the process, it should be noted that any areas of the connection work that are deemed to be contestable by the DNO could be undertaken by a third party.

Each DNO makes available its Common Connection Charging Methodology (CCCM). This sets out the steps to take when seeking a connection including the works that can only be completed by the DNO and elements that can be completed by third parties. The CCCM also provides information on the costs of connection that will be borne by the DNO and those that the organisation wishing to connect face.

Even where an existing connection is intended to be used for a new project it is still necessary to check with the DNO that the connection is suitable for the intended use.

[48] Details on putting together a OBC, including a template is contained in the first section of HNDUs DRAFT: DETAILED PROJECT DEVELOPMENT GUIDANCE DOCUMENTS

5.6 Other sources of information

- Heat Network Development Unit (HNDU)
- Chartered Institution of Building Services Engineers (CIBSE) Heat Networks: Code of Practice for the UK
- The Town and Country Planning Association (TCPA) - Energising Masterplanning and Planning for Energy and Climate Change
- Communities and Local Government Committee (CLDC) - Operation of the National Planning Policy Framework
- Planning and Climate Change Coalition (PCCC) - Planning for Climate Change – Guidance for Local Authorities and Planning for Climate Change: A Manifesto for Building England's Resilience
- Arup - Decentralised Energy Masterplanning Toolkit
- Ofgem - Local Energy in a Transforming Energy System
- Energy Networks Association – information on DNOs including links to each DNO's own website
- Energy Networks Association – DNO Distributed Generation Connection Contact Details

6 Regulatory Constraints on Routes to Market

What is covered in this chapter?

This chapter focuses on the regulatory constraints that may exist for each of the eight routes to market that are identified in these guidance notes. The constraints are explained and the conditions under which they would apply are highlighted to help the reader determine whether a route to market is valid for a potential project. The following topics are covered:

- A description of the class exemptions from the requirement to hold an electricity supply, distribution or generation licence
- A description of the restrictions that may apply to a local authorities powers to sell electricity
- A description of the ways in which State Aid impacts on what a Local Authority can do or how it provides support

6.1 Introduction

There are a number of regulatory considerations that may rule out some of the routes to market immediately for the electricity exported from a CHP. This is important as identifying those routes to market which are not valid at an early stage of a development can save time and money for a project. In addition, it allows stakeholders to devote more resources to those routes to market that are feasible. This section provides a summary of these constraints and provides a more detailed assessment of when the constraints may or may not apply.

The first area considered is the legislation governing electricity supply and distribution licensing and exemptions. This legislation requires anyone who generates, supplies or distributes electricity to hold a licence unless they benefit from an exemption from the requirement to hold a licence. The ability to benefit from an exemption is important for those CHP projects looking to use a ***direct route to market*** (i.e. either using a private wire or self-supply approach[49]).

The second area considered in this chapter is the legislation that impacts on the ability of a local authority to operate in certain areas such as the supply of electricity. This legislation impacts a local authority for ***all the routes to market*** under consideration within these guidance notes.

The final area considered is state aid and where this may place a constraint on a CHP project's route to market. This area is an important consideration for all the routes to market under consideration under these guidance notes.

[49] The meaning of 'self-supply' in this context is considered further below.

6.2 The Electricity Act and Class Exemptions

Overview:

It is a criminal offence to generate, distribute or supply electricity without a licence, unless the person carrying on that activity benefits from an exemption granted by the Secretary of State or falls within a ‘Class Exemption’.

‘Class Exemptions’ are granted under the Electricity Act (Class Exemptions from the Requirement for a Licence) Order 2001. Of particular relevance to readers of this note, there are exemptions covering, amongst other things:

- generation, distribution or supply below certain thresholds
- distribution or supply involving only limited or no domestic supplies
- generators making on-site supplies or supplies over ‘private wires’
- re-sellers of electricity.

Some of the criteria determining eligibility for the Class Exemption are complex so legal advice should always be sought.

- ***Physical, contractual and other legal arrangements need to be sufficiently well understood to be able to confirm whether or not a Class Exemption is available.***

6.2.1 Summary

The Electricity Act 1989 prohibits the generation, distribution or supply of electricity without a licence, unless the person carrying out that activity benefits from a specific exemption granted by the Secretary of State or falls within a ‘Class Exemption’.

Carrying on a prohibited activity (without a licence or exemption) is a criminal offence:

- even though it can sometimes be difficult to determine with a high degree of certainty whether a particular activity is compliant or non-compliant;
- regardless of the intentions of any person committing an offence, technical non-compliance identified by a professional advisor in a transactional context can trigger an obligation on the advisor to notify potential ‘proceeds of crime’ or face potential personal criminal liability him/ herself.

Class exemptions are granted under the Electricity Act (Class Exemptions from the Requirement for a Licence) Order 2001 covering, amongst other things:

- generation, distribution or supply below certain thresholds;
- distribution or supply involving only limited or no domestic supplies;
- generators making on-site supplies or supplies over private wires; and
- re-sellers of electricity.

However, some of the above categories are subject to difficult to follow definitions and complexity.

6.2.2 The Electricity Act (Class Exemptions from the Requirement for a Licence) Order 2001

The Electricity Act (Class Exemptions from the Requirement for a Licence) Order 2001[50] (**Class Exemption Order**) provides exemption for a number of classes of generation, distribution and supply activities, often referred to as the "Class Exemptions".

In this guidance, we focus only on those exemptions frequently relevant in the context of electricity generated with heat and generation from renewables– this being generally smaller, decentralised generators, with electrical connection to a distribution network but where there may be a desire to make electricity supplies to local customers. Careful attention should be paid to the precise wording of any Class Exemption being relied on, as set out in the Class Exemptions Order, since these guidance notes only give summaries of the relevant exemptions here***. It is also important to note that an activity might fall under more than one Class Exemption but, for example, exemption in respect of supply can only be claimed under one of the supply exemptions.*** The coverage of multiple exemptions cannot be added together.

6.2.3 Generation exemptions

There is only one exemption likely to be relevant.

Class A: small generators – this exempts those who:

- generate less than 50MW from a generating station of less than 100MW declared net capacity; or otherwise
- generate less than 10MW.

Each generating plant is considered separately[51].

A person is treated as generating electricity if they are actually generating electricity or are capable of generating electricity but for temporary maintenance[52].

This should be sufficient to exempt most local authority heat network CHP installations or other renewable generating plant.

6.2.4 Distribution exemptions

The Electricity Act defines:

- electricity "*distribution*" as follows:

  "distribute by means of a distribution system, that is to say, a system which consists (wholly or mainly) of low voltage lines and electrical plant and is used for conveying electricity to any premises or to any other distribution system"

- "low voltage" as 132kV or lower in England and Wales or under 132kV in Scotland.[53] Consequently, this sets the limits of what is distribution voltage for the purposes of the Electricity Act.

There are three distribution Class Exemptions, each of which is of relevance (although see also 6.2.6 Understanding 'self-supply'):

Class A: small distributors – this exempts those who distribute less than 2.5MW of electrical power for the purpose of giving (or enabling) supply to domestic customers. This 2.5MW domestic supply limit is applied on an aggregate basis across sites operated by a person or operated by any member of the same corporate

[50] As amended
[51] However, if two generating plant of the same technology are located on the same site, they may be deemed to be one larger plant.
[52] Regulation 2(2)(d) of the Class Exemption Order.
[53] It is important to note that the term "low voltage" has many different uses and definitions throughout the electricity industry. The definition presented here is relevant for Electricity Act purposes and distinguishes between *distribution* and *transmission*.

group[54]. However, it would exclude distribution in another part of a corporate group, if that falls under the Class B distribution Class Exemption, described below.

Class B: on-site distribution – this exempts those who distribute:

- any amount of electricity for commercial purposes; and
- not more than 1MW of electrical power for the purpose of giving (or enabling) a supply to domestic consumers from a generating station embedded in the same distribution system.

This Class Exemption allows for electricity to come from other ‘standby’ sources on a temporary basis when the generator is not actually producing the power itself or is producing less than normal due to generating plant outages, etc. However, it does not allow ‘top-up’ above the normal level of output of the generating station. So, for example, for a 500kW generating plant, it only allows up to 500kW of distribution for domestic supply, This limits the value of this particular Class Exemption.

Class C: distribution to non-domestic consumers – this exempts those who undertake any amount of distribution to commercial customers only. This exemption is not available if the distribution network is used at any time to distribute any electrical power at all for the purpose of giving (or enabling) a supply to domestic consumers.

6.2.5 Supply exemptions

The Electricity Act 1989[55] defines “supply” as follows:

> *“supply” in relation to electricity, means its supply to premises in cases where—*
>
> *(a) it is conveyed to the premises wholly or partly by means of a distribution system, or*
>
> *(b) (without being so conveyed) it is supplied to the premises from a substation to which it has been conveyed by means of a transmission system,*
>
> *but does not include its supply to premises occupied by a licence holder for the purpose of carrying on activities which he is authorised by his licence to carry on*

Consequently, physical delivery of electricity via a distribution or transmission system is necessary to constitute ‘supply’ but, it excludes electricity delivered to a person holding a generation, distribution or supply licence for purposes ancillary to their licensed activity.

Class A: small suppliers – this exempts:

- those who only supply electricity which they generate themselves; and
- the amount of electricity they supply is less than 5MW and not more than 2.5MW of that is to domestic customers.

This 5MW/2.5MW supply limit is applied on an aggregate basis across sites and across a corporate group [56]. Therefore, it is only available to permit very limited supply activity. Also, it does not explicitly permit back-up or top-up supply[57], arguably rendering the exemption of little practical use.

Class B: resale – this exempts those who only supply electricity:

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[54] The Class Exemptions Order refers to bodies corporate ‘associated’ with each other because of a parent-subsidiary relationship between them or having a shared parent, in terms of the Companies Act 1985 (which is broadly the same as the definition under the Companies Act 2006)

[55] Section 4

[56] The meaning of corporate group is explained in footnote [53].

[57] Regulation 2(2)(d) of the Class Exemption Order provides that a generator is to be treated as generating electricity if he is actually generating electricity or is capable of generating electricity but for temporary maintenance. It is debatable whether this permits back-up under the Class A supply exemption.

- which is supplied to them by a licensed supplier or;
- by someone exempted under Class C (see below); or
- which they generate themselves; or which
- is supplied to them by someone exempted under another Class Exemption if:
    - their supply from a licensed supplier or Class C exempted supplier is unavailable to them for reasons beyond their control; or
    - their own generating plant is being tested.

However, whilst this Class Exemption permits any amount of on-supply from a licensed supplier, further limitations apply to the on-supply of Class C exempted electricity. The limbs appear to be cumulative and, so, permitting supply of a combination of own generation and imported licensed supplies, with similar coverage to the Class C exemption (discussed below). However, the following provisos to use of Class B further complicate matters:

If more than 10% of the Class C exempted electricity received by the supplier at any premises in the previous year was on-supplied, the Class B exemption is not available. In the first year of on-supplying Class C exempted supplies, the supplier must have a reasonable basis for expecting that on-supplies will not exceed 10% of the amount of Class C exempted supply that they will receive at those premises in the coming year. And, no more than 250MWh of Class C exempted electricity received at any premises in any year may be on-supplied to domestic consumers. This limits the use of Class B.

NB: For any project, specialist legal advice should be sought, taking into account the specific circumstances of the project and testing them against the wording of what appear to be the most relevant exemptions.

Class C: on-site supply – this exempts those who only supply electricity which:

- they generate themselves or which they generate themselves together with electricity which they receive from a licensed supplier; and
- is consumed by eligible consumers.

The Class C supply exemption sets out a list of eligible consumer types by reference to consumption scenarios. Many of these are overlapping and complex. However, they can be loosely summarised as follows:

- a "**single consumer**" or an "**onsite qualifying group**" [this is a single consumer or consumers in the same corporate group] that, in either case:
    - occupies the same site as the generating station; and
    - consumes all the electricity at that premises (other than where they make Class B exempt on-supplies);
- "**additional group consumers**" each of whom:
    - occupies the same site as the generating station or receives the electricity over "private wires"; and
    - consumes all the electricity at those premises (other than where they make Class B exempt on-supplies); and
    - total power supplied is less than 100MW, of which not more than 1MW is for domestic supply;
- a "**remote consumer**" or "**remote qualifying group**" [this is a single consumer or consumers in the same corporate group] that, in either case:
    - receives at least one third of the output of the generating station at premises they occupy on the same site as the generating station or which is connected by private wire;
    - consumes all the electricity at those premises (other than where that they make Class B exempt on-supplies);
- additional group consumers consuming less than 100MW (by which, it is assumed, at peak load) together with any of a single consumer, an on-site qualifying group, a remote consumer or a remote qualifying group (or any combination of them);

- any other person where the provision of the output of the generating station does not amount to the supply of electricity[58].

To understand the above, the following definitions are also important:

- "**private wires**" means electric lines owned by—
  - the supplier in question;
  - consumer who receives a supply from the supplier in question from the generating station;
  - the owner, lessor or lessee of the generating station or of one of the premises to which a supply is made by the supplier in question; or
  - any of the persons described above jointly with any other of the persons described above,

  provided that the owner of those wires is not a licensed distributor.[59]
- "**site**" is not defined nor are "**premises**" or "**same site**" (in the context of consumers) but some guidance may be drawn from the treatment of generating sets being on the "**same site"** as each other if they are—
  - on the same premises;
  - on premises immediately adjoining each other; or
  - on premises separated from each other only by a road, railway or watercourse or by other premises occupied by the consumer in question, by any other person who together with that consumer forms a qualifying group, or by the person seeking to take advantage of the relevant generation or supply exemption.[60]

From the above, it should be apparent that the Class C supply exemption is potentially very useful for operators of generating plant which they wish to use to meet some of the electricity demand of customers on the same site or connected by private wires. However, it should be noted that understanding what is and what is not exempted under Class C is far from straightforward and requires a good understanding of property ownership, corporate group structures, commercial supply arrangements and the point or points at which "supply" actually takes place.

NB: For any project, specialist legal advice should be sought, taking into account the specific circumstances of the project and testing them against the wording of what appear to be the most relevant exemptions.

6.2.6 Understanding 'self-supply'

Self-supply has different meanings in different contexts.

, It is important first to determine whether any given self-supply scenario gives rise to any 'supply' or 'distribution' in terms of the Electricity Act definitions with the consequential requirement to hold a licence or fall within an exemption. Each scenario needs to be assessed on the facts.

Two different example scenarios are given below.

Scenario A: a generator generates electricity on one premises and consumes that electricity themselves on the same premises. They may be neither distributing that electricity nor supplying that electricity within the definitions given by the Electricity Act. Where that is the case, neither a licence nor an exemption is needed in respect of the carriage or delivery of that electricity.

Scenario B: a generator generates electricity on one premises and conveys it at 11kV to multiple consumers on an industrial site. There is low voltage 'distribution' and, because of that, there is also 'supply' for the purposes of the Electricity Act. Both the distribution and the supply must either be licensed or fall within an exemption. However, parasitic load of the generating station (that is, electricity consumed within the process of

[58] The provision of electricity that is not "supply" for Electricity Act purposes does not need to be licensed or benefit from an exemption.
[59] This means that it is essential to understand ownership of the full length of any 'private wire' connection and all relevant supply arrangements.
[60] Again, this means that the availability of the "same site" limb of the Class C supply exemption can only be properly assessed following enquiry into land ownership.

generating) would not be delivered to premises nor distributed so neither a 'supply' nor 'distribution' arises in respect of that parasitic load and it requires neither a licence nor an exemption.

Certain other legislation uses the term 'self-supply' (or similar terms) but may or may not define this by reference to the Electricity Act definitions.[61] Therefore, it does not have a consistent meaning or capture across legislation and care should always be taken when assessing the treatment of self-supply.

6.2.7 Specific licence exemption

It is possible to apply for a specific licence exemption rather than relying on the Class Exemptions described above. This might be justified, for example, where the nearest Class Exemption criteria are not met or it is foreseeable that applicable thresholds will be exceeded over time. The Ofgem register of exemptions granted shows that specific exemptions tend to be granted to generation scenarios rather than supply. Published guidance by BEIS on licence exemptions[62] confirms that generation exemptions will generally only be granted to stations under 100MW and that distribution and supply exemptions will generally not be deemed appropriate.

There is no prescribed procedure for applying for a specific exemption, but it will be necessary to apply in writing to the Secretary of State specifying the nature and extent of the exemption sought, providing justification and demonstrating that there is no material risk to the wider competitive market arising. The process of applying for a specific exemption might be justified, for example, where the Class Exemption criteria are not met or it is foreseeable that applicable thresholds will be exceeded over time.

6.2.8 Maximum Resale Price

The resale of electricity to domestic consumers must not exceed any maximum sale price specified by Ofgem[63]. At present, this is the same price as the re-seller paid for it, including any standing charges. The reseller is not entitled to recover the costs of running an electricity system through the charges made for electricity, however is free to choose how these are separately recovered (for example as service charges or as part of an accommodation charge).

The Maximum Resale Price rules only apply to electricity resold for domestic purposes and does not apply to electricity resold for industrial or commercial use.

6.2.9 Criminal liability

The Electricity Act 1989[64] (**Electricity Act**) applies to the generation, distribution, transmission and supply of electricity (and certain other activities). It prohibits[65] the carrying out of any of these activities without a licence unless the activity:

- has been granted a specific exemption by the Secretary of State; or
- falls within one of a number of Class Exemptions (see further below).

Breach of this Electricity Act prohibition is a strict liability criminal offence. That means that being *mistaken* in the belief that an activity is exempt is not a defence to a charge that the prohibition has been breached.[66] This is particularly problematic when the lines between what is exempt and what is not are not clear, as is the case with some of the Class Exemptions. So, it is possible that a view may be taken and, subsequently, for that view to be found incorrect *at law*.

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[61] For example, the term 'self-supply' is used in the CRC Energy Efficiency Order 2013 but the intended capture of the concept is not limited to scenarios that constitute 'supply' under the Electricity Act.
[62] Department of Energy & Climate Change: Electricity Generation, Distribution and Supply Licence Exemptions: Frequently Asked Questions (June 2013)
[63] See Ofgem Maximum Resale Price Provisions Decision Document January 2002 (07/02) and Ofgem Guidance: The resale of gas and electricity – guidance for resellers (effective from 1 January 2003, updated 14 October 2005)
[64] As amended
[65] Electricity Act, section 4
[66] Although it may go towards mitigation on conviction.

This is also a problem because, once a breach has been identified in a commercial setting, it is conceivable that an element of profit (whether through greater revenue earned or lower costs incurred) is attributable to the non-compliant activity relative to compliant activity. Any such profit might be considered *proceeds of crime* under the Proceeds of Crime Act 2002,[67] giving rise to reporting and other obligations on professional advisors and financiers under the Money Laundering Regulations 2007.

Local authorities should proceed with caution when undertaking any activities relating to electricity generation, distribution and supply and should always:

- take legal advice;
- take a conservative view of the scope of the Class Exemptions where ambiguities or difficulties of interpretation arise.

6.3 Restrictions on the ability of a local authority to sell electricity

Overview:

Local authorities are subject to additional restrictions on their powers to sell electricity, compared to others.

Either the Local Government (Miscellaneous Provisions) Act 1976 or the Localism Act 2011 is typically used by a local authority to authorise its participation in the sale of electricity. There is a small difference in what each permits.

Neither route permits the sale by a local authority of electricity unless it has been generated with heat or from renewable sources. This may require local authorities to put in place additional commercial arrangements, compared to others, in order to ensure that top-up, back-up and balancing power is sourced from renewable sources or, where the Localism Act 2011 is relied on, from CHP.

Relevance to CHP:

- ***Local authorities should choose the right power for their involvement in the sale of electricity.***
- ***Local authorities may need to put in place additional commercial arrangements, to secure that top-up, back-up and balancing power is sourced from renewables or CHP, in order to comply with a legislative restriction on the types of electricity they can sell.***

6.3.1 Local Government Act 1976

Section 11 of the Local Government (Miscellaneous Provisions) Act 1976 (**LGA 1976**) permits a local authority to generate heat and electricity and to sell electricity which it has generated with heat.

However, section 11(3) of the LGA 1976 then prohibits local authorities from selling electricity unless produced in conjunction with heat (without specifying who generated it), as follows (emphasis added):

> *11. Production and supply of heat etc. by local authorities.*
>
> ……….

[67] As amended

(3) Except in such cases as may be prescribed, a local authority shall not be entitled to sell electricity which is produced otherwise than in association with heat.

This restriction was partially lifted by the Sale of Electricity by Local Authorities (England and Wales) Regulations 2010 (**LA Regs 2010**). The LA Regs 2010 prescribes that local authorities may also sell electricity generated from any of the following renewable sources: (a) wind, (b) solar, (c) aerothermal, (d) geothermal, (e) hydrothermal and ocean energy, (f) hydropower, (g) biomass, (h) landfill gas, (i) sewage treatment plant gas, and (j) biogases.

Therefore, if a local authority uses the LGA 1976 as the justification to sell electricity, it is free to sell electricity in its own name or through a Special Purpose Vehicle (SPV), but it is *ultra vires* a local authority's powers to sell any electricity other than:

- electricity which it [or its SPV] has generated itself in association with the production of heat (i.e. its own CHP); and
- electricity which it [or its SPV] has generated itself from any of the listed renewable energy sources; and
- electricity which it [or its SPV] has acquired from someone else but which was generated from any of the listed renewable energy sources[68].

This means that:

- any electricity sourced from a third party generator must be renewable; and
- any back-up or top-up power or power bought for balancing purposes must be renewable electricity.

This will apply equally to any electricity purchased from another licensed supplier or on the wholesale market. However, electricity should be considered to be from renewable or CHP sources if it was procured under a contract that guaranteed the origin was from a relevant source within the list of exemptions, for example by provision of ROCs/REGOs. Local Authorities should, therefore, ensure that the contracts they enter into for the purchase of power (including back-up and top-up supplies) warrant and evidence the appropriate origin of the electricity.

Further information is provided in the DPD Guidance section on: Powers, Procurement and State Aid.

6.3.2 Localism Act 2011

If, on the other hand, a Local Authority uses the Localism Act 2011 as its justification for selling electricity, rather than LGA 1976, then:

- it can sell any electricity save as prohibited by legislation – the section 11(3) LGA 1976 restriction still applies (as modified by the LA Regs 2010[69]); and
- it must set up a SPV.

Further information is provided in the DPD Guidance section on: Powers, Procurement and State Aid.

There is a fine distinction in that the LA 2011 is slightly wider and permits the Local Authority (through its SPV) to sell electricity generated from renewables or with heat by a third party.

This means that, using the LA 2011, a Local Authority must undertake that activity through an SPV and only sell:

- electricity which it or its SPV or a third party has generated in association with the production of heat; and
- electricity which it or its SPV or a third party has generated from any of the listed renewable energy sources.

[68] How the permissive wording of the LA Regs 2010 fits with the restrictive wording of s.11(3) of the LGA 1976 and the narrow permissive wording of s.11(1) of the LGA 1976 is somewhat ambiguous but it is assumed to permit sale by local authorities of electricity generated by third parties from eligible renewable sources.
[69] In the context of the wider permissive wording of the LA2011, the wording of the LA Regs 2010 is not ambiguous.

However, this still requires that any back-up or top-up power or power bought for balancing purposes must be renewable power or from CHP.

6.4 Powers and restrictions under other local acts and byelaws

It is outside the scope of this guidance document to review all possible local legislation and byelaws but readers should be aware that such legislation[70] may exist and permit or even further restrict certain activity relevant to the operation of district heating networks and sale of heat and electricity.

6.5 State aid and the sale of electricity

Overview:

As public bodies, local authorities are subject to restrictions on what they can fund and how they fund it without falling foul of State aid rules.

Relevance to CHP:

Local authorities should take advice to avoid breaching State aid rules when:

- ***funding or providing other support towards the set-up or operation of a district heating scheme, CHP or heat or electricity supply business;***
- ***setting a strategy that involves selling heat or power at below market rates.***

6.5.1 State aid

If certain conditions are met, State aid that distorts or threatens to distort competition by favouring certain undertakings, is illegal[71].

State aid can occur whenever state resources are used to give selective assistance to an undertaking. An 'undertaking' is any organisation engaged in economic activity and can include non-profit organisations, charities and even public bodies. An entity providing energy (including heat) under discretionary powers will virtually always be an undertaking for State aid purposes.

State aid will be relevant to all district heating projects involving public authorities or the use of public funds (including European funding) or resources as any agreement involving state resources and an undertaking – even a simple contract for services - can attract State aid considerations. Different considerations will apply depending on the structure used and the parties involved.

6.5.2 External funding

Firstly, any external funding (being from state resources) injected into a scheme could give rise to State aid considerations and the funding bodies will often seek assurances that the funding will be used in a State aid compliant manner. Local authorities will not only need to satisfy themselves that the project is State aid compliant, but also to satisfy their funding bodies. This will often involve obtaining legal opinions confirming the State aid position addressed to both the funding body and the local authority. Where compliant State aid

[70] For example, aspects of the London County Council (General Powers) Act 1949 are still in force and may be used by qualifying authorities but subject to specific conditions set out in that legislation.
[71] Article 107(1) of the Treaty on the Functioning of the European Union

has been obtained, this does not automatically preclude further State aid being utilised in a compliant manner in the same scheme, although different funding sources may apply their own conditions restricting the use of separate external funding and consideration would need to be given to the cumulative position. These considerations will presumably apply in relation to the deployment of the £300m allocated by the Government to district heating through BEIS.

6.5.3 Joint Ventures and Wholly Owned Companies

State aid issues will clearly be relevant where a private sector partner is brought on board to help deliver the project, but can also apply where a joint venture partner is another public authority. This is because the definition of an 'undertaking' for State aid purposes is based upon the recipient's activities, not their status as a public or private body. This means that aid to public authorities offering goods or services on a market must be considered just as carefully as aid to private sector bodies.

Similarly, a company or other entity wholly owned by the local authority which undertakes any commercial elements of a project is likely to be an undertaking and so any funding or support provided to such an entity will also need to be considered for State aid purposes. See the next section for examples of potential aid.

6.5.4 Downstream aid to third parties

If state resources are used to generate electricity which is then sold at below-market rates (i.e. below the rates the recipients would be able to obtain elsewhere on the available market), the sale of this energy to undertakings has the *potential* to be illegal State aid to those undertakings. When developing a commercially attractive offer, for example including discounted rates on price, care will need to be taken to avoid illegal State aid. It is important to note that private individual consumers are not usually undertakings for State aid purposes and below-market rates to these consumers will not be illegal State aid. However, this does not mean that the aid could be granted to an intermediary just because the end user would be a private resident. For example, if a social landlord which was an undertaking obtained below-market rates and obtained a commercial benefit as a result, the fact that the end user would be private residents would not eliminate any State aid given to the social landlord. There may, however, be other routes to compliance, for example by passing through the benefit of the below market rates and ensuring no residual benefit is retained by the social landlord.

6.5.5 Exemptions

Where the presence of state aid has been identified and its potential quantum assessed, it will be necessary to either identify an appropriate exemption or obtain approval from the European Commission by notifying it of the proposed scheme through the Department for Business, Innovation & Skills.

A. De Minimis Regulation

Where only a small quantum of aid is to be provided, it may be possible to rely on the De Minimis Regulation. Further guidance on the application of the De Minimis Regulation is available at paragraph 8 of the Guidance available from BEIS. Given the low threshold for the application of this exemption, it is only likely to be useful for low levels of aid to third parties rather than delivery partners.

B. General Block Exemption Regulation

The current General Block Exemption Regulation contains several exemptions permitting aid for specific projects. See page 8 of the BEIS Guidance. Article 40 provides exemption for investment aid for 'high efficiency co-generation' (high efficiency combined heat and power). Article 46 provides exemption for investment aid for energy efficient district heating and cooling systems. If aid falls within the scope of either of these Articles, it will be deemed to be aid which is compatible with Articles 107-109 Treaty on the Functioning of the European Union (TFEU) and, so, will be exempt from the requirement to give prior notification to the Commission.

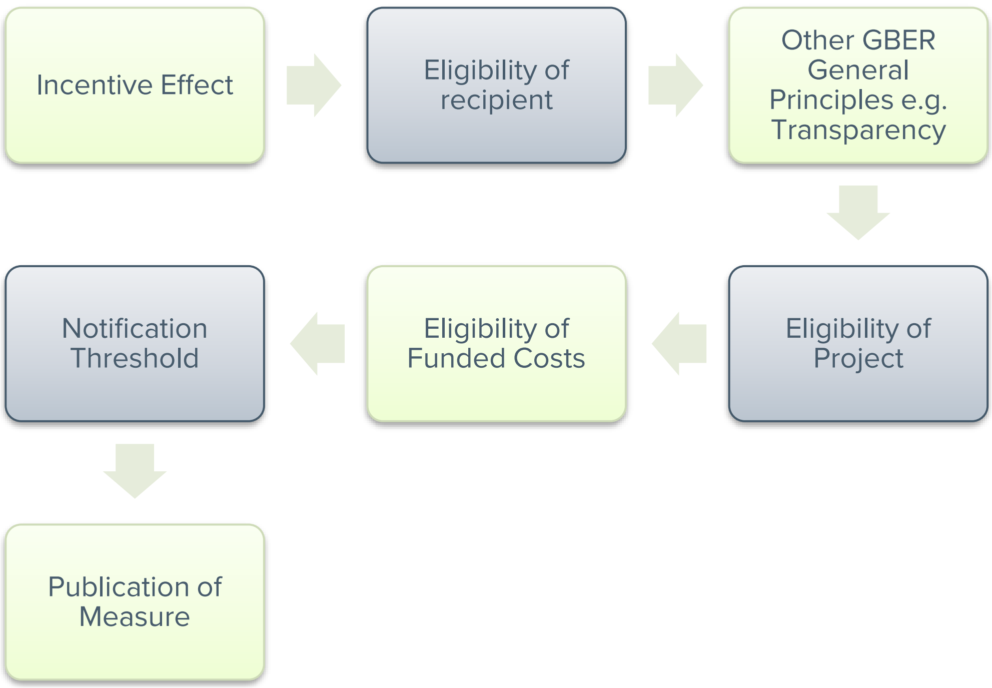
Local authorities seeking to rely on Article 40 or Article 46 to ensure State aid compliance will need to address each of the different requirements of these Articles. The elements are split into two categories: (i) general requirements which apply to all or the majority of exemptions under General Block Exemption Regulation (GBER), and (ii) specific requirements which only apply to the Article 40 or the Article 46 exemption.

GBER General Principles: GBER sets out a series of general principles which apply to the majority of exemptions. These are set out at Articles 1-12. The key general requirements are set out below but care should be taken to review all the requirements in full.

Incentive Effect (Article 6): Prior to any '*aid instrument*' (i.e. the legal agreement under which the recipient becomes entitled to the aid) coming into effect, the recipient must formally request the aid in order to demonstrate that the project would not proceed at the same level, or at all, without the aid. The information to be contained in the application varies according to the size of the recipient. See Article 6 of GBER for further detail. In reality, the following stages will be considered prior to the request being made to ensure the exemption is available but the request will be the first 'formal' stage in the process.

Eligibility of Recipient (Article 1): the funder must ensure that the recipient (even if itself) is eligible to receive funding through GBER. GBER contains a number of restrictions at Article 1 - for example, aid cannot generally be provided to recipients which are in financial difficulty or active in certain sectors.

Transparency (Article 5): it must be possible to calculate the precise amount of aid under GBER. Usually this means that funding cannot be provided which covers all of the costs of a project up to a certain date or completion if the amount of those costs are uncertain. Instead, the deployment of aid to such costs must be for a capped amount or fixed in advance. Similarly, loan facilities and guarantees must be of a maximum or fixed duration.



GBER Specific Requirements – Article 46: As well as the general requirements above, a number of specific requirements apply to Article 46. These are summarised below.

Eligibility of project: Article 46 only applies to funding for the production plant and/or distribution network (including related facilities) of energy efficient district heating and cooling systems. The system must satisfy the requirements of Article 2(41) and (42) of Directive 2012/27/EU on energy efficiency, set out below.

Production Plant: Eligible costs will be "extra costs needed for the construction, expansion and refurbishment of one or more generation units to operate as an energy efficient district heating and cooling system compared to a conventional production plant. The investment shall be an integral part of the energy efficient district heating and cooling system." The value of the aid must be no more than 45% of these costs. This percentage can be increased for small and medium enterprises. The Commission has published a User Guide setting out how to establish whether an entity is a Small or medium-sized enterprise (SME).

The financial modelling used to compare a district heating system with a counterfactual may prove useful in establishing the base costs for the purposes of establishing the '*extra costs*' referred to above.

Distribution Network: Eligible costs will be the total costs of the installation of the distribution network but not the operating costs. The value of the aid is limited to the difference between the investment costs of network installation and the operating profit (i.e. the *viability gap*). For the purposes of GBER, the operating profit is defined as:

"*the difference between the discounted* revenues *and the discounted operating costs over the relevant lifetime of the investment, where this difference is positive. The operating costs include costs such as personnel costs, materials, contracted services, communications, energy, maintenance, rent, administration, but exclude, for the purpose of this Regulation, depreciation charges and the costs of financing if these have been covered by investment aid*".

Since assessing the cost of installation and measuring the operating profit occur at very different times, and are subject to very different degrees of certainty, the value of the aid can be established in advance on the basis of projections or retroactively through a claw-back mechanism. It is vital to ensure that there is no double-counting, so the same eligible costs cannot be met by '*operating aid*' and '*investment aid*' or by funding through different exemptions.

The distribution network and the production plant should be considered and calculated separately, as confirmed in the Commission's General Block Exemption Regulation Frequently Asked Questions.

Notification threshold: The level of aid which can be provided under Article 46 is capped at €20,000,000 in respect of any one project. If the proposed aid exceeds this, prior approval will need to be obtained from the European Commission through BEIS.

GBER Specific Requirements – Article 40: As well as the general requirements above, a number of specific requirements apply to Article 40. These are summarised below.

New capacity: The aid may only be granted to new or newly refurbished capacities.

Primary energy savings: Primary energy savings must be delivered compared to separate generation of heat and power, to levels specified in the Energy Efficiency Directive (2012/27/EU).

The eligible costs are the extra investment costs for the equipment needed for the installation to operate as a high-efficiency cogeneration installation, compared to conventional electricity or heating installations of the same capacity or the extra investment cost to upgrade to a higher efficiency when an existing installation already meets the high-efficiency threshold.

Aid intensity: The aid intensity must not exceed 45 % of the eligible costs. The aid intensity can be increased by 20% for aid granted to small undertakings or by 10% for aid granted to medium-sized undertakings.

The aid intensity can be increased by 15 % for investments in assisted areas fulfilling the conditions of Article 107(3)(a) of the Treaty and by 5% for investments in assisted areas fulfilling the conditions of Article 107(3)(c) of the Treaty.

GBER post-award publication (Articles 9 and 11)

Once the aid instrument has been entered into, the funder must log certain details about the aid measure with the European Commission through BEIS. The information to be provided varies according to the total value of the aid and is set out in Articles 9 and 11 of GBER. This includes a summary of the aid measure in the form set out in Annex II of GBER, the full text of the aid measure, and where the aid award exceeds €500,000, the additional information set out in Annex III of GBER. The information must be logged within 20 working days of the aid measure coming into effect and the funder must publish the aid measure on the internet.

C. Market Economy Operator Principle (MEOP)

Generally, loans, guarantees and contracts for goods, works or services entered into at market rates will comply with the MEOP.

If an undertaking in receipt of State aidcan demonstrate that a private operator operating under normal market economy conditions would act in the same way, then the action taken will not result in illegal State aid. This is the Market Economy Operator Principle ("*MEOP*"). BEIS' detailed guidance on State aid deals with MEOP at page 16.

To rely on the MEOP, it is necessary to show that an '*ordinary*' market operator, in the same position as the undertaking, would enter into the proposed arrangements. It is vital that, when assessing this, only private considerations (which will primarily focus on financial considerations, but it is also possible to include long term strategic considerations) are taken into consideration. '*Public*' considerations, such as social objectives (for example, eliminating fuel poverty) or the promotion of regeneration or economic growth should be ignored for the purposes of this principle. If the undertaking owns land with development potential which the network will feed into then the commercial benefits of linking to the network could be taken into account, depending on the contractual structure.

In practice, MEOP will only be useful where the proposed district heating scheme would be seen as sufficiently attractive to a private investor (i.e. would generate sufficient revenue) to warrant the investment the funder is proposing to make. In order to demonstrate compliance with MEOP, a funder (or recipient on the funder's behalf) would need to have prepared a business plan which demonstrated that revenue from the sale of heat, connection charges, sale of electricity or any other products and services would be sufficient to warrant the risks assumed on a commercial basis. Expert advice is often obtained from commercial advisers as to what a private investor would look for in a scheme and this would go a long way in defending the funder's and recipient's positions in the event of a challenge or investigation.

D. Services of General Economic Interest (SGEI)

SGEI are services which the market does not naturally provide to the extent or at the quality required by an individual Member State and which is in the general interest (i.e. open to the public). There is no prescribed list of SGEI and it is left open to each member state to determine which services will be SGEI. The provision of gas and electricity at a national level has the potential to qualify as an SGEI but the position is less certain in relation to local district heating systems.

Decision SA.31261 (2011/N) of the Commission suggests that, in limited circumstances (which included a statutory obligation on the body in question to provide affordable heat to residents), the provision of heat through a district heating system can qualify as an SGEI. However, care should be taken in relying on this decision and it may be prudent to obtain Commission approval before proceeding on this basis, as the German authority involved did.

If a service does qualify as an SGEI, then the funding of this service by the state can qualify as legal State aid if a number of criteria are met, including:

- the recipient undertaking must have public service obligations and the obligations must be clearly defined;
- the parameters for calculating the compensation must be objective, transparent and established in advance
- the compensation cannot exceed what is necessary to cover all or part of the costs incurred in the discharge of the public service obligations, taking into account the relevant receipts and a reasonable profit;
- where the undertaking which is to discharge public service obligations is not chosen pursuant to a public procurement procedure which would allow for the selection of the tenderer capable of providing those services at the least cost to the community, the level of compensation needed must be determined on the basis of an analysis of the costs of a typical well-run company

These requirements are often referred to as the 'Altmark Criteria'.

For further information on SGEI see Chapter 7 of the BEIS Guidance. The provisions governing the funding of SGEI are set out in the following documents:

Document	Applicability
Communication from the Commission on the application of the European Union State aid rules to compensation granted for the provision of services of general economic interest (2012/C 8/02)	Sets out the general requirements required for funding of SGEI to be legal State aid
Commission Decision on the application of Article 106(2) of the Treaty on the Functioning of the European Union to State aid in the form of public service compensation granted to certain undertakings entrusted with the operation of services of general economic interest (2012/21/EU)	Permits aid for funding SGEI up to €15M per annum without prior notification to the Commission
Communication from the Commission on the European Union framework for State aid in the form of public service compensation (2012/C 8/03)	Sets out criteria for assessment of larger SGEI funding arrangements requiring prior notification to the Commission
Commission Regulation 360/2012 on de minimis aid granted to undertakings providing services of general economic interest	Sets out an increased de minimis threshold for undertakings providing SGEI (€500,000)
Financial Transparency Directive 2006/111/EC	Sets out transparency requirements for certain recipients of SGEI funding (for example additional accounting requirements)

E. Notification to Commission: Process, timescales and principles

In the event that an appropriate exemption cannot be identified, the funder will need to either revisit its proposals or obtain Commission approval for the project. The process for notifying the Commission of the proposals is lengthy and must be conducted through BEIS as the process is conducted between the member state (the UK) and the Commission. The Commission will only approve projects which it considers to be compliant with the treaty principles and, in the case of cogeneration and district heating, the Commission will usually consider the proposals against the Environmental Aid Guidelines. Although there is some overlap (e.g. that a district heating scheme is to be energy efficient) between the Environmental Aid Guidelines and Articles 40 and 46 of GBER, the requirements are different, so it is possible for projects which fall outside the scope of Articles 40 and 46 to comply with the Environmental Aid Guidelines.

The process for notification is set out in the BEIS Guidance at page 59 and the BEIS recommends allowing a period of at least 6-12 months for any notification process. This is a minimum as several factors, including third parties objecting, can lead to significant delays in the process. Notification will usually only be a last resort due to the timescales involved.

State aid analysis might be made on a case by case basis, depending on how a scheme is being structured. There may be a risk of generating State aid and an approach needs to be identified to deal with issues to ensure no unlawful aid is being provided.

6.5.6 Further guidance available

Further guidance is provided in the BEIS Guidance section on: Powers, Procurement and State Aid in respect of the identification and quantification of aid and exemptions that may be available.

7 Commercial implications of Routes to Market

What is covered in this chapter?

This chapter examines the commercial implications of a chosen route to market for the electrical output from an embedded generator such as a CHP site. This includes estimates of revenues that can be expected for the output from an embedded generator and how these will vary depending on various factors. The following topics are covered in this chapter:

- Identification of the variables that may impact on the revenue stream for an embedded generator.
- A baseline revenue estimate for a 1MW embedded generator using a standard PPA agreement.
- A comparison of the revenue uplift or reduction that can be expected under the alternative routes to market compared to the baseline.
- The impact of the variables on the revenue streams.

7.1 Background

The route to market chosen for an embedded generator, such as a CHP, can have a significant impact on the revenue received. This chapter looks at the factors that can impact on the revenue earned through each route to contract and any impact it may have on the volatility of the revenue stream or the costs associated with each route. It should be noted that the revenue estimates provided in this section are illustrative and based on a number of assumptions. The actual revenue that will be received by an embedded generator will vary from the values estimated in this section.

7.2 Regulatory Risk

The future value of the potential revenue streams available to a generator will change as market prices move and as changes to the regulatory environment are implemented. The regulatory environment for embedded generation is currently under review by Ofgem and National Grid and may have a substantial impact on future revenue streams, particularly in the area of embedded benefits. ***Stakeholders should also note the recent decision[72] on Triad benefit issued by Ofgem on 22 June 2017 which will reduce the level of the residual element of the Triad benefit for embedded generation to close to zero when it is phased in from April 2018**. **Ofgem has also highlighted "behind the meter generation" as a priority issue for them.***

When reviewing the forecast revenues contained in this section it is important to have an understanding that they may change in the future. A detailed explanation of future regulatory change is contained within Chapter 10.

[72] Impact Assessment and Decision on industry proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators

7.3 Sources of income

The key income streams that may be available for embedded generation are set out below:

- Wholesale market
- Embedded benefits[73]
- Capacity market
- Ancillary Services
- Renewable subsidies

The value of these revenue streams will depend on a number of variables which are discussed below.

7.3.1 Running Regime

The running regime of a plant is a fundamental driver of the electricity revenue earned. Under normal running conditions an embedded plant can expect to operate when the total income is greater than the marginal cost of production. Consequently, the wholesale price combined with the other revenue streams will determine whether a plant exports in each half hour (settlement period). An additional consideration is the operating characteristics of the plant, particularly how flexible it can be in terms of ramping up and down at short notice, and whether the plant can run in a flexible operating mode. For a CHP, additional constraints exist as the plant is also providing heat services to end customers. Where heat storage is installed, this can disconnect heat demand and supply and allow for a more flexible running regime with potentially higher revenues.

Where flexibility exists, the alternative running regimes need to be assessed to look at the overall cost (including the cost of providing the heat from backup boilers or using heat storage) and revenue generated. Additional payment may be possible where the plant can participate in the ancillary services (also known as the balancing services) market. However, it will need to be able to meet the technical requirements of the System Operator as specified for each service. More detail on the revenues and requirements under ancillary services contracts are detailed in Chapter 9

The running regime of a plant will impact the revenue streams under all revenue categories except for the capacity market. Where a site has a capacity market contract, it will receive a payment on a monthly basis, regardless of the volume of power exported. The only exception to this is where a capacity market notice is issued which requires the site to be exporting at full capacity and if the site does not export at this time, a penalty payment will be incurred see 9.1.2.

7.3.2 Location

The location of the site will determine the level of embedded benefits that can be accrued. This includes the value of the Triad benefit that is applied and the level of the transmission losses that will vary by DNO area from April 2018 (under change proposal P350[74]).

The embedded benefits at the distribution level are DNO specific and will therefore also vary by DNO area. This includes distribution losses and Distribution Use of System charges (DUoS).

7.3.3 Voltage of Connection

A further consideration is the connection voltage, which determines the embedded benefits that accrue at the distribution level. These can be split into credits and charges under the Distribution Use of System (DUoS) charges that are levied by the DNO. At LV and HV a credit will be received by an embedded generator for units exported onto the DNOs network. As a general rule the credits at LV are higher than those received at HV as the generator is located ‘deeper’ in the DNO’s network and therefore offsets more costs on behalf of the DNO. It should be noted that the level of credits at LV and HV vary between DNOs.

[73] A more detailed explanation of the components that make up embedded benefits is contained in Appendix 4
[74] P350 is a Balancing and Settlement Code change to introduce locational transmission losses

Where a generator connects at Extra High Voltage (EHV)[75], a credit may be received from the DNO, but this will not always be the case. In addition, a capacity charge and fixed charge may be incurred. The credits will be calculated by the DNO on a site-specific basis and will therefore be based on the individual site and network to which it is connected.

The second embedded benefit at the distribution level that is determined by voltage of connection is the application of distribution losses. These are applied to the export from a generator and have the effect of increasing the export volume that enters the national settlement system that is used to bill market participants. The lower the voltage of connection, the greater the revenue stream that can be expected.

7.3.4 Type of Generation

The type of generation will impact a number of revenue streams. DUoS credits and charges differentiate between intermittent and non-intermittent plant. At LV and HV, intermittent plant receive a single rate credit, whereas non-intermittent plant receives a time of day credit based on the red, amber and green timebands with a higher credit assigned to the red timeband. At EHV it is only non-intermittent generation that is eligible for a DUoS credit. Any credits that are applied to EHV sites are based on the super-red timeband. This timeband is determined by the DNO and represents the time when their network is most congested. There will be no credits available at times outside of the super-red timeband.

The type of generation may also determine whether a plant is eligible to participate in the capacity market or to receive a renewables subsidy. Where a plant is renewable it is likely to be eligible to bid into one of the renewable schemes. However, where a site is in receipt of a renewable subsidy, it will not be eligible to participate in the capacity market.

7.3.5 Contractual Arrangements

The contractual arrangements that are in place to secure a route to market will impact on the revenue received for export from an embedded generator.

Under a standard PPA, the agreement specifies the price for wholesale power in a range of formats. The wholesale price can be a simple unit based value for the year as a whole or a rate that is split into time periods. Alternatively, the wholesale price may be linked to short term market prices or a market related indexation may be used. In addition, a PPA will specify the share of the embedded benefits that the generator can expect and possibly a management fee.

The terms and conditions agreed under a PPA will vary as these contracts are individually negotiated, or where agreed through an auction, will depend on market rates at that time. As a general rule, the more certainty a generator can give on the running regime and the more reliable the export, the greater the share of embedded benefits that can be achieved. This is because generators with a reliable and predictable running regime are less likely to place the supplier out of balance and therefore increase their exposure to cash out prices.

The income that can be achieved through alternative routes to market will depend on the actual contract that is negotiated with the end customer (in the case of a direct route to market or through a corporate PPA) or the proportion of the supplier margin that can be captured by adopting the supplier route to market. The commercial implications of these options are considered later in this Chapter.

7.4 Revenue generated under baseline assessment

To provide a guide on the revenue that can be generated under the different routes to market, a baseline assessment has been undertaken to determine the revenue that can be realised under a standard PPA

[75] Extra High Voltage is defined for charging purposes as any connection at a voltage greater than 11kV or a connection at 11kV where the meter is situated within the curtilage of a primary substation. Any site that is connected to the 11kV network is classified as HV.

agreement for a 1MW embedded generator. The alternative routes to markets are then compared to this baseline to determine the additional revenue that may be captured in each case.

7.4.1 Assumptions underlying the baseline assessment

A number of assumptions have been made to determine the revenue generated under a standard PPA in 2017-18 which are shown below:

Figure 23: Assumptions used to derive baseline assessment

Category	Assumptions
Plant Description	Non-intermittent gas fired CHP
Average Wholesale Price	£40/MWh at Baseload (70% load factor**) £70/MWh at All Year Peak (16% load factor) £90/MWh at Winter Peak (6% load factor)
Embedded Benefits captured under PPA	95%
Load Factor over Triad period	100%
Load Factor over 4-7pm, Nov - Feb	100%
Capacity Market de-rating	90%
Qualifies for EHV Use of System credits?	Eligible
Capacity Market Supplier Levy*	Excluded

* *The capacity market supplier charge is an embedded benefit in 2017-18, but has been excluded from the baseline assessment as BEIS has proposed removing this embedded benefit from April 2018.*

*** See section* Revenue generated under baseline assessment for 2017-18 *7.4.2 to relate load factor to running regime*

7.4.2 Revenue generated under baseline assessment for 2017-18

The baseline assessment has been produced for the April 2017 to March 2018 charging year. Due to the many factors that influence the level of revenue, a matrix approach has been adopted that enables the revenue for an embedded generator to be assessed based on the following variables:

- Location – By DNO area
- Running Regime - Set as either Baseload (assumed 70% load factor), all year peak (typically running 14:00-20:00 on weekdays[76] across the year- 16% load factor) or winter peak (typically running 14:00-20:00 on weekdays, November-February - 6% load factor)

[76] Time of peak will vary between Summer and Winter

- Connection voltage - Set at either low voltage, high voltage or extra high voltage

The table below shows the expected income in £/MWh in 2017-18 to allow for a comparative assessment of income. This table includes income from the wholesale market and embedded benefits but excludes income from the capacity market as this can be earned independently of the variables identified. The table also excludes the capacity market supplier charge embedded benefit which BEIS has indicated will be removed as an embedded benefit.

Figure 24: Potential revenue earned by CHP expressed in £/MWh[77]

DNO Area	Baseload			All Year Peak			Winter Peak		
Voltage of Connection	**LV**	**HV**	**EHV**	**LV**	**HV**	**EHV**	**LV**	**HV**	**EHV**
ENWL	63.8	51.4	52.5	99.2	84.9	79.2	165.5	148.4	140.8
NPG Northeast	59.0	54.1	49.9	90.6	76.3	72.8	148.4	133.2	127.5
NPG Yorkshire	60.0	55.1	51.5	98.5	82.0	78.5	163.6	144.6	140.8
SPEN SPD	59.2	53.2	49.2	87.8	72.1	66.4	137.0	119.9	112.3
SPEN SPM	67.2	59.5	52.5	107.0	88.5	79.9	176.9	154.1	144.6
SSEPD SEPD	61.5	58.1	52.8	103.5	92.0	84.2	178.8	165.5	156.0
SSEPD SHEPD	62.9	54.5	51.2	89.2	74.2	69.9	135.1	119.9	114.2
UKPN EPN	64.1	58.7	54.3	103.5	89.9	82.8	175.0	159.8	150.3
UKPN LPN	64.4	59.8	52.8	107.0	92.0	85.6	182.6	165.5	157.9
UKPN SPN	62.5	59.0	54.5	102.7	92.0	84.2	176.9	165.5	156.0
WPD EastM	60.2	55.6	52.0	94.9	84.2	78.5	161.7	152.2	142.7
WPD SWales	60.8	57.7	52.2	95.6	87.0	79.9	161.7	152.2	142.7
WPD SWest	61.6	57.6	53.3	99.2	91.3	82.8	171.2	163.6	152.2
WPD WestM	62.9	55.6[78]	52.8	109.2	87.8	81.3	178.8	156.0	148.4
Average Value	62.2	56.4	52.3	99.1	85.3	79.0	165.3	150.0	141.9

To use this table, multiply a generator's export capacity by the expected number of hours that it is expected to run. Then select the appropriate value from the table, based on the running regime that most closely matches the expected number of running hours, to achieve an estimate of the revenue. Where a capacity market contract is also achieved, this can also be added to the total. To do this the de-rated[79] capacity is multiplied by the capacity market clearing price to determine the additional income.

[77] This table has been calculated using an embedded generation revenue model created by Cornwall
[78] This value has been expanded in the section below to provide an example of how this table has been derived
[79] De-rated capacity is the capacity after the de-rating value is applied in the capacity market. This factor is applied to reflect the typical availability of types of generating plant. For CHP this value is approximately 90%.

This table illustrates the trade-off between average price achieved and the number of running hours. Consequently, any planned routine maintenance should be scheduled for when wholesale prices and embedded benefits are low. This may require some flexibility in the maintenance schedule and a review of wholesale market prices.

7.4.3 Example Calculation

To assist in the assessment of the commercial business case for an embedded generator under a PPA, an example calculation is shown below for the income that would be generated in 2017-18. For simplicity, this example assumes that the generator receives 100% of the revenue under the PPA.

Figure 25: Example revenue calculation for a 1MW CHP site based in WPD West Midlands area

Generator: Gas-fired CHP

DNO Area: West Midlands (WPD)

Export Capacity: 1MW

Voltage of Connection: High Voltage

Running Regime: 70% load factor

Load factor over Triad and winter peak (4-7pm, Nov-Feb): 100%

Income Stream	2017-18 (£)	Calculation
Wholesale	£245,280	Average wholesale price (£40/MWh) x 1 MW * 70% load factor * 8760 hours
Triad Benefit *	£49,457	Triad Rate (£49.46/kW) * 1,000 kW
Transmission losses **	£2,968	Wholesale income (£245,280) * Average transmission losses (1.21%)
Balancing Services Use of System (BSUoS)	£14,778	Average BSUoS (£2.41/MWh) * 1MW * 70% load factor * 8760 hours
Assistance for Areas with High Distribution Costs (AAHEDC)	£1,349	AAHEDC (£0.22/MWh) * 1MW * 70% load factor * 8760 hours
Residual Cashflow Reallocation Cashflow (RCRC)	£61	Average RCRC (£0.01/MWh) * 1MW * 70% load factor * 8760 hours
Generation Distribution Use of System (GDUoS)	£15,330	Average GDUoS (£2.50/MWh) * 1MW * 70% load factor * 8760 hours
Distribution losses	£11,528	Wholesale income (£245,280) * Average distribution losses (4.7%)
Capacity Market Supplier Charge ***	-	-
Total ****	£340,755	
Capacity Market *****	£6,255	CM clearing price (£6.95/kW) * 1,000kW * De-rating factor (90%)
Total incl. Capacity Market	£347,010	
Average per MWh	£55.6	Total incl Capacity Market / (1MW * 8760*70%)

TABLE FOOTNOTES

* Decision from Ofgem on 22 June 2017 reduces this value substantially. Change will be phased in from April 2018. More information is provided in Chapter 10 on regulatory change.

** Transmission losses will move to a locational basis from April 2018

*** Capacity Market Supplier Charge has been excluded from the table as BEIS intend to remove this embedded benefit from April 2018

**** The total revenue (£341,755) can be divided through by the number of units exported (6,132MWh) to derive the average revenue per unit (£55.6/MWh). This reconciles against the value highlighted in table 20 above

***** The 2017-18 value is for the T-1 auction that took place in January 2017 which cleared at £6.95/kW. The T-4 auctions have cleared at higher levels ranging from £18.0/kW to £22.5/kW.

7.5 Revenue impact of adopting a direct route to market

Where an embedded generator adopts a direct route to market it can either self-supply where sufficient demand exists on the same site or sell direct to customers using a private wire agreement.

7.5.1 Self-Supply

Under a self-supply arrangement, the export from an embedded generator offsets the costs of the on-site demand. Consequently, the savings that accrue are equivalent to the cost of procuring the electricity for the import into the site. The import charge will contain costs that relate to the following items:

- Wholesale prices
- Network charges (include transmission, distribution, system operator costs and losses)
- Supplier obligations (recovery of renewables obligation, feed-in-tariffs, CfDs and capacity market)[80]
- Supplier costs (recovery of costs associated with supply, including metering costs)
- Value Added Tax (VAT)
- Climate Change Levy

A self-supply arrangement will avoid the majority of these elements with the exception of VAT. In addition, it is likely that the generator will remain liable for the Climate Change Levy (CCL). However, a CHP station assessed and fully certified under the CHPQA programme is eligible for favourable treatment under the CCL legislation. For example, a CHP that increases the heat it supplies and as a consequence gains a CHPQA certificate, will become eligible for an exemption from the main rate of CCL of the electricity it supplies via a direct route to market. Full details of the exemptions are available from HM Revenues and Customs.

The retail price for an end customer will vary from site to site. To provide an indication of the additional revenue (which is realised via a reduction in the retail cost for the demand customer) that can be generated under a self-supply arrangement, a range of tariffs for a HV demand customer have been modelled, which include all the cost elements of typical import tariff as outlined above, but exclude the CCL for comparative purposes. In each case the potential saving compared to revenue for a HV generator under the baseline assessment is used:

[80] Some large users may be exempt from paying some of the supplier obligation elements of their import tariff. In these cases, the costs offset by having a private wire arrangement will be lower.

Figure 26: Revenue generated by an embedded generator through offsetting different demand tariffs

	Low Import Price	Medium Import Price	High Import Price
Import Price (p/kWh)	9.5	10.0	10.5
Import price after reduction for VAT and CCL (p/kWh)[81]	7.4	7.9	8.3
Units exported from 1MW CHP at 70% load factor (kWh)	6,132,000	6,132,000	6,132,000
Avoided import tariff cost (£)	£456,425	£481,975	£507,525
Illustrative revenue for 1MW CHP in West Midlands area (from baseline assessment of standard PPA)	£347,010	£347,010	£347,010
Net benefit of self-supply versus PPA export	£109,416	£134,966	£160,516
Percentage uplift in revenue over PPA export	32%	39%	46%

7.5.2 Private wire

Under a private wire agreement, the export from an embedded generator offsets some or all the costs of one or more demand customers who are connected to the CHP using a private wire. The savings that accrue are similar to that achieved under the self-supply route. However, there is the additional cost of installing and maintaining a private wire and some of the savings achieved will flow to the demand customer as an incentive for them to enter the agreement.

The benefit that can be achieved through a private wire approach is largely dependent on the cost of the private wire. If substantial infrastructure is required, this may make the private wire approach uneconomic. To assess the potential impact, three scenarios have been assessed with different infrastructure costs and compared to the baseline assessment. An import tariff of 10p/kWh, which is the central case in the self-supply example has been used for comparative purposes. In all other respects, the values used are the same.

There are a large number of variables that can impact the annualised cost of the private wire. Particular regard should be given to the following factors:

Savings for demand customers

The Gateshead Energy Centre sells their output via a private wire to a number of large customers. The contractual arrangements mean customers are signed up for longer term deals and in return receive a minimum discount of 5% on the prevailing market rate for their heat and power costs compared to buying direct from the market.

For more details on the case studies see Appendix 1

- Depreciation period – depending on the perceived

[81] VAT assumed at 20% (as applicable for business customers) and CCL rate assumed at £0.568/MWh (Rate from 1 April 2017)

risk of the demand customer, and how the private wire is financed, the period over which the asset is depreciated can range anywhere from 5 years upwards.

- Type of wire – Underground wire is more expensive to install, although if this work is undertaken when a site is being developed the incremental cost can be minimised (e.g. the majority of excavation costs can be avoided if electricity cables are laid in the trenches used for heat network pipes).
- Additional assets – switching gear and transformer may need to be installed
- The length and capacity of the private wire and the potential for losses across the wire

The differing capital costs considered and annualised cost in each case are set out in the table below. The differing capital costs in figure 23 represent a range of private wire connection costs and section 4.4.1 provides an indication of the magnitude of costs that may be incurred depending on the size of the infrastructure required:

Figure 27: Annualised cost for private wire scenarios

	Low private wire capex	Medium private wire capex	High private wire capex
Capital expenditure	£100,000	£500,000	£1,000,000
Depreciation Period (Years)	15	15	15
O&M cost (1.5%)	£1,500	£7,500	£15,000
Annualised costs	£8,167	£40,833	£81,667

To provide an illustration of the additional revenue that may be earned from a private wire arrangement, the annualised cost of the private wire is incorporated into an assessment of private wire relative to the baseline assessment. The table below demonstrates the potential for additional revenue that can be earned based on an avoided import price of 10p/kWh, a capital investment in private wire of between £0.1m and £1m and a 5% discount provided to the end customers. There will also be some small network losses incurred over the private wire, but these are ignored for modelling purposes. The actual level of losses will be site specific, but are likely to be much lower than the values published by DNOs which represent the losses from the Grid Supply Point[82] (GSP) down to premises at a voltage level. The private wire losses will relate to a much shorter piece of wire than that used by the DNO and normally only use one or two voltage levels. It should be noted that costs relating to VAT and the Climate Change Levy (CCL) are also likely to be incurred, unless a threshold applies or a reduced level of VAT is applicable.

[82] A GSP is where the distribution network connects to the transmission network

Figure 28: Potential revenue impact of a private wire agreement

	Low private wire capex	Medium private wire capex	High private wire capex
Import Price (p/kWh)	10.0	10.0	10.0
Import price after reduction for VAT and CCL (p/kWh)	7.9	7.9	7.9
Units exported from 1MW CHP at 70% load factor (kWh)	6,132,000	6,132,000	6,132,000
Avoided import tariff cost (£)	£481,975	£481,975	£481,975
Illustrative revenue from standard PPA for 1MW CHP in West Midlands area	£347,010	£347,010	£347,010
Private wire annualized cost	-£8,167	-£40,833	-£81,667
Retail discount for demand customer (5%)	-£24,099	-£24,099	-£24,099
Net benefit of private wire versus PPA export	£102,700	£70,034	£29,200
Percentage uplift in revenue	30%	20%	8%

7.6 Revenue impact of adopting a supplier route to market

Chapter 5 explored the benefits and risks of adopting a supplier route to market. This chapter looks at such a strategy from a commercial perspective. The key fundamental driver in developing a profitable supply business is to gain a portfolio of customers that is sufficiently large (in supplied volume terms), and generates sufficient revenue to cover the fixed and operational costs of the business. The three main types of supply that may be adopted as a route to market are:

- Fully licensed suppliers.
- Licence lite suppliers.
- White label suppliers.

The main difference between the routes to market is the costs and the level of activity retained in-house or outsourced – for example, responsibility for industry code compliance, trading, or billing. For each of the categories of supplier above, there is the potential to outsource a number of activities – see Figure 15: Services undertaken within a supply business. The degree to which services are outsourced or kept in-house will impact on the fixed cost base and the operational cost of the supply business. Where more services are out sourced, this will correspond to a decrease in potential value captured together with a reduction in the business risk associated with delivering the activity. One of the key success factors for operating a successful supply business is optimising the risk reward trade-off between business activities that maximises the overall return while minimising the project risk.

Note: Where a supply option is pursued, the primary objective is to ensure sufficient power is contracted at all times to match expected customer demand. For the Licence Lite and fully licensed supply options it is unlikely that CHP export will match expected customer demand at all times. Therefore, the supplier will need to have in place additional arrangements to access power from the market (or to dispose of power). The proportion of power to meet customer demand from CHP export and other sources (e.g. additional PPAs and wholesale market contracts) will be an important consideration for whether the route is viable and achieves the desired aims.

This section is not intended to provide a full business modelling assessment of setting up a supply business. Instead, illustrative values are provided to enable the quantum of set up and operational costs to be assessed. Further guidance on the costs and revenues that are achievable under a supply route to market is available from the following sources:

- Energy Company Consolidated Segmental Statements: https://www.ofgem.gov.uk/publications-and-updates/energy-companies-consolidated-segmental-statements-css
- NERA report on energy supply margins: http://www.nera.com/content/dam/nera/publications/2015/PUB_EnergySupplyMargins_0115.pdf

7.6.1 Set-up costs

The set-up costs associated with a supply business are lowest for a White Label supply, higher for a licence-lite arrangement and highest for a fully licensed supplier. Within each category there are variations depending on which services are outsourced and the target market. A supply business that targets domestic customers can expect higher set up costs than one that plans to participate in the commercial and industrial sector.

Set-up costs are a function of the necessary IT required, staffing resource, company overheads (e.g. office space, typical business expenditure, telephony, insurance etc.) and the time taken to complete adequate business and financial planning and to establish the legal entity undertaking the activity.

The table below provides an *illustrative* range of costs that are likely to be incurred in setting up each category of supply business:

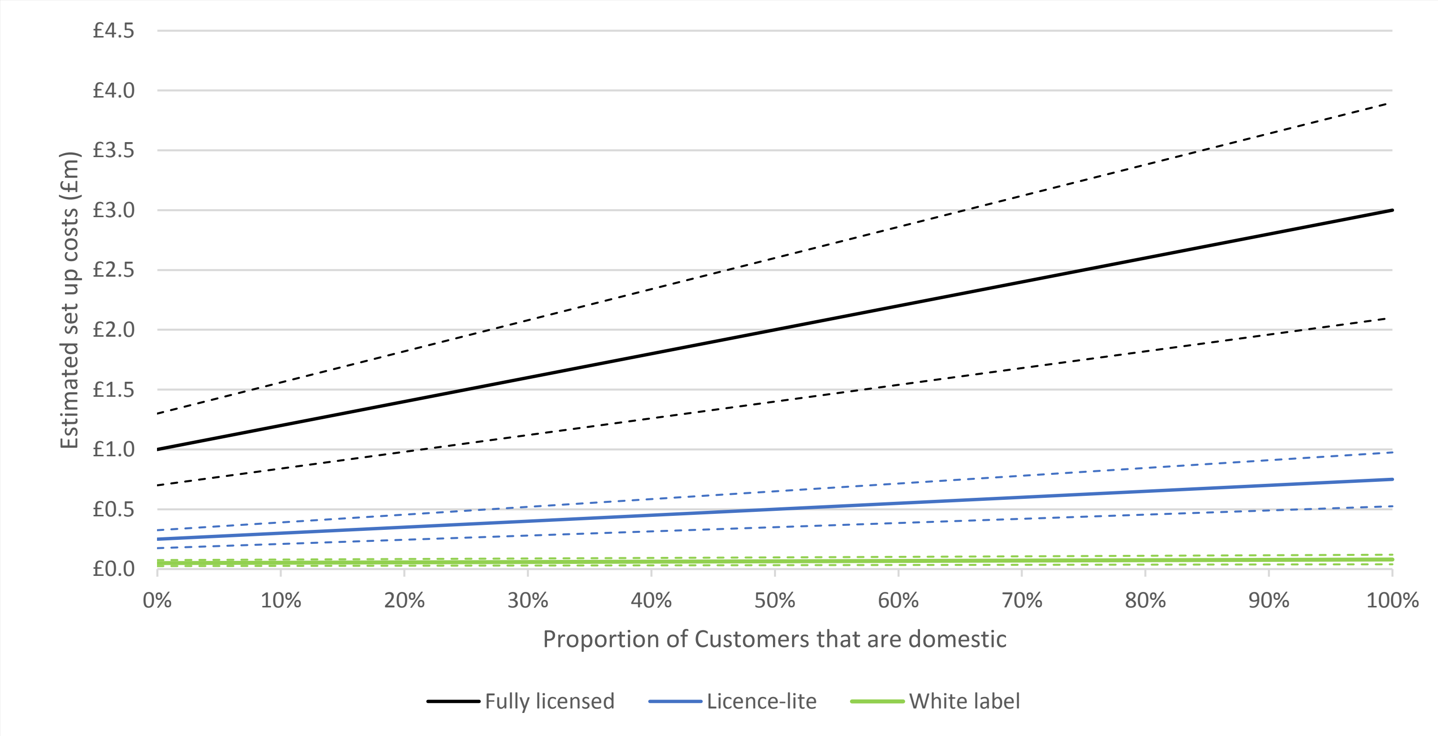
Figure 29: Illustrative range of supplier set up costs

	Indicative supplier set-up costs		
Cost item	**Fully licensed supply**	**Licence lite**	**White label**
Business and financial planning	£100k - £250k	£25k - £75k	£0 - £10k
Prequalified licence + IT system + managed services	£150k - £450k	N/A	N/A
Customer Relationship Management (CRM) system	£50k – £300k	£50k - £300k	£0k - £10k
Legal and market advisory support	£100k - £300k	£25k - £75k	£0k - £10k
Business overheads	£100k - £500k	£50k - £100k	£0k - £10k
Working capital (trading, collateral etc.)	£300k - £800k	£25k - £75k	£0k -£10k
Staff	£200k - £400k	£75k - £125k	£20k - £30k
Total	£1mn - £3mn	£250k - £750k	£50k - £80k

Note: Figures are purely illustrative and are provided to give an indication of the likely order of magnitude of costs related to different elements of establishing a supply presence. Actual costs will be determined by wider market factors (e.g. for IT requirements), the target market (e.g. generally set-up costs would be lower for a supplier selling only to businesses, but much higher for a dual fuel supplier looking to sell to households), the planning and set-up approach (e.g. outsourcing and bringing expertise in-house), the time taken to launch the supply entity, potential to share services (e.g. office space), and the cost of accessing working capital (where relevant).

The table above provides a wide range of costs to set up each type of supply business as this is representative of the set-up options which allows many of the business elements to be outsourced or developed in house. The mix of customers is also an important consideration and the graph below provides an indication of how the set-up costs are likely to vary with the relative proportion of domestic to non-domestic customers that the new supplier plans to target for supply business model.

Figure 30: Indicative set-up costs (£m) against proportion of domestic/ non-domestic customers



7.6.2 Operational costs

The operational costs incurred for each category of supply business are very different. White label will typically require limited resource for sales and marketing and contract management with its partner fully licensed supplier. The licensed routes (Licence Lite and fully licensed) incur significantly higher operational costs associated with staffing, IT licensing, trading, and importantly credit and collateral calls.

The licensed routes will also incur significant working capital requirements to cover operational costs up until the point that the company breaks even. On an enduring basis, the licensed routes will need access to significant working capital to cover wholesale counterparty and other credit requirements. A fully licensed supplier must post credit with network companies and the central market administrator to cover expected imbalance positions.

A review of the consolidated segmental statements of the big six energy suppliers suggests that the cost to serve a domestic customer is in the region of £21/MWh and £6/MWh to serve a non-domestic customer.

The cost to serve values are used in the table below to provide an illustrative portfolio size that is required for each category of supply business to become profitable. For each supplier model, three scenarios are considered; a low cost to serve business model (mainly commercial and industrial customers - £6/MWh), a mixed business model (assumed 50% domestic and 50% industrial and commercial - £13.5/MWh) and a high cost to serve business model (assumed mainly domestic customers - £21/MWh). In each case, the breakeven volume decreases as the cost to serve increases as smaller customers tend to be more profitable for a supplier than large commercial and industrial sites:

Figure 31: Illustrative breakeven volume for supply business models

	Cost to serve (£/MWh)	Annualised Start-up costs recovered over 10 years (£ pa)	Typical operational cost (£ pa) [mid-range]	Breakeven volume (GWh)
White Label	6	£6,500	£75,000	13.6
	13.5	£6,500	£75,000	6.0
	21	£6,500	£75,000	3.9
Licence Lite	6	£50,000	£350,000	66.7
	13.5	£50,000	£350,000	29.6
	21	£50,000	£350,000	19.0
Fully Licensed	6	£200,000	£1,250,000	241.7
	13.5	£200,000	£1,250,000	107.4
	21	£200,000	£1,250,000	69.0

This analysis is based on an assumption of the typical operational costs of operating each type of supply business. It should be noted that these costs will increase as a supplier services more customers, although the per unit cost will decrease. More detail on the annual cost assumptions are provided in Appendix 2 which provides information on each of the supplier business models. However, a supply business venture would require a fully costed bespoke business model to be constructed and professional advice will need to be procured to assist in estimating budgets and breakeven levels.

7.6.3 Supply business model and CHP export

The decision to select a supplier route to market can be considered a standalone decision in many respects as the supply business will need to be profitable in its own right. However, where an embedded generator or group of generators decide that becoming a supplier is an appropriate route to market, the share of benefits that the supplier typically retains under a standard PPA can now become captured by the generator.

To assess the impact of this is difficult due to the difference between PPAs, particularly in how the wholesale price is captured. However, under a standard PPA, the electricity supplier typically retains a proportion of the wholesale market revenue and embedded benefits. Adopting a supplier route to market means the generator is more likely to capture a greater proportion of the benefits. However, becoming a supplier also means that any imbalance costs associated with the generator will accrue to the supplier and this risk needs to be considered.

To assess the impact of a generator adopting a supplier route to market, the revenue that is normally retained under a PPA needs to be assessed. Figure 14 in section 4.5.2 provides indicative ranges for value retention for different revenue components under the PPA. The value retained by the supplier will depend on market conditions and the characteristics of the generator including the reliability of the generator and the duration of the PPA. Based on the values contained within figure 14, a generator can expect their supplier to retain anywhere between 5% and 15% of the value of the generator's revenue, particularly for a long term PPA which would mostly closely align to the requirements of a CHP that is considering entering the supply market. As CHP is a non-intermittent form of generation that is reasonably predictable, the lower end of this range is more likely. Providing an indicative range of 5% to 10%.

For a Licence Lite or fully licensed supplier, the generation export is allocated to the supplier and therefore it would be reasonable to assume 100% of the revenue can be captured, providing an uplift of between 5% and 10%. For a White Label supply, the export would be registered to the senior supplier. Consequently, some uplift may be achieved as part of the agreement between the senior supplier and White Label supplier. However, this is likely to be less than under a Licence Lite or fully licensed supplier approach and a reasonable assumption for an illustrative range is an uplift of 2% and 4%. A summary of the expected benefits compared to a standard PPA is below:

- Fully licensed supplier - Expected increase in generation revenue: 5% to 10%
- Licence-lite supplier - Expected increase in generation revenue: 5% to 10%
- White label supplier - Expected increase in generation revenue: 2% to 4%

7.7 Revenue impact of adopting a corporate PPA route to market

The corporate PPA route to market has potential to benefit a generator over a standard PPA in the following areas:

- Reduced supplier margin – As the supplier is simply the facilitator to implement the agreement between the generator and end customer(s), the supplier saves customer acquisition costs which may be shared between the generator and end customer.
- Long term security – Corporate PPAs tend to be longer term than standard PPAs and offer greater certainty to both the generator and end customer. Whether this enhances the earnings for the generator export will depend on underlying market price movements but risk is reduced. This long-term security is moot if the generator and end customer are financially linked (e.g. if an LA is supplying itself).

It should be noted that a synthetic PPA will only benefit from a greater increase in long term security and will not be able to capture a share of the supplier margin. This is because a synthetic PPA exists between the generator and end customer and does not involve the supplier. Synthetic PPAs are irrelevant if the generator and end customer are the same legal entity.

To estimate the additional income that may be earned under a corporate PPA (limited to sleeving and peer-to peer agreements), the baseline assessment has been used with a share of supplier margin captured. Corporate PPAs are typically undertaken between a generator and large customer(s) and consequently, the supplier margin on the end customer tends to be low. The level of profit margin applied by suppliers when quoting customers is commercially confidential and therefore not a published value, but a rough estimate is a range of 0.5% to 3% of the total bill. The amount of this margin that can be captured under a corporate PPA is likely to be a small proportion of this and to provide an illustration of the additional benefit that may be captured, three scenarios have been modelled representing the generator capturing an additional margin of between 0.2% and 0.6%:

Figure 32: Illustrative revenue generated by an embedded generator under a sleeving or peer-to-peer agreement

	Low supply margin	Medium supply margin	High supply margin
Supply margin captured	0.20%	0.40%	0.60%
Retail tariff (p/kWh)	10	10	10
Units exported from 1MW CHP at 70% load factor (kWh)	6,132,000	6,132,000	6,132,000
Supply margin captured (£)*	£1,226	£2,453	£3,679
Illustrative revenue for 1MW CHP in West Midlands area	£347,010	£347,010	£347,010
Percentage uplift in revenue	0.4%	0.7%	1.1%

* Note: Although these types of corporate PPAs are potentially beneficial due to the reduced electricity supply margin, consideration should be given to any additional costs that may be incurred to negotiate and agree the contract. This may include costs of procuring external advice which may exceed the savings achieved through the reduced suppy margin. The long term security offered by these contract arrangements could be of value and should also be considered by the generator and retail customer.

7.8 Third party access

Since 2011 customers connected to a private wire network have the right to choose their own supplier. This followed a ruling in 2008 by the European Court of Justice on the Citiworks case, deciding that all distribution networks, regardless of size, must allow customers to take supply from any supplier, and that Member States' exempting of private networks from this requirement was a violation of the European Electricity Directive. This led the UK to develop the Electricity and Gas (Internal Markets) Regulations 2011, which came into effect on 11/11/11..

The impact of this legislation for an embedded generator that connects to customers via a private wire and supplies them with electricity under a supply class exemption, may find that customers opt to move to an independent supplier at a later date. This could lead to the CHP needing to find another route for its export, either to other customers on the private wire or by exporting onto the public network (normally through a PPA).

A further implication for the CHP is that where a customer decides to move to an independent supplier, the owner of the private wire needs to put in place a charging methodology for use of the unlicensed network which is normally levied directly on the customer. Depending on the metering arrangements, it is possible that a meter dispensation may be required to allow "difference" metering to occur which reduces the boundary meter read by the volume consumed by the embedded customer. This ensures the volumes consumed at the boundary and the embedded customer are not double counted. More information on metering dispensations is available from the Elexon website under Balancing and Settlement Code Procedure (BSCP) 514[83].

Although the legislation around third party access has been around for several years, there has not been much take up due to the perceived complexity of the market arrangements, particularly in the area of distribution charges where DNOs have adopted different approaches, and the likelihood that alternative supply arrangement would be more costly (due to the additional on costs associated with taking power from the public network). For a customer that is connected to an unlicensed network to move to an independent supplier, they must be able to find a supplier who is willing to accept them as a customer. At present, due to

[83] BSCP 514 - https://www.elexon.co.uk/wp-content/uploads/2017/02/BSCP514_v33.0.pdf

the complexity, there are not many suppliers who are willing to undertake this risk, and there have been very few instances of customers on unlicensed networks taking advantage of the new legislation.

It should be noted that customers are only likely to move if they can achieve a better price for their electricity than they currently pay under the arrangements from the CHP. Consequently, the pricing strategy for the CHP should take account of market rates when agreeing tariffs with the private wire customers each year.

7.9 Managed Connections

Historically, when generators connected to a distribution network they would be able to export up to their agreed export capacity without restriction. However, as the distribution networks have connected more embedded generation, new generation that requires unrestricted access will often result in additional reinforcement costs and therefore a high connection charge. As a result, DNOs have moved to “managed connections” where a cheaper connection is made available, but with some constraints placed on the connection.

Although the term managed connection is used in these guidance notes, they are also frequently referred to as “constrained”, “flexible” or “alternative” connections. It should be noted that although most connections for embedded generators are of this type, it does not prevent a generator for applying for an unrestricted connection and paying the additional costs.

Flexible Plug & Play

UK Power Networks have completed a three-year trial project to connect distributed generation, such as wind or solar power, to constrained areas of their electricity distribution network.

Under the project, generation was connected under a pro-rata principle of access up to a pre-agreed cap. Once this cap was met a last in first out (LIFO) approach was adopted for further connections. The result was more generation was connected at less cost and some previously unviable schemes became viable.

The benefit of a managed connection is twofold. Firstly, the need for reinforcement of the distribution network is reduced and the connection cost is often substantially lower. Secondly, the lead time to connect the generator is much quicker as it is not reliant on the reinforcement works being undertaken.

Under the managed connection, there will be a range of potential constraints placed upon the connection. These will be site specific and depend on the characteristics of the network that is connected to. As a general rule, generators will be automatically constrained off the system when a fault occurs on the network they are connected to.

7.9.1 Active Network Management Schemes

Active Network Management (ANM) is a more dynamic solution than managed connections to the problem of optimising spare capacity between network users. The Good Practice Guide for ANM[84] defines ANM as:

“*Using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits, thereby reducing the need for reinforcement, speeding up connections and reducing costs.*”

ANM is generally associated with the drive to connect increasingly large numbers of generation, but the ANM principles apply equally to managing the connection of demand customers. The principle of ANM is to manage a series of network assets to ensure the capacity is not breached and thereby enable more connections to occur at a lower cost and to a faster timescale.

Under an ANM system, the export or import from a user is curtailed using either a last in/ first out (LIFO) approach or through a pro-rata approach. The LIFO approach means that the export from the most recent connected generator is curtailed first when the network capacity becomes constrained. Once the most recently connected generator becomes fully curtailed, the ANM system switches to the second most recently

[84] Good Practice Guide for ANM

connected generator to curtail their output and so on, until the constraint is resolved. The LIFO approach means that the most recently connected generator will incur the highest curtailment costs which is justified as they are likely to be the driver of the network constraint.

The pro-rata curtailment approach reduces the export for all generators by the same proportional amount. This means that the impact of the curtailment is shared equally between all participants and the costs are not disproportionally allocated to one party. As it is not possible for the DNO to unilaterally change an existing generators connection agreement and enforce curtailment under the ANM scheme, a pro-rata approach is more likely to be adopted where a number of generators are looking to connect to the same piece of network and therefore it is in their mutual interest to agree a pro-rata approach.

7.10 Chapter summary

The commercial aspects of a route to market are an important consideration and if the commercials of the project do not stack up it is likely to undermine the whole business case. This chapter has looked at the various routes to market and the potential income that can be generated. The table below summarises the commercial differences between the routes to market:

Figure 33: Comparison of routes to market relative to standard PPA

<table>
<tr><th>Route to Market</th><th>Potential Uplift compared to standard PPA baseline</th><th>Long term security</th><th>Comments</th></tr>
<tr><td>Self-Supply</td><td>32% - 46%</td><td>Yes</td><td>Large uplift on baseline PPA achievable</td></tr>
<tr><td>Private Wire</td><td>8% - 30%</td><td>Yes</td><td>Uplift on baseline PPA achievable, but additional costs of private wire and providing discount to end customer need to be considered. Business case assumes electricity demand will exist for the life of the power station.</td></tr>
<tr><td>Full Licence</td><td>5% - 10% plus supply margin</td><td rowspan="3">Some protection against wholesale market movements</td><td rowspan="3">Potential to improve the terms of the PPA by linking to own supplier. Supply business must be of sufficient scale to be profitable to make route to market viable. Offers some protection against wholesale market volatility.</td></tr>
<tr><td>Licence Lite</td><td>5% - 10% plus supply margin</td></tr>
<tr><td>White Label</td><td>2% – 4% plus supply margin</td></tr>
<tr><td>Sleeving/ Peer to Peer</td><td>0.4% - 1.1%</td><td>Yes</td><td>Captures a small proportion of the supply margin. Offers long term security which may be financially beneficial or detrimental depending on market movements.</td></tr>
<tr><td>Synthetic PPA</td><td>0%</td><td>Yes</td><td>No uplift compared to a standard PPA, but offers long term security which may be financially beneficial or detrimental depending on market movements.</td></tr>
</table>

8 Practicalities of implementation

What is covered in this chapter?

This chapter examines the practical considerations that need to be taken into account when adopting each of the routes to markets identified in these guidance notes. The following topics are covered in this chapter:

- The commercial practicalities of implementing each route to market.
- High level process diagrams for each route to market, including illustrative timelines
- The strategy of heat lead design and the relevance of electrical storage

8.1 Background

The selection of a route to market for the electrical export from an embedded generator project has been reviewed in previous chapters from a commercial, regulatory and strategic perspective, including taking account of stakeholder objectives. However, once a route to market is selected, there are a range of practical issues that need to be considered to implement the chosen route. This chapter provides information on how a CHP project should go about implementing a route to market and highlights issues that stakeholders should be aware of.

It should be noted that this process is iterative and the implementation issues should be considered in the context of the actual choice of a route to market. In some cases, the implementation issues may lead a party to consider a different route to market.

8.2 Commercial practicalities

The commercial reality of adopting a route to market will require a number of tasks to be undertaken. These guidance notes do not extend to fully cover the end to end process required to adopt the route to market in each case. However, a high-level guide is provided as a checklist to aid the process for stakeholders. It should be noted that HNDU is reportedly developing a stakeholder guidance document which is expected to be published in due course.

8.2.1 Self-supply and private wire

The process of establishing a self-supply of private wire arrangement is similar in some respects to that of a corporate PPA. It hinges on the ability to find a number of customers who are willing to commit to a long-term offtake for the electricity from the generator. However, the difference is that with self-supply and private wire, the demand customer must be located close to the generator to enable them to be directly connected without the need for a substantial investment in network infrastructure.

PROCESS

Where a self-supply approach is adopted, the generator output is consumed by a demand site that is owned by the same entity. Although this means that the agreement and business case is relatively straightforward, there may be the need for some arm length agreements between the generator and demand site. This will depend on whether the generator is set up as a separate corporate entity for commercial or regulatory reasons.

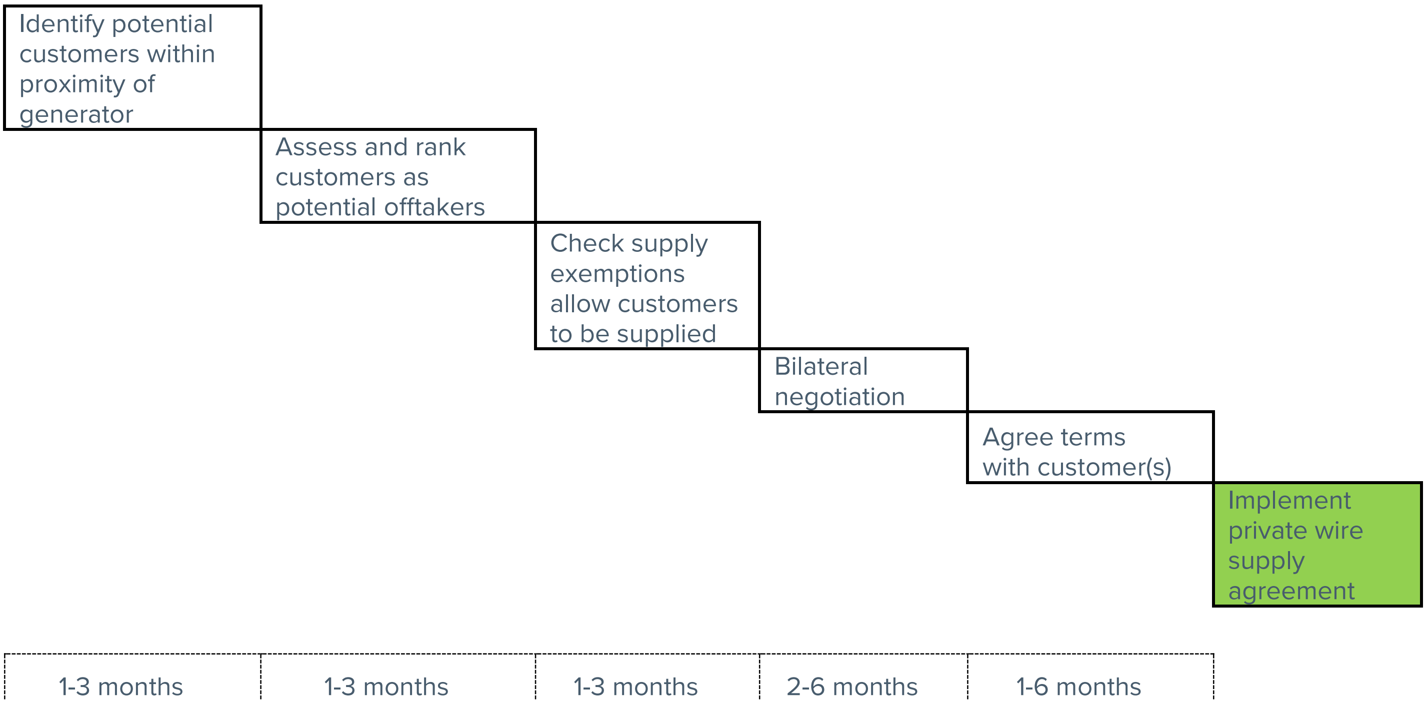
The process of establishing a private wire route to market is to identify a number of potential customers who are within a close enough proximity to make such a route to market worthwhile. The range will depend on the size of the customer(s) and how easily it would be to install a private wire. As a general guide, a 400m radius would be a good starting point to identify applicable customers.

Once customers have been identified, a negotiation can commence. This may require customer education of the workings and benefits as many are unfamiliar with this type of arrangement. In addition, where there are a number of customers, the generator needs to assess each one to determine how well the demand profile matches the expected generation and whether the demand is expected to persist in the long term and the resultant risk if the site closed down or changed their consumption profile. The generator will also need to satisfy themselves that they are able to supply the customer(s) under one of the exemptions from holding a supply licence.

Consideration to how supply is maintained for customers in instances where the generation asset cannot meet demand, for example where the plant is down for maintenance, is also key. Where the approach is self-supply it can be generally assumed that the customer has pre-existing supply arrangements (although these may need to be reviewed). For a private wire arrangement, this can be complicated by the site set-up as the party providing the back-up supply could be the customer or a service offered by the entity providing the private wire supply.

The diagram below shows the processes undertaken when agreeing a private wire agreement for the export from an embedded generator. It should be noted that the timescales provide an indicative range, but the actual time will vary for each site.

Figure 34: Process and timescales for private wire



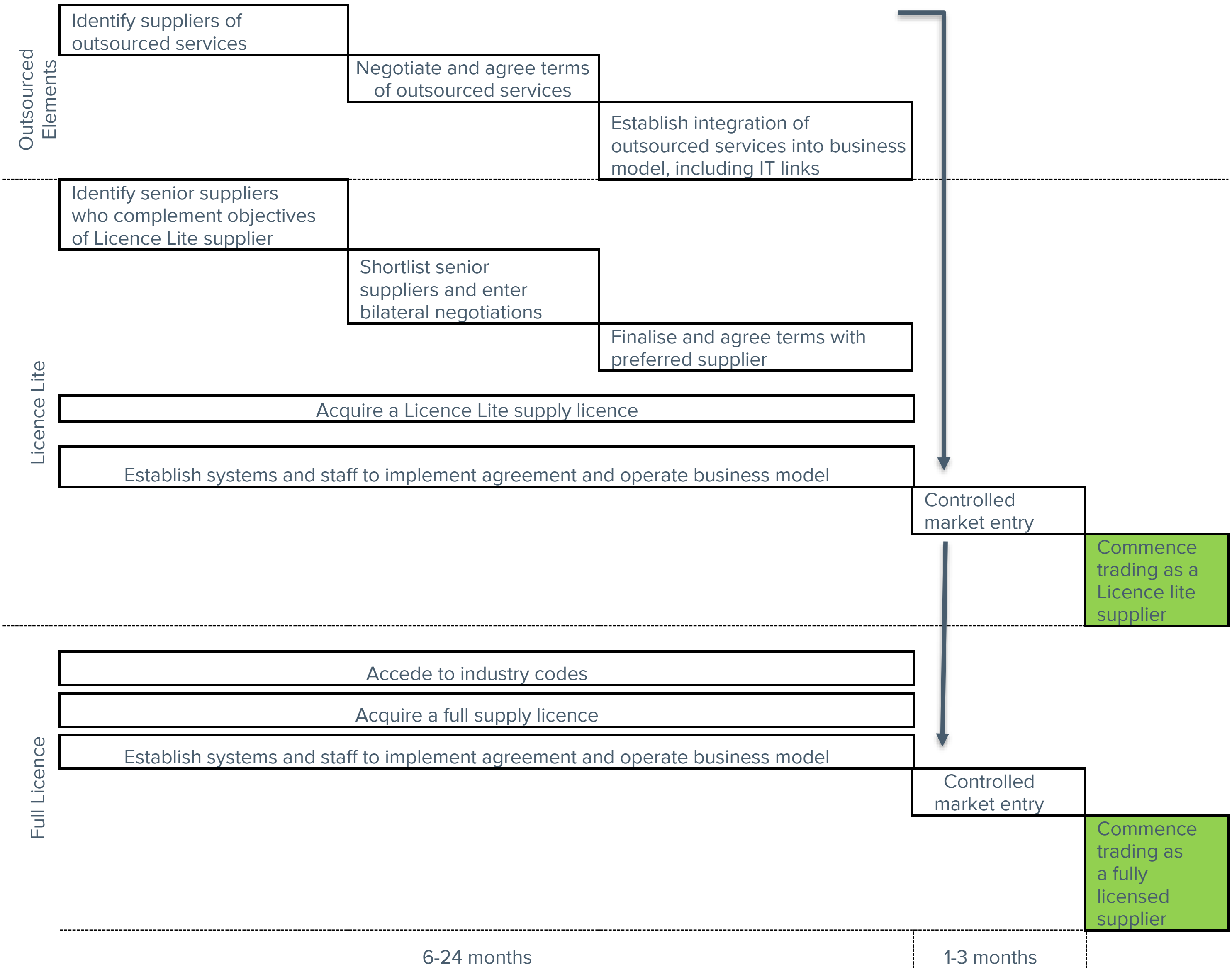
8.2.2 Supplier models

LICENCE LITE AND FULLY LICENSED SUPPLIER

The process to become a Licence Lite or fully licensed supplier is potentially complex and time-consuming. However, the ability to outsource different parts of the business model can shorten the timescales considerably. In addition, the possibility of buying a "supplier in a box"[85] when becoming a fully licensed supplier rather than internally developing all the necessary IT systems and links into the central systems can further shorten the timescales.

Appendix 2 provides high level information on how these arrangements work in practice and the processes involved with setting them up. An illustrative indication of timescales is shown in the diagram below. The timeline has a wide range as this will depend on the degree to which services are outsourced or developed internally.

Figure 35: Process and timescales for Licence Lite and fully licensed supplier



[85] "Supplier in a box" is the term used to describe the procurement of a prequalified electricity supply licensed company from a specialist utility IT systems vendor that has gained an electricity supply licence and acceded to a number of the core industry codes.

WHITE LABEL SUPPLIER

The supplier routes to market vary in complexity and cost. Where a White Label approach is adopted, the route to market is quicker and at lower cost. The generator will need to find a licensed supplier that is willing to act as the senior supplier and is willing to provide all the supply services. The first step in this case is for the generator to determine their approach to market and where a competitive advantage may exist. It is important to set out this strategy in a clear and transparent manner as it will help in finding and negotiating a successful deal with a licensed supplier.

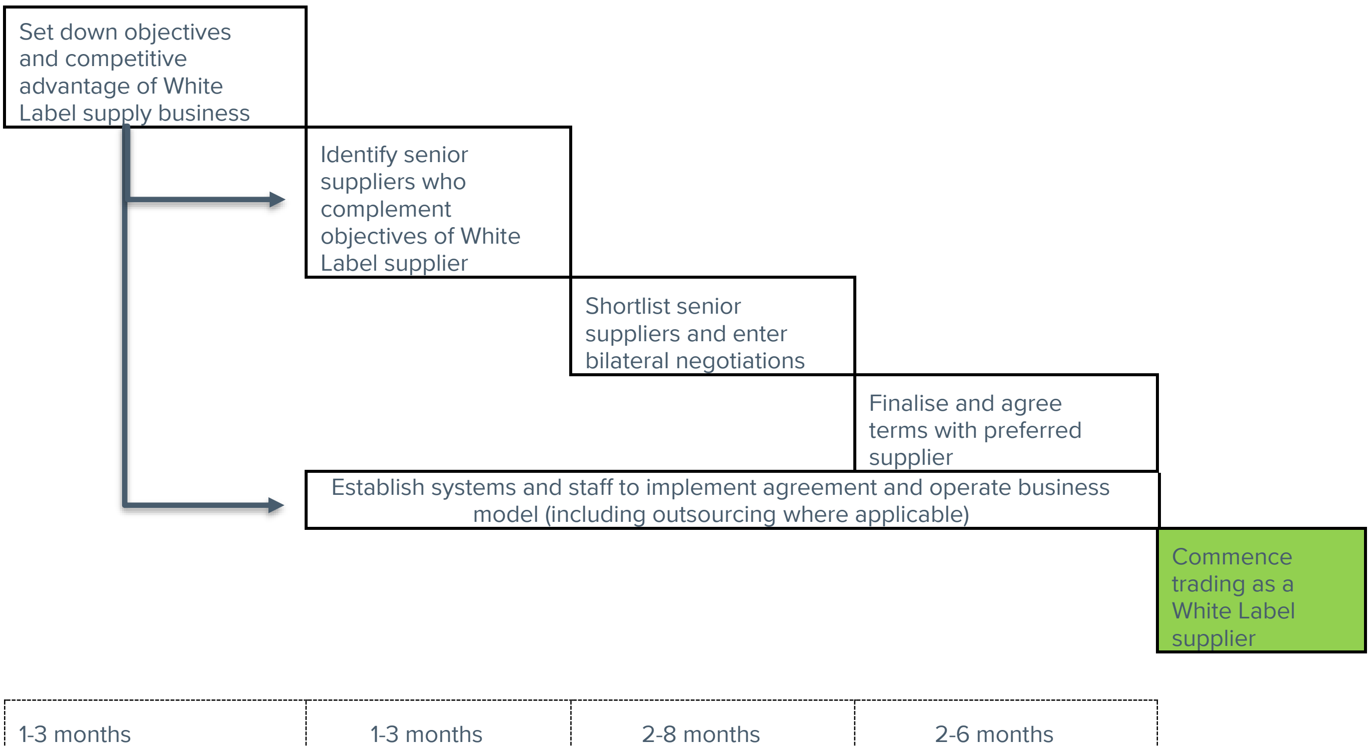
A White Label approach may form a low risk route to enter into the supply market. It enables the new entrant to establish a relationship with end customers and build up a brand without investing in the higher fixed costs associated with Licence Lite or fully licensed supplier options.

Once the strategy has been determined, the White Label supplier needs to decide which, if any, services are to be provided in house and which should be outsourced. This decision may depend on a number of factors, not least of which will be the price at which the service can be provided by a third party. This could form part of the negotiation with the licensed supplier who is likely to be able to provide some or all of the services required.

The next step is to identify which suppliers would be willing to enter into a White Label agreement and to negotiate a contract. The negotiation will depend on a range of factors, but the White Label supplier should focus on their objectives and what they can bring to the table to help the supplier. The greater the perceived benefit of the White Label supplier to the licensed supplier, the more advantageous the resultant deal is likely to be.

The diagram below shows the high-level process and indicative timescales involved with becoming a White Label supplier. The estimated time has a large range for some items representing the uncertainty in these areas, particularly where decisions must be approved at Board level for the process to progress. One way of speeding up the timescales is to work with a senior supplier who is familiar with this type of agreement and is likely to have a standard agreement that can form the basis of the negotiation.

Figure 36: Process and timescales for White Label supplier



8.2.3 Corporate PPAs

Corporate PPAs require a generator to agree to sell their output to a customer (which may include consumption under the control of the generator at a different location) either through a supplier (under a sleeving or peer to peer agreement) or to hedge the price via a synthetic PPA (only relevant if the customer is separate from the generator). In each case, the generator needs to first determine their objectives in seeking this type of agreement and to determine the criteria they will use to approach customers/make the internal business case. If the primary purpose is to achieve a long-term agreement to minimise risk, then end customers with a similar approach to risk can be identified and approached. Where a generator wants to sell to local demand customers or to a demand customer that is associated with the generator (such as a local authority) this may also pre-define the potential counterparties.

Once the objectives for seeking a corporate PPA are established, the next step is to assess potential demand customers to see if they are candidates to enter into the agreement. This will vary between organisations and in most cases it will be necessary to approach the demand customer to establish if there is an appetite. The generator should have regard to the electricity consumption of the end customer relative to the generator. Corporate PPAs are normally agreed between large customers and generators to reduce the time and cost of negotiating the agreement. Where the end customers are small and numerous, this will add time and complexity to the process.

One way of establishing a corporate PPA is via a peer to peer platform. This approach is relatively new and enables generation and end customers to be matched and then linked together via a licensed supplier. This allows customers to support local technologies or renewable generation depending on their purpose for participating in the process. Open Utility released Piclo, which is a new peer to peer platform in 2016. More information is available on their website: www.openutility.com/.

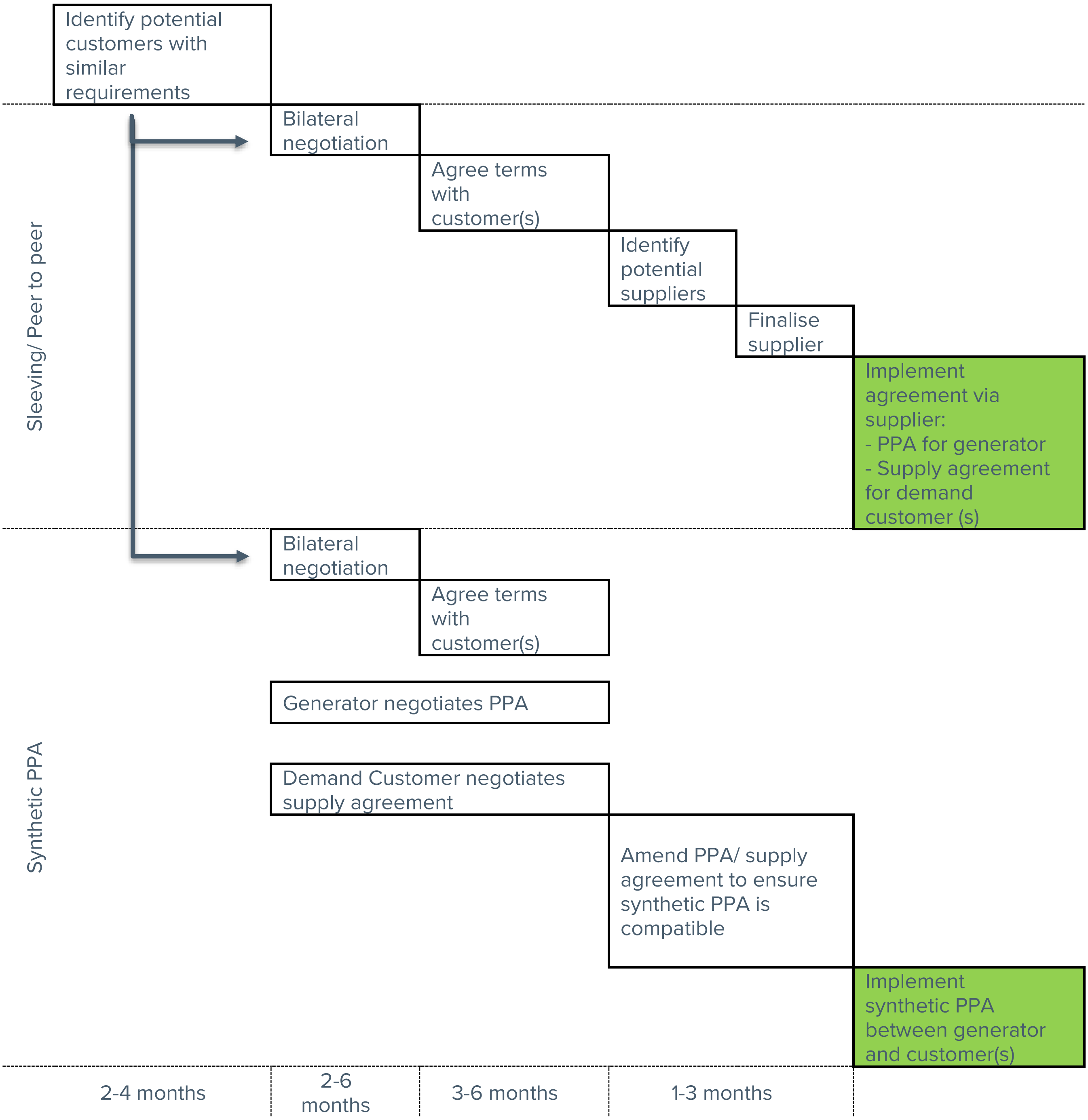
Once a willing demand customer has been identified, an agreement needs to be negotiated between the two counterparties. This will include the price, which normally refers to the wholesale price, but could in theory stretch to other elements. The terms and conditions will be bespoke, however, during negotiation, both parties should be aware that in the case of a sleeving agreement, the agreed deal will need to be implemented via a licensed supplier. Making the agreement excessively complex may make it difficult to implement and therefore difficult to find a supplier who will adopt the agreement. The peer-to-peer approach overcomes this to a degree, as the technology platform will have an inbuilt agreement which allows for a standardised approach that can be automatically adopted by the supplier. The synthetic PPA does not have this constraint as the agreement is between the generator and end customer and does not directly involve a licensed supplier.

The final part of the process is to find a supplier that will implement the agreement. The supplier will require a fee to undertake the process and manage any residual risks, such as imbalance. The generator should approach a number of suppliers to ensure the deal can be implemented at lowest cost.

PROCESS

The diagram below shows the processes undertaken when agreeing a corporate PPA for the export from an embedded generator. It should be noted that the timescales provide an indicative range, but the actual time will vary for each site. A potentially large constraint is the timeline for the large customer to get authorisation to enter into a long-term agreement, particularly if it is the first time they have undertaken this type of deal

Figure 37: Process and timescales for corporate PPA



8.2.4 Standard PPA Route

A standard PPA route can be an attractive proposition because it is a quick and well established route to market. Some new entrants adopt a standard PPA as a holding position while the asset is constructed and once the asset is up and running more complex and potentially higher revenue routes to market are explored. While this route has its merits, and allows management time to be focussed on bringing the asset to market in a timely manner, selecting a different route to market from an early stage in the development of the project can improve the economics of the project and potentially lower the financing costs. Consequently, the standard PPA should be considered alongside the other options at an early stage of the project rather than considered as a worse case default position.

A standard PPA can either be negotiated directly between a supplier and generator or using the E-Power auction. These options are described in more detail below.

NEGOTIATION ROUTE

A generator needs to contact suppliers to determine which are interested in entering into a PPA. All suppliers could potentially fulfil this role and it is not a requirement for the supplier to have sufficient demand to offset the generation. This is because where the export from the generator exceeds the suppliers import, the balance is treated as negative demand. Consequently, embedded benefits will still be credited to the supplier. It should be noted that the only exception to this rule is the embedded benefit that relates to the Capacity Market Supplier Charge (CMSC) which will only be beneficial to a supplier if it has demand which can be offset by the generation. However, this embedded benefit is unlikely to exist past April 2018 due to proposed changes to how it is recovered (see Chapter 10).

Once a number of willing suppliers have been identified an individual negotiation can take place. Most suppliers will be able to provide a standard PPA agreement which will form the basis for the negotiation.

One of the key elements in the PPA will be how the wholesale price element is captured. It is important that the generator understands how they intend to operate the plant to enable the PPA to be structured in the correct way. For instance, if the CHP has some flexibility, a single price applied to all half hours will not enable the generation to maximise the value of this flexibility. Instead a time of use tariff[86] would result in a better income for the CHP. A list of potential options for consideration is contained below. It should be noted that this is not an exhaustive list, and generators may choose bespoke requirements that meet their needs:

- Single unit based price throughout the year
- Time of day tariff that varies across the day or by day type (e.g. weekends/ weekdays)
- Seasonal time of day tariff that varies by time of day and season
- Variable prices that are linked to traded wholesale market prices by season/ month/ day/ etc.
- Optimisation by supplier based on day-ahead or within day half hourly prices
- Supplier to trade the output in the wholesale market based on instructions from the generator

All of these options will require a different degree of interaction for the CHP with the wholesale market and the supplier. The CHP needs to assess each option to determine the best fit for their business model.

Other considerations that will need to form part of the PPA include:

- Availability – The higher the availability of the generator, the less risk for the supplier that they may be placed into an imbalance position or have to enter the wholesale market at short notice to cover the missing volumes through an unforced outage of the CHP site. The PPA will specify a minimum level of availability with associated penalties if it is not met. Amending this level will potentially have an impact on the prices under the PPA. The generator must have regard to the level of reliability they expect from the plant, particularly given the running regime it is expected to operate.
- Embedded benefits – The PPA normally specifies the share as a percentage of embedded benefits that is provided to the CHP.

PPA Terms & Conditions

When sourcing a PPA, the operator for Pimlico noted that the larger energy companies tended to have less stringent PPA terms and conditions, presumably because unforeseen breakdown and shortfall in generation is less significant when it occurs alongside a large fleet of contracted generators.

For more details on the case studies see Appendix 1

[86] A time of use tariff is one where different prices apply at different times of the day and to different days (e.g. weekend/ weekdays). The price may also vary seasonally.

This can be anywhere in the region of 80% to 100%. A CHP needs to compare which supplier is offering the greatest share of benefits, but to compare the PPA as a package, including all the elements. It may be the share for some elements of embedded benefits is high, but the materiality is low.

- The PPA may have management fees associated with it, and this needs to be assessed in the context of the whole package.

E-POWER AUCTIONS

E-Power run regular online auctions to procure a standard PPA for suppliers from embedded generators. E-Power is a subsidiary of the Non-Fossil Purchasing Agency Limited (NFPA).

The procurement is undertaken on a monthly basis with ten to fifteen licensed suppliers typically participating. The PPA covers all the wholesale price element and all embedded benefits except the Triad, which is passed through at 80%. The suppliers bid to secure volume based on a single unit price and there is a range of contract durations available.

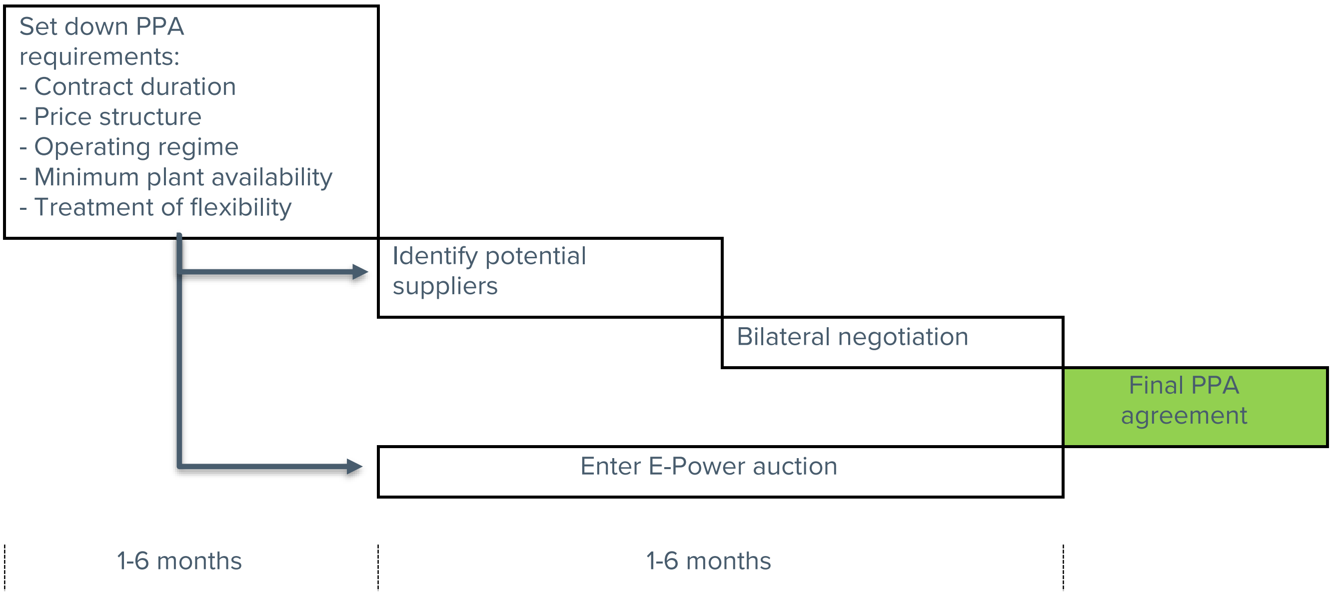
Although any embedded generator is able to participate, the use of a single price for the export from an embedded generator, means this route to market is more likely to be adopted by less flexible generation such as renewables. Some CHP are currently participating in the auctions.

More information is available on the E-Power website: www.epowerauctions.co.uk

PROCESS

Figure 37 shows the processes undertaken when agreeing a standard PPA for the export from an embedded generator. It should be noted that the timescales provide an indicative range, but the actual time will vary for each site and how advanced a project is. For example, where an embedded generator has been established for a number of years and has a track record for agreeing PPAs, the identification of suppliers and the negotiation of the PPA terms is likely to be much shorter than a new build that is looking to enter into its first PPA.

Figure 38: Process and timescales for standard PPA



8.3 Corporate Structure and financing

In section 6.3 we discuss powers available to local authorities to sell electricity.

If the Local Government (Miscellaneous Provisions) Act 1976 power is used and an SPV is not established, the electricity supply business will be carried on within the Council. This is the simplest route to follow but the local authority will be fully exposed to all regulatory, reputational and financial risk associated with the supply business. Local authorities using this route should also be aware that State aid rules apply to the financing of the electricity supply commercial venture, including the deployment of cheap debt available to a local authority (see section 6.5).

However, if a separate SPV is established (as is an option if the Local Government (Miscellaneous Provisions) Act 1976 power is used or a requirement if the Localism Act 2011 power is used), risk can be ring-fenced to some degree (in particular, financial and regulatory risk). Funding from the local authority will be subject to state aid rules (see section 6.4 and DPD guidance "Guidance on Powers, Public Procurement and State Aid"). It will also be possible to obtain third party commercial financing directly into the SPV and based on the electricity supply business case (which would not be state aid). However, the credit rating of the SPV will be a factor and guarantees may have to be given by the local authority to support any third-party debt and the giving of those guarantees would be subject to State aid rules.

If it is later considered desirable to sell off or to attract equity investment into part or all of an electricity business, some restructuring may be required depending on the nature and extent of the electricity business set-up. For example, if a local authority electricity business included some private wire connections and the private wire itself were to be sold off, the local authority electricity business may wish to hive off the private wire assets and put in place contracts (e.g. a use of system agreement) to retain access rights over the private wire. Exact requirements will be dependent on the circumstances and the objectives of the local authority. If restructuring is relied on to enable an exit or to attract equity investment, this will take time and resource and incur costs at the time and may lead to a sub-optimal tax impact. Therefore, where possible and appropriate, the 'exit strategy' should be considered from the outset, recognising that this is not always known and could increase initial set-up time and costs.

Specialist legal advice should always be sought.

8.4 Combining storage with heat networks

District heating schemes in GB are typically designed so that the combination of heat generating plant and network can meet maximum predicted heat load as it arises. Electricity is therefore seen as a by-product of using a CHP to generate heat. The CHP is run to reduce the notional carbon footprint of some associated properties, property development or refurbishment (which it does by contributing the production of low carbon electricity) and to provide some useful additional revenue.

This does not optimise the opportunity to generate revenue from heat and electricity because:

- the price charged for heat will nearly always be the same throughout the day; but
- the (potential) value of electricity generated varies throughout the day and so the (net) cost of producing heat from CHP varies.

8.4.1 Storage considerations

The balance between operating revenue and operating costs improves if electricity can be sold when it is most valuable (providing heat can be supplied when it is needed). Since the best time to generate heat and the best time to generate electricity do not always coincide, there is a role for storage to improve operational flexibility and the ability to maximise revenue.

It should be noted that heat and electricity can be stored so either (or both) have a potential role to play in a scheme, although, at present, heat storage is by far the cheapest technology to implement and is not subject to the regulatory complexity or uncertainty of electricity storage.

By making greater use of (most likely, heat) storage so that electricity can be generated or released more flexibly then, it may be possible to access:

- better prices for the electricity that is generated from a CHP;
- more embedded benefits associated with that electricity; and

- a wider range of additional revenue streams from ancillary services, including capacity payments (see Chapter 9, section 9.1.1.).

This potentially means that the 'energy business' can be run more profitably and/ or consumer prices can be kept lower.

However, the economics of a district heating scheme are rarely assessed purely on the basis of optimising the commercial operation of CHP and other energy plant. District heating schemes are usually tied in with property development or regeneration where a private developer (or a land-owning local authority prioritising land receipts) will place a premium on saleable or lettable space. This means that there is pressure to keep to a minimum the amount of space taken by energy plant and, as a result, heat storage may be constrained by both the space available and the opportunity cost of this space plus the minimum heat requirements that must be met.

What is considered 'optimum', therefore depends on perspective and objectives and, in turn, this depends on the role played in relation to a district heating scheme. Where a local authority takes on multiple roles, the optimum solution will depend on striking the right balance between all competing factors and emphasising elements appropriately in accordance with an identified hierarchy of objectives.

The Strategic and Commercial section of the DPD Guidance describes an approach to:

- identify and prioritise project objectives; and
- identify the role or roles the local authority wants and is able to play in respect of the scheme in question.

8.4.2 Other considerations

Other issues relevant to implementation of a CHP project include:

- land ownership – relevant to the siting of generating plant and any routes needed for pipe and wire runs
- planning and any other consents required (including under the Electricity Act, as discussed in chapter 6);
- construction, operation and financing
- connection to the distribution network
- other rights and obligations that may be relevant to the scheme.

Further information is available from the following sources:

- Draft Detailed Project Development Guidance Documents

8.5 Chapter summary

The high-level implementation notes within this chapter are designed to give an indication of the process and implementation issues associated with the eight routes to market. It also highlights some of the other major decisions than need to be considered to implement a project successfully. These may be commercial, regulatory or technical in nature. It is key that these issues are fully considered at the early stage of a project to ensure adequate appraisal of options is completed and resource allocated efficiently into those areas which yield greatest benefits. A summary of the timescales and resource implications of the routes to market is shown in the table below. These timescales represent the time to implement a route to market once a decision has been made and does not include construction of the CHP itself which is normally done in parallel.

Figure 39: Summary of timescales resource requirements for routes to market

Route to Market	Timescales	Resource Required

Self-Supply	1 – 6 months	LOW
Private Wire	6 – 21 months	MEDIUM
Full Licence	7 – 27 months	HIGH
Licence Lite	7 – 27 months	HIGH
White Label	6 – 20 months	LOW / MEDIUM
Sleeving/ Peer to Peer	6 – 19 months	MEDIUM
Synthetic PPA	6 – 19 months	MEDIUM
Standard PPA	2 – 12 months	LOW / MEDIUM

9 Other revenue sources

What is covered in this chapter?

This chapter describes the additional sources of revenue that may be available for a CHP project. The following topics are covered:

- Ancillary services income
- Capacity market income
- Balancing mechanism income
- Demand Side Response
- Role of Aggregators
- Eligibility criteria to qualify for income streams.

9.1 Other income streams

There are several income streams that may be overlaid on the business model for embedded generators. The ability of a CHP to earn revenue from these additional sources depends on the type of generator and the degree of flexibility that can be offered. This chapter considers four potential revenue streams that a CHP may be able to access in addition to selling its wholesale energy using one of the routes to market identified in these guidance notes. ***It should be noted that the regulatory regime is subject to change and that the value and/ or eligibility criteria for the income streams in this chapter are likely to change as a result. It is recommended that the most up to date position on potential regulatory changes in this area is assessed when considering a route to market.***

The income streams considered in this chapter are:

- Ancillary Services
- Capacity Market
- Balancing Mechanism
- Demand Side Response

9.1.1 Ancillary Services

Ancillary services are services provided by users of the system which are purchased by the System Operator (SO) to support the safe functioning of the electricity network, but are not procured through the purchase of electrical energy through the wholesale power market. They are therefore *ancillary* to the power market. National Grid (as the System Operator) must procure enough Reserve[87] and Response[88] to ensure the system can cope with the largest possible in-feed loss on the system and stay within its operational parameters, for example Sizewell B nuclear power station tripping off the system. There are currently a large number of ancillary services procured by the System Operator and these are currently under review[89] to determine what

[87] Reserve is the requirement by the System Operator to have access to sources of extra power in the form of either generation or demand reduction, to be able to deal with unforeseen demand increase and/or generation unavailability.
[88] Response services are required by the System Operator to manage system frequency which is a continuously changing variable that is determined and controlled by the second-by-second balance between system demand and total generation
[89] More information is available here: http://www2.nationalgrid.com/UK/Services/Balancing-services/Future-of-balancing-services/

services are required to meet the future needs of the system and whether existing services can be consolidated.

The payment structure for ancillary services reflects the fact that the services are not required continuously and normally contain an availability charge plus a utilisation charge. The generator will receive an availability payment regardless of whether it is called on to provide the service and the additional utilisation fee will only be received when the service is called. For a CHP, it should be noted that the generator must be in an available state to provide the service in the agreed availability windows. This is likely to impact on the provision of the heat requirements and is therefore unlikely to be an appropriate route to market for most CHP sites and should be considered as a possible revenue enhancement rather than a base case assumption.

The table overleaf summarises key information about the main ancillary services; Short-Term Operating Reserve (STOR), Firm Frequency Response (FFR) and Fast Reserve. These services are all mutually exclusive and a generator is unable to provide these services at the same time[90]:

[90] Some aggregators may contract with small generators to provide multiple services to enable them to optimise the sale of ancillary services to the System Operator. It may appear as though the aggregator is holding multiple ancillary services contracts covering the same period, but the aggregator will manage the contracts separately and allocate the requirement out to generators depending on the most economic method of meeting the contract obligation.

Figure 40: Ancillary services summary

Service	Short-Term Operating Reserve	Firm Frequency Response	Fast Reserve
Description	STOR retains generators on Standby over key periods of the day. STOR is split into three key services, Committed STOR, Flexible STOR and Premium Flexible STOR.	Firm Frequency Response is the automatic provision of generation or demand reduction in response to drops in system frequency. This is sub-divided into Enhanced, Primary, Secondary and High depending on response times and durations.	Fast Reserve is used to control frequency changes arising from sudden changes in generation or demand.
Eligibility	Need to be 3MW in size, or smaller assets aggregated to 3MW. All levels of connections can participate in STOR. National Grid requires dispatch within 240 minutes of notification, and strongly prefers generators that can dispatch within 20 minutes.	From April 2017 the minimum size is 1MW (previous minimum size was 10MW) Can be aggregated. Enhanced Response needs to be dispatched within 1 second[91]. 10 seconds for Primary and 30 seconds for Secondary. Duration is up to 30 minutes.	Need to be 50MW in size, or number of smaller projects aggregated to 50MW. Need to dispatch within 2 minutes for 15 minutes. Delivery rate must be more than 25MW/min.
Procurement & Contract Duration	National Grid holds two tender rounds each year between 2-24 months in advance of delivery for up to 24 months in duration.	National Grid holds a tender for this service monthly. Contracts offered by tender are no longer than 24 months and typically vary between 1 month to 12 months.	National Grid holds a tender for this service monthly. Contracts offered by tender are no longer than 24 months and typically 12 months.
Payments	STOR providers receive a £/MW/hr availability payment and a £/MWh utilisation payment. On average utilisation in STOR is around 4%.	FFR providers receive an Availability fee (£/hr) and a nomination fee (£/hr). There are optional fees for window initiation fees (£/window) and a response energy fee (£/MWh)	Fast Reserve providers are paid an Availability fee and Positional Payment in £/hour, a Window Initiation fee in £/window and a Utilisation payment in £/MWh.
Requirements	There is a reserve requirement of 2-2.3GW, and often 3GW is contracted. There are six irregular STOR seasons where generators can compete for morning and/or peak capacity windows.	Requirement varies by frequency response type. For static secondary and primary ~600MW. This varies by seasons and time of day.	National Grid procures 300MW over summer and 600MW over winter. It typically procures 300MW-400MW in the tendered Firm service.
Typical providers	Typical STOR providers include OCGT[92], Hydro, reciprocating engines and DSR.	Typical FFR providers include Pumped Storage, Hydro, DSR and reciprocating engines.	Typical Fast Reserve providers include Pumped Storage and Hydro.
Estimated value 2016-17*	£2/MW/h - £12/MW/hr	Primary £20/MW/hr Secondary £4/MW/hr EFR[91] £7/MW/hr - £12/MW/hr	£8/MW/hr - £13/MW/hr

* *The value of each service represents the average revenue received across all availability windows and assumes the generator is utilised at historical levels. The payment therefore reflects the availability fee that is paid when the generator is not running plus the utilisation fee that is received when the plant is called on to run.*

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[91] The technical requirements for Enhanced Frequency Response means it is unlikely that CHP would be able to provide this service

[92] Open Cycle Gas Turbine

The table below summarises the expected annual revenues for a site under each ancillary service, however the actual values that could be earned under these services could be influenced by many factors including, speed of response, availability over key windows, location and bidding strategy:

Figure 41 Estimated ancillary services annual revenue

Service	Short-Term Operating Reserve	Firm Frequency Response	Fast Reserve
Description	STOR is contracted for roughly 3,690 hours across the year. The estimated average utilisation rate for a STOR provider is 4%.	It is likely a CHP would only be able to provide secondary response because of the necessary response time. FFR can be contracted across the whole year, providers look to be available up to 24 hours. We have assumed an availability window of 16 hours.	A provider in Fast Reserve can expect to be nominated over 90% of available windows but could see utilisation around 5%. Contracts are typically for around 9 hours per day.
Estimated value	For a site seeking to hit Triad exports = 1MW X 2150 hours X £7/MW/hr £15,050 For a site seeking constant STOR availability = 1MW X 3690 X £7/MWh/hr £25,830	12 month FFR Secondary contract = 1MW X 5,840 (16X365) hours X £4/MW/hr £23,360	12-month FR contract = 1MW X 3468 (9*365) hours X £10.5/MW/hr £36,408

9.1.2 Capacity Market

The Capacity Market (CM) is a technology neutral mechanism for procuring a capacity volume designed to ensure the Loss of Load expectation in any year is less than three hours; i.e. the market has enough capacity to ensure electricity deliverability over 99.97% of the year.

Any plant greater than 2MW capacity, or a group of plant with a combined total of between 2MW and 50MW capacity, in Great Britain, is eligible to take part in the CM if it is not receiving support under the Renewables Obligation, the Small-Scale Feed in Tariff, the Contracts for Different FiT or Long-term STOR (Note: the System Operator suspended[93] the procurement of long-term STOR indefinitely, which is defined as STOR for a greater duration than two years, in 2012).

CHP and flexibility services

The Gateshead Energy Centre scheme has flexibility built in with backup heat provided through conventional gas boilers if the CHP is not available or it is not economic to run. Further flexibility is planned to be introduced in 2017 when the site will connect to a 3MW battery to enable electricity storage.

In early 2017, the scheme entered into an agreement with Flexitricity (see 9.1.8) to provide services to National Grid (Capacity Market and STOR). The inbuilt flexibility enables these services to be provided without a noticeable impact on the end customers. Gateshead estimate that this will result in additional revenue of over £60k per annum over the next 15 years.

For more details on the case studies see Appendix 1

The auction is open to providers of all types of capacity

[93] Long-Term STOR (Short Term Operating Reserve) Update: December 2012

including;

- Existing generation which can access 1 year contracts
- Refurbishing generators, which can access 3 year contracts
- New build generators, which can access 15 year contracts
- Demand Side Response
- Interconnectors

Auctions for capacity are held four years ahead of a delivery year (T-4), with further 'top-up' auctions to account for any interim changes one year (T-1) in advance of a delivery year. The auction utilises a "descending clock" format. The auction commences with a maximum price the auctioneer (National Grid) is prepared to accept, and a surplus of capacity to the target procurement volume at that price representing the total de-rated pre-qualified capacity. The auctioneer reduces the prices progressively in rounds. Each round will see £5/kW of total possible price decrements per round.

A provider whose unit clears in the auction has the right to receive a payment equal to the cleared auction price multiplied by their de-rated capacity. The de-rated capacity is a percentage reduction that is applied to the capacity of a power station to represent the typical availability for that type of plant. For the T-4 auction that took place for in 2016 for 2020-21, the de-rated value that was applied to CHP was 90.0%.

Example capacity market payment

The income for a 1 MW CHP plant successful in the T-4 auction that took place in 2016-17 would be:

Payment *= Capacity (1MW) x De-rating factor (90.0%) x kilowatts (1000) x clearing price (£22.5kW)*

= £20,250 per annum

The capacity market payments will be made to the generator in monthly instalments weighted by the level of overall electricity demand in each month i.e. greater payments will be received in winter when demand is higher than in summer when demand is lower.

The agreement obligates the provider to generate electricity over periods of system stress, defined as the System Operator disconnecting part of the distribution network under OC6 of the Grid Code. If they cannot do this they are penalised a 1/24th of the relevant clearing price, for every MWh missed, capped at 200% for any single event and 100% of annual revenues across the whole year. It should be noted that the obligation on a generator under the capacity market is to be generating at full capacity during the stress event. This does not mean that the capacity needs to be held back ready for a stress event as is the case with some reserve contracts. If the generator is already running at full capacity when the stress event is called, then it will be deemed to have met its capacity market obligation.

Three T-4 auctions have been held for four years in advance;

- In 2014 the auction for delivery in 2018/19 cleared at £18.9/kW
- In 2015 the auction for delivery in 2019-20 cleared at £18/kW
- In 2016 the auction for delivery in 2020-21 cleared at £22.5/kW

In addition, an early T-1 auction was held in 2017 for delivery in 2017-18 which cleared at £6.95/kW.

9.1.3 Revenue stacking

Revenue stacking is the concept of combining revenues from multiple sources for generating electricity from the same asset. Stacking is expected to help support investment in projects by providing additional sources of revenue beyond the core activity of the site.

There are four main sources of revenue considered during revenue stacking;

- Wholesale Power – This includes contracted power sold via the wholesale market or uncontracted power that is cashed out in the imbalance market and receives the imbalance price. For most embedded plant this distinction is not relevant as the power is sold via a PPA to a supplier who will provide a price for the power and manage any imbalance risk themselves.
- Ancillary Services – These services usually pay an availability fee for the generator providing reserve or response, and utilisation fees for energy provided during activation. They are usually exclusive over periods of availability
- Embedded Benefits – These are payments for exports of electricity at the distribution network at specific times, any export of power at the right time and place will be eligible to receive them
- Capacity Market – These payments are made separate to the export of energy to the network and can be received in addition to any other form of revenue other than renewables subsidies

The diagram overleaf shows where electricity revenues may be stacked or where constraints may exist.

Figure 42 Revenue stacking opportunities

Revenue source	Wholesale Power	Ancillary Services	Embedded Benefits	Capacity Market
Wholesale Power		Export of power is proscribed while providing ancillary services unless under instruction from the SO. While being utilised the power for export can sometimes be paid at the spill price.	Different embedded benefits can be earned on the same exported power.	Capacity Market payments can be received when exporting power to the wholesale market.
Ancillary Services	Export of power is proscribed while providing ancillary services unless under instruction from the SO. While being utilised the power for export can sometimes be paid at the spill price.	Most Ancillary services cannot be stacked with each other[94]	Export outside of instruction from the SO is forbidden while in ancillary services. Any power exported while under instruction to provide ancillary power can earn embedded benefits.	Capacity market payments can be received when participating in ancillary services.
Embedded Benefits	Export of power is proscribed while contracted to provide a ancillary service unless under instruction from the SO. While being utilised the power for export can receive embedded benefits dependent on location.	Export outside of instruction from the SO is forbidden while in ancillary services. Any power exported while providing ancillary power can earn embedded benefits.	Different embedded benefits can be earned on the same exported power.	Capacity market payments can be received while receiving embedded benefits
Capacity Market	Capacity Market payments can be received when exporting power to the wholesale market.	Capacity market payments can be received when participating in ancillary services.	Capacity market payments can be received while receiving embedded benefits	

RED – Revenue streams cannot be combined

AMBER – Revenue streams may be combined under some circumstances

BLUE – Revenue streams can be combined

[94] The exception to this is where a generator is contracted to provide black start services, they may also contract for other ancillary services subject to permission from National Grid

9.1.4 Balancing Mechanism

The Balancing Mechanism (BM) is a means for the System Operator (SO) to contract with parties for delivery of more ('buy') or less ('sell') power over short timescales to ensure the transmission system remains balanced and within operational limits. It is used alongside the ancillary contracts the SO also holds. Participation in the BM is mandatory for large scale generators with a capacity over 100MW, or generators connected directly to the transmission network. BM participation is optional for smaller embedded generators. However, the generator needs to become a signatory to the BSC and install systems to enable it to communicate with the System Operator. In practice, this is a costly exercise for smaller generators and not many embedded generators adopt this approach.

Participation in the BM will involve additional complexity and costs in comparison to an export only strategy. Compliance with the codes places responsibilities pursuant to the BSC and the Grid Code such as notification of trading positions and submission of Physical Notifications (plant operational dynamics) each half hour. The party is also directly exposed to the imbalance and settlement regime. The most significant cost will be the cost of the trading team required to analyse and notify participation in the Balancing Mechanism.

To participate in the BM a station will require a Balancing Mechanism Unit (BMU), which may require separate registration under the Central Volume Allocation service within the Balancing and Settlement Code (BSC), entailing new compliance requirements for an offtaker. This can be done through an existing offtaker or licensed supplier who can take on the code obligations and trading and optimisation surrounding Balancing Mechanism participation.

The rules of the BM are contained in the BSC. All licensed generators and suppliers are required to be party to and comply with the BSC. A market operator, known as Elexon, is responsible for administering the procedures in the BSC.

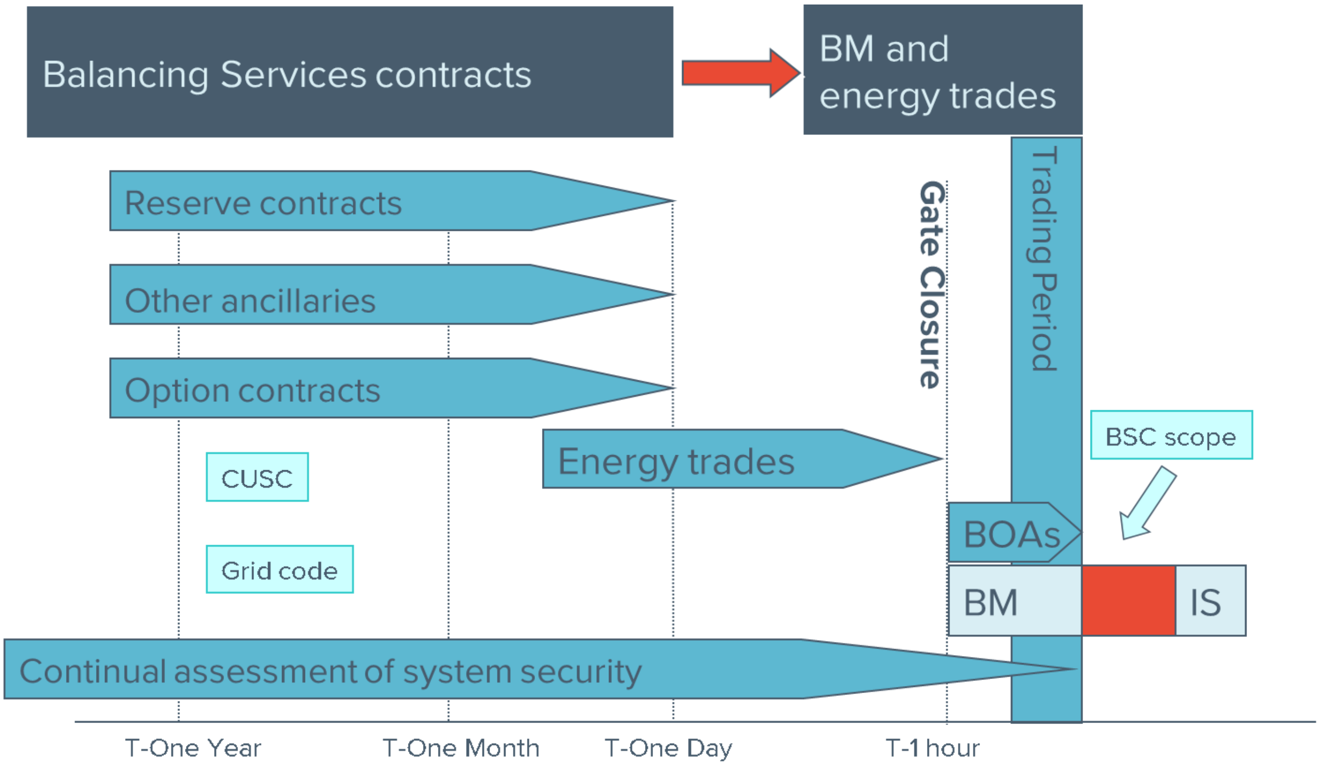
Under the code, a party's traded volumes are notified to the central trading systems. In practice this notification is to an agent of the central systems and occurs no later than one hour before each individual trading period[95]. This cut off point after which contracts cannot be registered is termed Gate Closure. The notified contracted position is used for the purposes of calculating energy imbalances. Contracts may be submitted at any time in advance of Gate Closure for the relevant trading period. In calculating volumes, the settlement administrator also considers any increases or reductions in energy committed to the SO through the BM.

At Gate closure participating generators have the option to submit bids (a series of prices at which the generator is willing to reduce their output) and offers (a series of prices at which they are prepared to increase output), as well as dynamic data such as ramp up and down rates, and other technical parameters to allow the SO to assess which plants can deliver the required services in the time and location required. Generators can submit up to ten bid offer pairs, which signal their availability to deviate from the notifications they provided to the SO at Gate Closure. The SO will then select the most economic bids and offers to balance the system considering the cost, flexibility, reliability and location of all the available options.

The diagram below provides an illustration of how the system operator balances the system by procuring a combination of different services. The balancing mechanism income reflects the actions taken by the System Operator within the actual half hour through the acceptance of bids or offers and is represented by the red rectangle:

[95] It should be noted that this timeline for the notification of contract volumes will be reduced to the beginning of the settlement period from November 2017 under BSC change proposal P342.

Figure 43 Illustration of the energy market and interaction with balancing mechanism[96]



Prices for incremental power provided in the Balancing Mechanism are usually higher than prices in the wholesale market as traders will consider the risk of not being called on and the extra cost of providing flexibility in the short-term.

9.1.5 Imbalance pricing

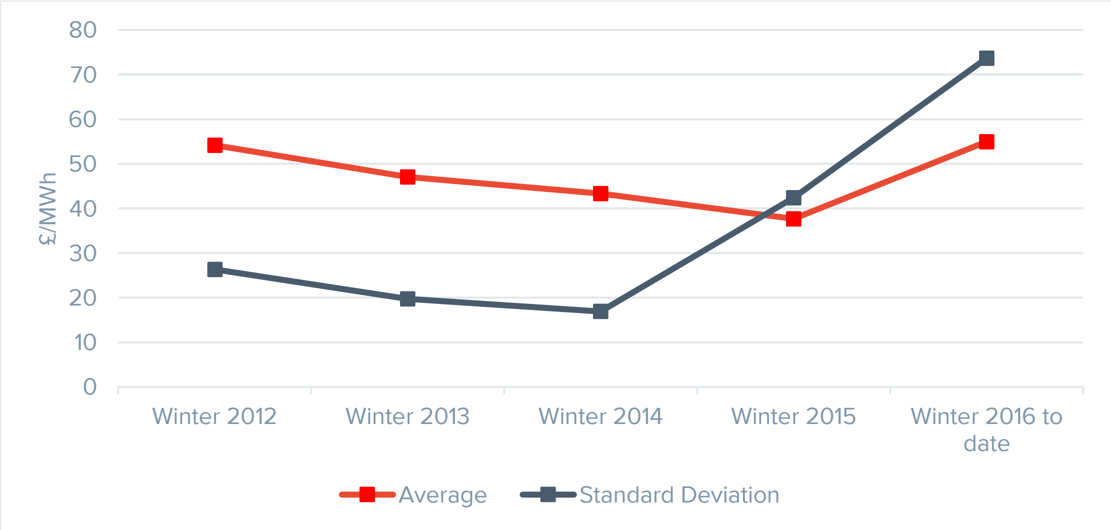
All parties that are signatory to the BSC (e.g. licensed suppliers and generators and a few large distributed generators) are exposed to imbalance prices on a half hourly basis. BSC parties submit their traded volume notifications at Gate Closure (presently one hour prior to the delivery of contracts). This figure is compared to the actual volumes of energy consumed (suppliers) or produced (licensed generators) by reference to metering data. Where a difference exists, the party will face imbalance charges on those volumes.

The Single Imbalance Price[97] (SIP) is paid to parties that have over-contracted (e.g. a long position) and is paid by parties that have under-contracted (e.g. a short position). The SIP is calculated for each half hour settlement period and although the price formation is complex it is based on the 50MWh most expensive actions taken by the SO in the balancing mechanism in that half hour. As the short-term provision of services in the BM are typically priced higher than can be achieved in the wholesale market this tends to result in SIPs being more expensive to BSC parties compared to what they could have achieved in the wholesale market.

The diagram below details the average SIP during winter. The figure also shows the spread of system prices (measured using standard deviation), which is increasing, demonstrating the volatility of the value in this part of the market and how offering short-term flexibility can provide higher rewards for certain plant.

[96] BOA = Bid Offer Acceptance, CUSC = Connection and Use of System Code, BM = Balancing Mechanism, IS = Imbalance Settlement
[97] Prior to November 2015, the imbalance price consisted of a separate buy and sell price. This was changed to a single price that applies to parties that need to buy and sell volumes following a review of the balancing mechanism by Ofgem.

Figure 44 Winter system price average and standard deviation



9.1.6 Demand Side Response (DSR)

For a CHP that is connected behind the meter, the electrical output of the CHP will impact on the level of demand taken by either the self-supply consumption or the consumption of the customer on the private wire. The CHP output can therefore by used in conjunction with the demand to alter the level of consumption and allow the demand reduction to be sold via a DSR service. This means that the provision of DSR services by a CHP is most applicable for a direct route to market as the output from the CHP will offset demand and provide flexibility to vary the level of demand in response to market signals.

Ofgem defines DSR as actions by customers to change the amount of electricity they take off the grid at particular times in response to a price signal. This is also known as “transactable demand-side response”, where a customer chooses how to change their electricity consumption either by themselves or by agreeing to let someone else alter or manage their consumption. DSR is all about extracting value from the inherent flexibility that customers have within their electricity consumption. Often, the customer is not even aware that this flexibility exists or that it could create a revenue stream with little upfront investment.

There are two form of DSR, proactive and reactive and a DSR provider can be active in both forms. Reactive DSR is where an energy company produces a cost reflective price signal and the end customer adjusts their consumption in response. A proactive DSR initiative is where an energy company actively seeks out an agreement with an individual customer or group of customers to amend their electricity consumption to benefit the energy company, with the benefits shared with the customer.

There are multiple opportunities for revenue streams from different forms of DSR, including wholesale price arbitrage, embedded benefits, ancillary services and the Capacity Market. Proactive forms of DSR can attract higher value than reactive DSR and there is inherent optionality to prioritise different sources of revenue dependent on prevailing market conditions.

9.1.7 Implications of providing flexibility services

The provision of flexibility services, whether through an ancillary service, a DSR agreement or price arbitrage through a PPA will require the generator to operate in a certain way. For ancillary services, there will be technical requirements that must be met to enable the generator to bid to provide these services. All flexibility services will require the plant to ramp up and down more frequently than it would otherwise do in normal operating mode. This will place additional stress on the generator that ***could lead to more unforced outages over the longer term*** (due to the thermal expansion and contraction that takes place as the load varies). Consequently, any additional income generated through the provision of flexibility services needs to be balanced against the additional cost of the unforced outages in terms of cost to maintain the asset, opportunity cost of lost revenue and cost of providing heat to end customers when the CHP is unavailable.

Maintenance Costs

The Pimlico CHP engines were originally run across the daytime periods and switched off overnight, but the operator changed operation to run the plant 24 hours a day with any excess heat stored in a large thermal store. This was in part to increase revenue, but the operator also stated that the continual running reduced maintenance requirement as the engines were not stopping and starting, avoiding thermal cycling and hence stress of components.

For more details on the case studies see Appendix 1

9.1.8 Role of Aggregators

An aggregator can help facilitate customer access to a range of generation or demand side flexibility services by aggregating many small volumes together to meet the minimum participation volumes for many services. The role of aggregators has grown in terms of the number of operators, the number of schemes they participate in and the scale of customer participation. Aggregators focus particularly on ancillary services markets; they cannot typically directly access potential benefits for their customers in the wholesale markets, as most are not currently Balancing and Settlement Code (BSC) signatories. The Capacity Market is also a popular route to market for aggregators as the scheme allows smaller units to be aggregated together to meet the minimum 2MW size, although the maximum sized of aggregated units in the Capacity Market is 50MW.

At time of publication, there were 19 aggregators recognised by National Grid, listed below. An up to date list, which includes contact emails for each organisation can be accessed on the National Grid website here.

Figure 45: Current list of aggregators

Company
Actility
Ameresco Limited
EDF Energy
Endeco Technologies
Energy Pool / Schneider Electric
EnerNOC UK Ltd
E.ON Connecting Energies GmbH
Flexitricity
Engie (previously GDF SUEZ Energy UK)
KiWi Power Ltd
Limejump Ltd
Npower Ltd
Open Energi
Origami Energy Limited
Pearlstone Energy Limited
Reactive Technologies
REstore
Stor Generation Ltd
UK Power Reserve Ltd

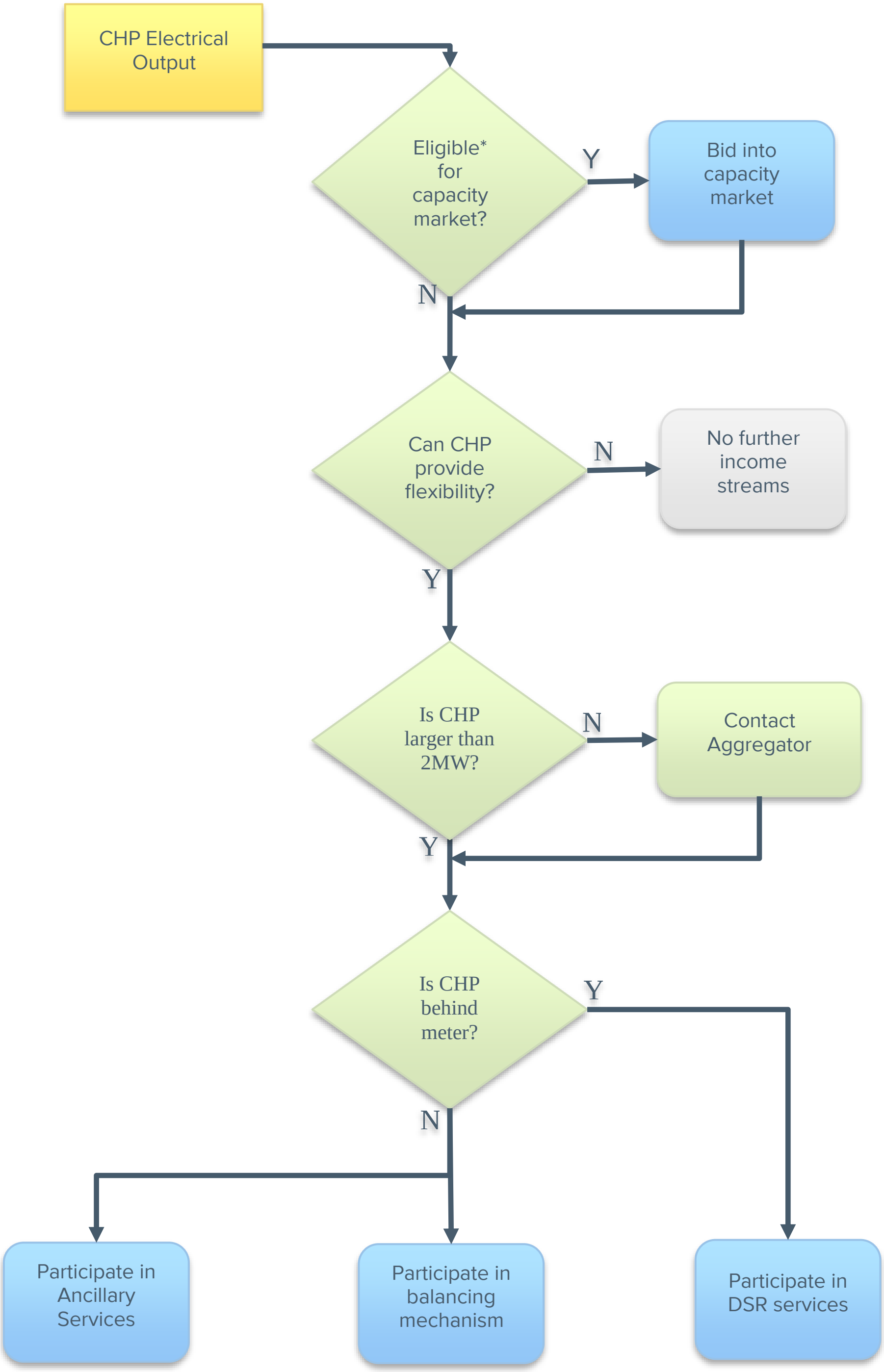
9.2 Chapter summary

This chapter has outlined the potential sources of income that are available to a CHP in addition to the revenue received for their wholesale energy through the routes to market contained within these guidance notes. The most accessible of these revenue streams is the Capacity Market income that can be earned without any impact on wholesale revenue or any investment in additional systems. The only constraint is that the CHP is not receiving a subsidy through the schemes set out in section 9.1.2 and is therefore eligible to participate. A further consideration is that if the CHP is under 2MW it will need to be aggregated to allow it to participate.

The other income streams that are available to CHP are reliant on the ability to offer flexibility services to the System Operator. This is either through ancillary services, the balancing mechanism or DSR. Where it is possible for a CHP to offer flexibility services, it is important to assess the impact this may have on the obligations for the provision of heat that may constrain how much flexibility can be provided. In practice, most CHPs do not participate in these markets due to the obligation to provide heat.

The diagram below provides a high-level decision tree for CHPs considering the options for earning additional income:

Figure 46: Potential for CHP additional income



* Generators are not eligibile to participate in the capacity market if they receive subsidies elsewhere (see 9.1.2 for more information). The capacity market also specifies a minimum size for direct participation (2MW), but allows smaller generators to be aggregated.
* Generators are also eligible to participate in the capacity market if they are situated behind the meter. This is likely to require additional metering to ensure the generator meets its capacity market obligation.

10 The Regulatory Environment

What is covered in this chapter?

This chapter looks at potential regulatory change and the potential impact split into the following categories:

- Embedded benefits
- TNUoS demand charges (Triad)
- Small generator discount
- Capacity market
- Behind the meter generation
- Brexit

The route to market for the electrical export from a CHP will depend not only on the revenue that can be earned under the current regulatory regime, but must also take account of potential regulatory changes that may impact on revenue streams in the future. There are currently a number of industry reviews underway plus a large number of proposed changes to industry codes, all of which could result in changes to network charges and ultimately impact on the business model chosen for the development of a CHP.

This section highlights the potential regulatory changes that may occur. **It should be noted that there is considerable uncertainty about the outcome of many of the changes identified in this section and care should always be taken to ensure the most up to date position is identified when developing a business model for a potential CHP project**. Furthermore, any regulatory change that may emerge is likely to have consequential impacts in other areas due to the complex and inter-related structure of the electricity industry.

10.1 Embedded benefits

Ofgem have been reviewing the transmission network charging arrangements for embedded generators since January 2016. Ofgem are concerned that the level of embedded benefits may be over-rewarding embedded generation and leading to market distortions, particularly within the Capacity Market. The review of embedded benefits by Ofgem may result in a reduction in value for these revenue streams and this chapter considers the regulatory risk that currently exists in this area. It is recommended that stakeholders ensure they are aware of the most up to date position on any regulatory change which may impact on the investment case for a CHP project.

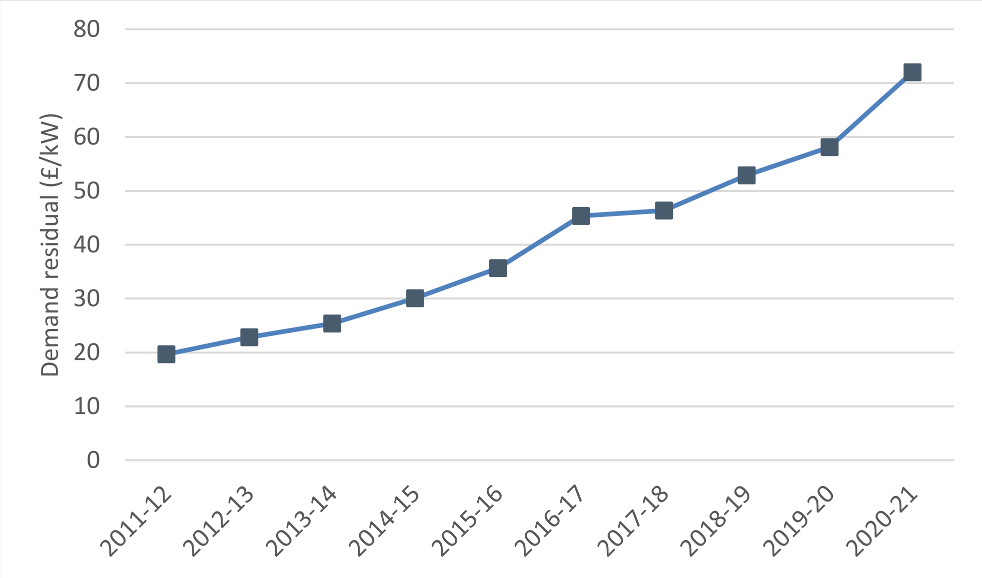
10.1.1 Triad Benefit

The Triad benefit consists of two elements as follows:

- Locational charge – represents the incremental cost associated with different locations on the network
- Residual charge – the additional charge in £/kW that is added to the locational charge to ensure National Grid recovers the correct revenue. This charge does not vary by location.

The residual charge recovers the bulk of the transmission use of system revenue and has increased substantially over recent years. The chart below shows how the Triad residual has increased since 2011-12 and how it is forecast to increase out to 2020-21.

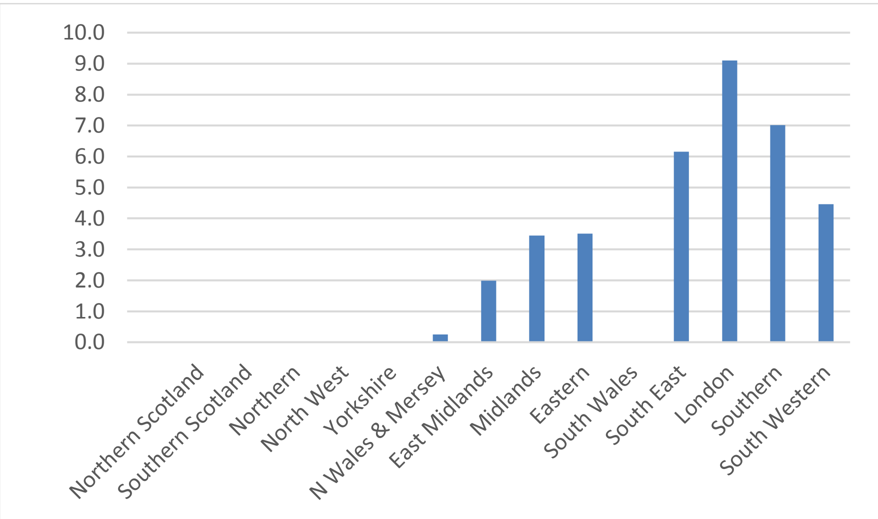
Figure 47: Demand residual component of Triad charge (Source: National Grid)



The level of the demand residual has been identified by Ofgem as a priority issue due to the rapid increase in value that has been seen in recent years and which is expected to continue in the future. Ofgem are looking at two existing CUSC[98] change proposals (CMP 264 and 265) to bring forward a solution to enable Ofgem to address the issue in a timely manner. On 22 June 2017, the regulator published a decision on CMP 264 and 265 that reduces the value of the Triad residual for embedded generation to the value of the avoided reinforcement costs at a Grid Supply Point (GSP). National Grid have estimated the likely range of the avoided GSP reinforcement cost at between £3/kW and £7/kW and will publish the value to be used for charging purposes in September 2017.

The decision will have a phased implementation from April 2018, with full implementation expected in April 2020. The low Triad residual could result in negative charges in some DNO areas, so the decision floors the charge at zero. This means that the Triad benefit will either be zero or a small credit once it has been fully implemented. There are no grandfathering arrangements under the decision. The chart below shows the forecast level of the Triad benefit in the charging year 2020-21:

Figure 48: Indicative Embedded Export Credit in 2020-21 (£/kW)[99]



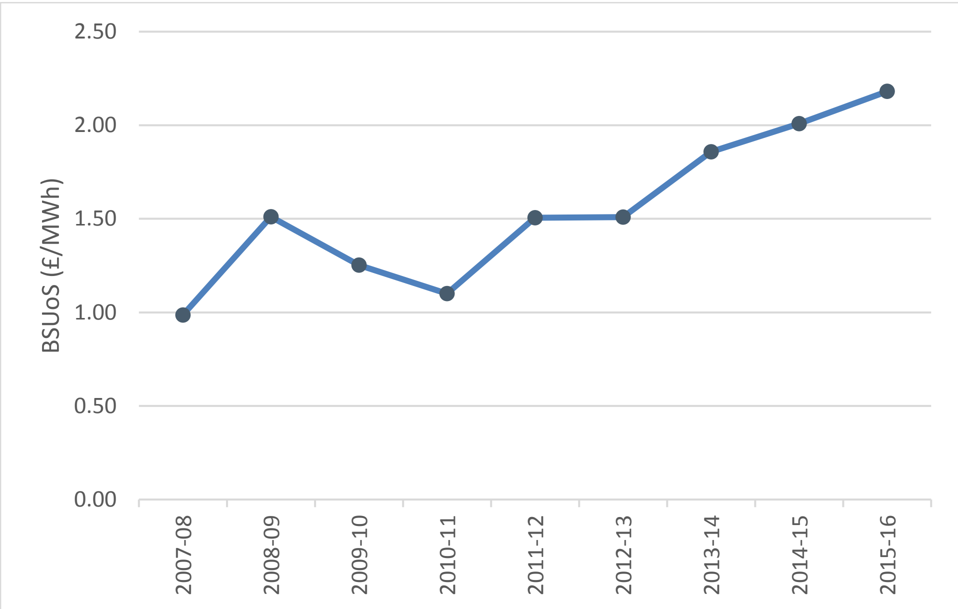
[98] Connection and Use of System Code
[99] Source: National Grid 5 year TNUoS tariff forecast

10.1.2 Balancing Service Use of System (BSUoS)

BSUoS is a charge that is levied at transmission level on both transmission connected generation and all licensed suppliers. As embedded plant offset supplier demand from the transmission system they effectively receive a credit for supplier's avoided costs. This is passed back to the embedded generator in a PPA.

BSUoS charges have increased over time, but not at the same rate as the Triad benefit. The increase is due to a combination of a reducing charging base, the System Operator having to work harder to manage a system with increasing levels of intermittent generation, and managing system constraints (the biggest component of BSUoS, largely driven by insufficient transmission network capacity to move power from Scotland to England). The constraint cost elements of BSUoS are expected to reduce in the future once the new Direct Current (DC) transmission lines (referred to as "bootstraps") between Scotland and England are built. The graph below shows how BSUoS has grown since 2007.

Figure 49: Average BSUoS by year



BSUoS has been identified as an area of concern for two reasons:

- Embedded plant, particularly that which is intermittent, is driving an increase in BSUoS by reducing inertia and contributing to the requirement for flexibility services.
- Transmission connected plant pays a BSUoS charge and embedded plant receive a credit, potentially resulting in market distortions

10.1.3 Transmission Losses

Transmission losses are applied at the transmission network level on an average basis across GB. BSC parties pay for the 'lost' energy via the wholesale market. The Competition and Market Authority (CMA) investigation[100] found that applying transmission losses on an average basis is having an adverse impact on competition and has recommended a move to seasonal locational transmission losses. The implementation of this change is underway through BSC change proposal P350. This is a mandated change by the CMA with an implementation date of 1 April 2018 and has been approved by Ofgem.

[100] CMA investigation: https://www.gov.uk/cma-cases/energy-market-investigation

10.1.4 Generation Distribution Use of System (GDUoS)

GDUoS varies by location, connection voltage, and type of generation. There are two charging methodologies for the calculation of GDUoS as follows:

- Common Distribution Charging Methodology (CDCM) – Sets charges for Low Voltage and High Voltage customers
- Extra high voltage Distribution Charging Methodology (EDCM) – Sets charges for Extra High Voltage (EHV) customers

Under the CDCM, all generators connected at LV and HV receive a unit based credit. For intermittent generators, this is a single unit rate and for non-intermittent generators it consists of three unit rates in different timebands (red, amber and green). The credits tend to be larger at a lower voltage of connection.

Under the EDCM, only non-intermittent generators receive credits and even then, it is only if they can be shown to assist the network by providing network security. The credits, where applicable, are applied only during the super-red timeband (which varies by DNO) and at no other time. The credits are determined on a site-specific basis and therefore will be unique to that site. The generators may also incur a capacity charge and fixed charge.

There are several DCUSA[101] changes that may result in higher or lower credits for generators. DCUSA change proposals (DCPs) 268, 274, 283 and 287 could all potentially have an impact on the level of credits. In addition, the DNOs are currently undertaking a review of the CDCM and EDCM methodologies that could result in further changes being brought forward. A particular concern of DNOs is that where networks are becoming saturated with embedded generation, the possibility arises that the networks become generation dominated and consequently embedded generation could receive a credit while driving costs for the DNOs.

10.1.5 Capacity Market Supplier Charge (CMSC)

The CMSC recovers the cost of the capacity market from licensed suppliers. In 2016-17 the CMSC was low as the capacity market was only recovering its set up costs. However, in 2017-18 it will increase substantially to recover the full capacity market costs. The application of this charge to net demand creates a benefit to embedded generators who can assist suppliers in offsetting this charge. However, unlike TNUoS and BSUoS, suppliers only benefit from a reduction in the CMSC if they have demand to offset the embedded generation against. In addition to this, existing embedded generators will only receive the CMSC as an embedded benefit if their existing Power Purchase Agreement (PPA) facilitates the pass through of the benefit. The CMSC as an embedded benefit will accrue to generators who export between 4 and 7pm on weekdays, November to February each year.

DECC (now BEIS) has highlighted that if embedded generation can receive the CMSC as an embedded benefit this could create a market distortion as embedded generators can receive a double benefit by winning a capacity market contract and then receiving a credit for avoiding the recovery of the capacity market costs.

10.1.6 Other embedded benefits

The remaining embedded benefits not considered above are distribution losses and Assistance for Areas with High Electricity Distribution Costs (AAHEDC). Neither of these embedded benefits are subject to regulatory change at present.

[101] Distribution Connection and Use of System Agreement (DCUSA). This is the industry code that determines charges for use of the distribution networks.

10.1.7 Ofgem proposed Targeted Charging Review

On 13 March 2017, Ofgem published a consultation[102] on a planned Targeted Charging Review (TCR). The TCR is proposing a Significant Code Review (SCR)[103] which will primarily focus on the recovery of residual charges for networks. Ofgem defines residual charges as follows:

"*residual' charges are the 'top up' network charges which ensure network companies can recover their allowed revenues once other charges are collected. These charges do not specifically recover particular network costs, but relate to the 'joint' or 'common' costs of the existing networks that can't be attributed to individual users' usage of the network.*"

This review will include an assessment of the residual charges at transmission and distribution. It also considers whether BSUoS is a residual charge and should form part of the SCR. The TCR is aiming to address the concern that the residual is not a forward looking cost element but is currently incentivising people to act in a certain way.

Ofgem's initial view is that all users should make a contribution to common costs and propose five options which will be looked at as part of the TCR which are set out below:

- Option A: a charge linked to net (kWh) consumption
- Option B: a fixed price charge
- Option C: fixed charges set by connected capacity
- Option D: gross kWh consumption
- Option E: a hybrid approach

10.1.8 Summary of embedded benefits impacts

The table below provides a summary of the possible changes in embedded benefits.

[102] Ofgem consultation of a Targeted Charging Review
[103] The Significant Code Review (SCR) is a mechanism for industry code rule changes that allows Ofgem to play a more active role in driving through changes required to deliver wider market and policy aspirations.

Figure 50: Embedded benefits and regulatory change

Revenue stream	Rationale	Likely implementation date
TNUoS (Triad benefit)	Ofgem's decision on CMP264/5 sets the value of the Triad benefit at the locational charge plus the avoided GSP infrastructure costs (estimated at between £3/kW and £7/kW). This will lead to a substantial reduction or the complete removal of the Triad benefit, depending on location.	April 2018 (phased in over 3 years)
GDUoS	There are a number of proposed changes to the methodology plus a fundamental review of the CDCM and EDCM is underway. These changes could impact on the level of credits awarded to embedded generation either positively or negatively and at present there is no clear direction on future credits.	N/A
BSUoS	Ofgem has raised the issue that embedded plant may be benefiting from BSUoS while driving costs. In addition, Ofgem are concerned that transmission connected plant pay BSUoS while embedded plant receive a credit which may be leading to market distortions. Ofgem plan to examine this issue along with their review of flexibility.	Medium term (3-5 years)
Transmission Losses	Transmission losses will be impacted by change proposal P350 which introduces locational transmission losses as directed by the CMA. The impact will be positive or negative for embedded plant depending on their location.	April 2018
CMSC	BEIS are consulting on removal of this embedded benefit from April 2018 to avoid embedded generation being rewarded twice through the capacity market and then again through the avoidance of the CMSC.	April 2018
Distribution Losses	No regulatory change envisaged	N/A
AAHEDC	No regulatory change envisaged	N/A

10.2 TNUoS demand charges (Triad)

There are two CUSC change modifications (CMP 271 and 274) that are proposing to amend how TNUoS charges are set for demand customers. These modifications propose that the Triad charge for demand should be reduced as most of the cost components are sunk and cannot be impacted by demand customers reducing their load during the triad period.

These two change modifications propose to amend the Triad calculation so that only the locational element (or a subset of the locational) is recovered via the Triad mechanism. The remaining costs are spread across either all half hours (CMP 271) or in the peak periods between November and February for CMP 274[104].

The change modifications will only impact on demand customers and therefore they have a consequential impact on behind the meter generation. The impact of these changes will depend on the running regime of the CHP. Where a CHP runs at baseload, it can expect to capture a similar amount of revenue as it currently does under the existing Triad regime. However, where the CHP runs to capture peak electrical demand, a reduction in this embedded benefit can be expected as some of the income will not be realised.

10.3 Small generator discount

The definition of transmission differs between Scotland and England and Wales. In Scotland 132kV is considered transmission whereas in England and Wales it is distribution. Plant under 100MW that is connected to the distribution network is entitled to receive embedded benefits. However, a plant under 100MW in Scotland at 132kV will be exposed to transmission charges, and so will see different charges to similar plant in the rest of GB.

An interim solution to this was implemented by Ofgem via a “small generator discount” from April 2005. This is a rebate to transmission charges for generators less than 100MW that are transmission connected in Scotland but would have been distribution-connected in England and Wales. The aim of the discount, set out in the transmission Standard Licence Condition (SLC) C13, was to avoid discrimination and create a level playing field between under 100MW 132kV transmission connected generators in Scotland and those that are distribution connected at 132kV in England and Wales. The discount was set for three years starting in 2005, with a view to reviewing the charging arrangements and developing enduring arrangements for charging distributed generators. The level of the discount was set at 25% of the combined generator and demand residual tariff and has remained calculated according to that formula throughout its existence.

The discount has been extended a number of times and most recently was extended to 31 March 2019. In its most recent extension Ofgem said that, in respect of analysis by National Grid for its informal review of embedded benefits, it did not consider that the evidence allowed it to reach a view on whether letting the discount expire is more cost reflective than continuing with the discount.

The discount was expected to be worth £3.67/kW for the first year starting 1 April 2005 and will be worth £11.46/kW for 2016-17.

[104] The proposed time period is 06:30 - 10:30 & 16:30 - 20:30, Monday – Saturday (excluding bank holidays) between November and February

10.4 Capacity Market

The Capacity Market may be a source of income for a CHP if it meets the eligibility criteria set down in the rules. There are two sources of regulatory risk in relation to the capacity market that stakeholders should be aware of:

- Changes to the eligibility capacity market rules
- Changes to rules elsewhere that impact on the capacity market clearing price

At time of publication there are no proposed changes to capacity market rules that directly impact on CHP. A potential area that could arise in the future is the ability of generators to revenue stack between different services and whether this could enable or prevent a CHP's participation in the capacity market.

10.5 Behind the meter generation and private wire

Ofgem have expressed concern in their TCR that changes to the charging arrangements for embedded benefits could incentivise more generation to connect behind the meter or via private wires. Private wire and self-supply mean that embedded generation is less visible to the System Operator and that costs such as network costs and subsidies for renewables are not recovered from customers making use of behind the meter and private wire generation. Where this occurs, there is a potential for charges to increase for the customers that are supplied over the public network (e.g. via a licensed supplier that is exposed to these costs).

The regulator stated in its TCR consultation that it has '*no specific concerns with the current licence exemption arrangements. Nor would seek to prevent individual consumers, or groups of consumers and generators, from taking their own decisions about how to manage their energy use or generation*'. This suggests that at the present time, the regulator has no plans to change the current licence exemption arrangements. However, the options under consideration to change the way in which residual network charges are recovered from customers will impact on behind the meter generation and private wire arrangements. This is because Ofgem propose that the residual element of network charges could be recovered on a fixed, capacity or gross basis to ensure all consumers who are connected to the distribution and transmission networks make a contribution towards them (as discussed in section 10.1.7).

10.6 Brexit

At time of publication there is no visibility on how future policy may change once Brexit occurs. The Business, Energy and Industrial Strategy (BEIS) Committee launched an inquiry in November 2016 to examine the implications of the UK's departure from the EU on the energy sector and the UK's national climate change commitments. The inquiry was to determine which policy areas should be prioritised for continued cooperation during the exit negotiation process.

10.7 Impact assessment

A direct route to market either through self-supply or a private wire arrangement generally reduces the risk associated with regulatory change. This is because under these routes to market the electricity produced is used to offset demand charges and does not enter the public network. Any changes to regulatory rules that impact on embedded generation only effects those generators connected to and spilling onto the public network. Any generation that sits behind the meter is only impacted by a change to the regulatory rules to the extent it impacts demand charges.

A good example of this is the decision to reduce the Triad demand residual as it is applied to embedded generation which will significantly reduce the Triad benefit for all embedded generation. However, behind the meter generation will be able to capture the full Triad charge as it is applied in full to demand customers and behind the meter generation will therefore be able to offset it.

The table below provides an indication of the impact of regulatory change on the route to market for self-supply or private wire arrangements:

Figure 51: Impact of regulatory change on direct routes to market for CHPs

		Potential Impact of Change		
	Likelihood of change	**Direct Route** *(Self-Supply/ Private Wire)*	**PPA Route** *(Standard PPA Sleeving/ Peer to Peer/ Synthetic PPA)*	**Supply Route** *(White Label/ Licence Lite/ Full Licence)*
Embedded Benefits	HIGH	LOW	HIGH	HIGH
Triad Charge (for demand)	MEDIUM	MEDIUM	LOW	LOW
Small Generator Discount	MEDIUM	LOW	MEDIUM (SCOTLAND ONLY)	MEDIUM (SCOTLAND ONLY)
Capacity Market	LOW	LOW	LOW	LOW
Behind the meter	HIGH	HIGH	LOW	LOW
Brexit	MEDIUM	LOW	LOW	LOW

10.8 Chapter Summary

Regulatory uncertainty for embedded generators is likely to persist for a number of years. It is recommended that any stakeholders looking to become involved in a potential CHP project ensure they have the most up to date information that is available at that time and that the route to market for the electrical export from the site takes account of the regulatory changes that have been made or may be undertaken in the future.

Appendix 1 - Case studies

This section provides case studies to highlight practical considerations of installations to demonstrate different approaches and objectives adopted by developers.

Pimlico District Heating Undertaking

Project: Combined Heat and Power Project

Electrical Capacity: 3.2MW

Fuel Source: Natural Gas

Route to Market: Power Purchase Agreement (PPA)

Built in 1950 to distribute waste heat from Battersea Power Station, the Pimlico scheme was the UK's first large, CHP-based district heating network. With closure of the power station in the 1980s, the network was restored to CHP operation in 2006 with the installation of two gas engines. Having a total capacity of 3.2MWe, they supply the network's baseload heat requirement. Three 8MW boilers provide winter peak requirements and standby.

The CHP engines were originally run across the daytime periods and switched off overnight, but the operator has recently changed operation to run the plant 24 hours a day with any excess heat stored in a large thermal store. Besides increasing revenue, the operator stated that the continual running reduced maintenance requirement as the engines were not stopping and starting, avoiding thermal cycling and hence stress of components.

The operator uses historic data to create a half-hourly generation output profile that is at the core of the invitation to tender for suppliers to purchase export via a Power Purchase Agreement (PPA). This should also include information on planned outages for maintenance. Recent experience has shown that tendering an annual PPA contract results in the most attractive prices, primarily due to the relatively large number of offtakers willing to price a contract.

Although offers are likely to give different values for specific revenue streams such as embedded benefits and power prices, the operator prioritises the total value, which can readily be modelled, when selecting a counterparty.

The operator noted that the larger energy companies tended to have less stringent PPA terms and conditions, presumably because unforeseen breakdown and shortfall in generation is less significant when it occurs alongside a large fleet of contracted generators.

Gateshead Energy Centre

Project: Combined Heat and Power Project

Electrical Capacity: 4MW (comprising 2 x 2MW engines)

Fuel Source: Natural Gas

Route to Market: Private wire

Gateshead Council opened the Gateshead Energy Centre in March 2017 to provide heat and power to the district energy network across Gateshead town centre and the Gateshead Quays area. This £18m project generates both heat and power for sale directly to customers via a new 3km underground network of heat pipes and high voltage ‘private-wire’ electricity cables.

The scheme is currently supplying public buildings and homes managed by the Gateshead Housing Company, but plans to extend the network to supply commercial developments and more housing estates in the future. The scheme was originally planned around the public buildings as this provided a secure long term offtake for both heat and power and added certainty into the business plan.

The scheme was funded and owned by Gateshead Council and is operated by Gateshead Energy Company, a limited company wholly owned by Gateshead Council.

Gateshead selected a private wire route to market as it increased the electricity revenues received under the project. They initially looked at sleeving as a cheaper way of capturing the higher revenues, but realised that this only applied to the wholesale price, whereas a private wire approach allowed the project to capture the higher retail price. Any excess electricity is exported to the public network and sold via a PPA. The scheme is managed under exemptions from holding electricity supply and distribution licences, so that power can be sold directly to public and commercial customers without the requirement for a licence.

The scheme is selling power to existing customers who were previously connected to the distribution network. To avoid duplication of network assets, Gateshead have agreed with the DNO to acquire the local distribution network assets required to enable the private wire to connect directly to these customers. The sale of these assets has been approved by Ofgem. Gateshead highlight the importance of establishing a good relationship with the DNO to help progress the project in a timely and efficient manner that benefits both parties.

The contractual arrangements with the end customer means customers are signed up for longer term deals (up to 20 years) and in return receive a minimum discount of 5% on the prevailing market rate for their heat and power costs compared to buying direct from the market.

The scheme has flexibility built in with backup heat provided through conventional gas boilers if the CHP is not available or it is not economic to run. Further flexibility is planned to be introduced in 2017 when the site will connect to a 3MW battery to enable electricity storage. Gateshead also suggest that the scheme has the potential to enter “island mode” at a later date where the network could detach itself from the public network and become completely self-sufficient.

In early 2017, Gateshead further enhanced the revenues that can be achieved under the scheme, by entering into an agreement with Flexitricity to provide services to National Grid (Capacity Market and STOR). The inbuilt flexibility enables these services to be provided without a noticeable impact on the end customers. Gateshead estimate that this will result in additional revenue of over £60k per annum over the next 15 years.

Gascoigne Estate District Energy Scheme

Project: Housing Regeneration Project with a District Energy Scheme using a site wide heating and electricity network and Gas Fired CHP

CHP Electrical Capacity: 800kW

Fuel Source: Natural Gas

Route to Market: Private wire

The London Borough of Barking and Dagenham has set up B&D Energy Limited (as a wholly owned ESCO) which will develop a number of low carbon and renewable energy projects across the borough. These include the development of a district energy scheme to deliver electricity and heat to the Gascoigne estate which is currently being regenerated by the Council. The project is based around 800kW CHP (2 off 400 kW units) that will supply heat and power to around 1,000 properties and two schools.

The original plan was to sell the power onto the public network via an electricity supplier using a standard PPA arrangement. Once the other options were fully assessed, it soon became clear that a private wire arrangement produced a much higher Internal Rate of Return for the project and lower electricity prices for end consumers. In addition, providing power to domestic customers was found to be more beneficial than selling to commercial properties as domestic customers tend to pay a higher rate for their electricity, although supplies will also be made to the two schools.

The authority has secured a single grid connection from UKPN to connect to this private site wide network. From the UKPN substation on the site all electricity cabling and switchgear downstream of this up to each consumer will be owned by the Council as a private network and operated by B&D Energy Limited. The CHP sits between this connection to the DNO and the end customers. Consequently, the CHP will provide all the power requirements needed by the customers with any top up required, supplied to the private wire network from the public network and sold on to the end customers. Likewise, if there is too much power, it can be spilled onto the public network if required.

B&D Energy will be responsible for the supply of power and heat to the individual customers. These customers will have heat and electricity meters installed and agreements for the supply of electricity and heat with B&D Energy. B&D Energy are finalising billing arrangements to allow the administration of these contracts. The aim is to provide the customers with a discount on the market rate they would otherwise expect to pay for their electricity. It was noted that under the current third party access arrangements, the customers could move to an independent supplier if they could achieve a lower price than that provided by B&D Energy Ltd.

It was noted that the sale of electricity is utilising the exemptions from having to hold a supply licence. They highlighted that these exemptions are ambiguous and confusing and they sought legal advice to ensure the exemption was valid for the planned development.

The planned operating regime is that the CHP will run at relatively flat profile across the day in conjunction with a thermal store Depending on heat loads the CHP may be switched off overnight if this is economic.

Appendix 2 – Detailed description of Routes to Market

This appendix provides detailed information about the routes to market for the electrical export from CHP plant. There is a separate section for each of the routes to market identified. Please click on the links below to navigate straight to the section you are interested in:

Category	Route to Market
Non-settlement route	Self-supply
	Direct supply over private wire
Becoming a supplier	Full Licence
	Licence-Lite
	White Label
Power Purchase Agreement (PPA)	Sleeving/ Peer-to-Peer
	Synthetic PPA
	Standard PPA

1.1 Self-Supply

SUMMARY

A self-supply route to market is where the export from a CHP is used to offset the generator's own consumption on the same site.

As the cost of importing power tend to be larger than the price received for exporting power, this can be an attractive option from a commercial perspective, although the economics of building an on-site power station needs to be assessed on a site by site basis. Where the export is larger than the on-site consumption, the generator will spill onto the distribution network and a PPA will be required with a supplier to capture the value of any spill.

DESCRIPTION

Under this arrangement, the generator is not registered with a supplier offtaker, as instead the electrical output is used to offset the metered import at the site. This is important as in the majority of cases the cost of importing power for use at the site will be considerably larger than the potential achievable revenue for exporting the power under a PPA.

Where there is any excess power (power generated beyond the site's consumption) it will spill onto the distribution network. In this situation, the generator will need to register their export with a supplier and use a PPA for these volumes (or give power away).

The use of power on-site means that the generator / consumer avoids having to use the national transmission system and local distribution systems. This results in an effective price achieved for the electricity producedwhich is equivalent to the retail market price, and therefore a substantial premium to the wholesale price.

An important point to consider is whether the reduction in consumption at the site, or any export, will have any system impacts for the local DNO. For example, if the site is connected to a generation dominated part of the distribution network. Consideration will also need to be given to the metering arrangements at the site to make sure that it is possible to attribute power flows to the correct parties.

EXAMPLES OF SELF-SUPPLY

Self-supply is used by an increasing number of parties within GB. At the larger end of the scale this includes embedded CHP's and other generation assets within public sector campuses and industrial and commercial sites. These embedded generators display a significant range of scale, from relatively small generation assets used to meet a part of the site's demand to large generators that are able to export power in addition to meeting the site's needs. Common examples of sites with self-supply arrangements are large users such as hospitals or hotels, but at the smaller scale are often found in sites with high heat demands such as swimming pools. The uptake of photovoltaic (PV) panels by domestic users is also an example of self-supply where the electricity generated by the PV panels is used to offset demand with any excess exported to the distribution network.

RELEVANCE TO CHP

Generation from the CHP can be used on site rather than exported under a PPA. This should increase the value achieved for the generator as the value of the export can be assessed based on the site's import charges which are being offset.

In addition to this, the use of on-site generation avoids the charges associated with using the national transmission system and local distribution system, minimises network losses and avoids the costs of renewable levies and the capacity market. However, under a self-supply arrangement, the generator will remain liable for the Climate Change Levy (CCL) unless an exemption applies. The default position is that self-supply is not excluded from the main rates of CCL. The definition of self-supply used by HM Revenue and Customs is as follows:

"*If you are a gas or electricity utility or a producer of Liquefied petroleum gas (LPG) or other taxable commodities and consume for your own business purposes taxable commodities that you would otherwise* *supply on (for example, to heat and light administration buildings unconnected with your production activities) these are deemed to be self-supplies. You must account for the main rates of CCL on your self-supplies in addition to any CCL due on your supplies of taxable commodities to third party consumers."*[105]

There are a range of exemptions from the CCL set down in legislation which a heat network adopting or connecting to a CHP may be able to utilise. For example, a CHP station assessed and fully certified under the CHPQA programme[106] is eligible for favourable treatment under the CCL legislation. Full details of the exemptions are available from HM Revenues and Customs.

If the CHP's electricity production exceeds the sites usage then the additional power will be exported over the local grid. In this case, the generator will need to sign a PPA with an offtaker party to allow the generator to achieve additional revenues from the exported power in addition to the offset usage. Heat production can also exceed a site's usage e.g. there can be times when it is economic to generate power and reject unwanted heat to atmosphere. Alternatively, it may not be economic to operate CHP when the site has need for power because of the lack of a use for the heat; in this case the plant has spare capacity. In either of these situations, connection to a heat network presents an opportunity to generate additional revenue from CHP.

Regardless of whether the site exports power or not it will still need to retain a connection to the distribution network. This will allow the export of excess power if needed, but more importantly will ensure that supply is maintained when the CHP is unavailable.

Overall this represents an attractive option for CHPs embedded within consumption sites. However, exact utilisation will also depend on factors such as heat demand and the relative economics of the plant.

105 Excise Notice CCL1: a general guide to Climate Change Levy – Section 2.4.1
106 Combined Heat & Power Quality Assurance Programme

1.2 Private wire

SUMMARY

This arrangement allows a generator to supply power to a third party through a private wire and does not use the distribution network. This may be a supply to one or many premises. There will be a contractual relationship between the generator and the third party that specifies the price paid for the power. This type of arrangement has become increasingly commonplace as the generation export offsets the site import for the third party and the potential value of the generation can therefore be judged against the import costs of the third party.

The additional value generated under this type of arrangement will be split between the generator and the import site. The value of the energy sold takes into account the cost of installing and maintaining the private wire. If the generator spills any excess generation onto the distribution network, a PPA with a supplier will be required to capture this additional revenue.

A private wire arrangement means that customers are (typically) being supplied with electricity without a supply or distribution licence. There are a number of class exemptions that enable this and the CHP or relevant entity will need to ensure it is compliant with the exemption criteria.

Private networks or private wires are catch-all terms to describe small-scale electricity distribution networks owned and operated by private parties rather than local Distribution Network Operators (DNOs). Private networks come in many forms, such as airports, caravan parks, district energy schemes and industrial estates.

Private networks work in a similar way as the distribution network, by enabling generation to connect and contract directly with a consumer over the private wires. An end-consumer using this network can avoid numerous costs associated with flowing power across the public networks and will normally fix a price with the generator for the private power flows.

DESCRIPTION

Private networks are more properly called licence-exempt networks, and their operators Exempt Network Operators (ENOs). *The Electricity Act 1989*, amended by the *Utilities Act 2000*[107], allows parties who meet certain criteria to be exempt from having an electricity transmission or distribution licence. The Electricity Act (Class Exemptions from the Requirement for a Licence) Order 2001 sets out the distribution licence exemption limits which are set out in Chapter 6. It should be noted that there is no application process for class exemptions; the party must satisfy itself that its activities fall within the exemptions.

There is a growing preference among large industrial electricity consumers to combine local generation with private networks when planning new development projects, primarily driven by the strong economic case. Private networks enable behind-the-meter solutions which allow (probably) licence exempt suppliers and generators to realise savings associated with the avoided costs of not using the distribution and transmission networks and other supply on costs associated with low-carbon subsidy programmes.

Network cost avoidances are very location specific and can also be achieved through location choices on the public network. However, when combined with behind the meter generation, a private wire route can unlock greater opportunities for the end consumer to avoid policy and subsidy costs. In 2017-18 the key policy costs to end consumers are:

[107] *Utilities Act 2000*

- The Renewables Obligation ~1.8p/kWh
- Feed-in Tariffs ~0.55p/kWh
- Climate Change Levy ~0.55p/kWh (although some large users can achieve a 90% exemption)
- Contracts for Difference ~0.2p/kWh
- Capacity Market ~0.3p/kWh

This totals ~3.4p/kWh in 2017/18 and is equivalent to around 30% of a major end users bill. With these costs forecast to rise in the future, the economic case for end users to consider generation is increasing. Although generation is attractive, consumers may wish to engage with third parties to contract for the service for commercial reasons. There are likely to be opportunities for generators to create returns for the project without the need for subsidy if a price for electricity can be agreed at around 8.0p/kWh.

The benefit that can be achieved through a private wire approach is largely dependent on the cost of the private wire. If substantial infrastructure is required, this may make the private wire approach uneconomic.

The table below demonstrates the potential for additional revenue that can be earned based on an avoided import price of 10p/kWh, a capital investment in private wire of between £0.1m and £1m and a 5% discount provided to the end customers. It should be noted that costs relating to VAT and the Climate Change Levy (CCL) are also likely to be incurred, unless a threshold applies or a reduced level of VAT is applicable.

Figure 52: Potential revenue impact of a private wire agreement

	Low private wire capex	Medium private wire capex	High private wire capex
Import Price (p/kWh)	10.0	10.0	10.0
Import price after reduction for VAT and CCL (p/kWh)	7.9	7.9	7.9
Units exported from 1MW CHP at 70% load factor (kWh)	6,132,000	6,132,000	6,132,000
Avoided import tariff cost (£)	£481,975	£481,975	£481,975
Illustrative revenue for 1MW CHP in West Midlands area	£347,010	£347,010	£347,010
Private wire annualized cost	-£8,167	-£40,833	-£81,667
Retail discount for demand customer (5%)	-£24,099	-£24,099	-£24,099
Additional Revenue generated	£102,700	£70,034	£29,200
Percentage uplift in revenue	30%	20%	8%

CONTRACTUAL ARRANGEMENT

The process of establishing a private wire route to market is to identify a number of potential customers who are within a close enough proximity to make such a route to market worthwhile. The range will depend on the size of the customer(s) and how easily it would be to install a private wire. As a general guide, a 400m radius would be a good starting point to identify applicable customers.

It is also important at this stage to review the class exemptions that may be relied upon to enable the sale of power over the private wire agreement. Given the complexity of these class exemptions and the risk associated with not interpreting these correctly, it is recommended that expert advice is obtained before resource is used approaching potential customers.

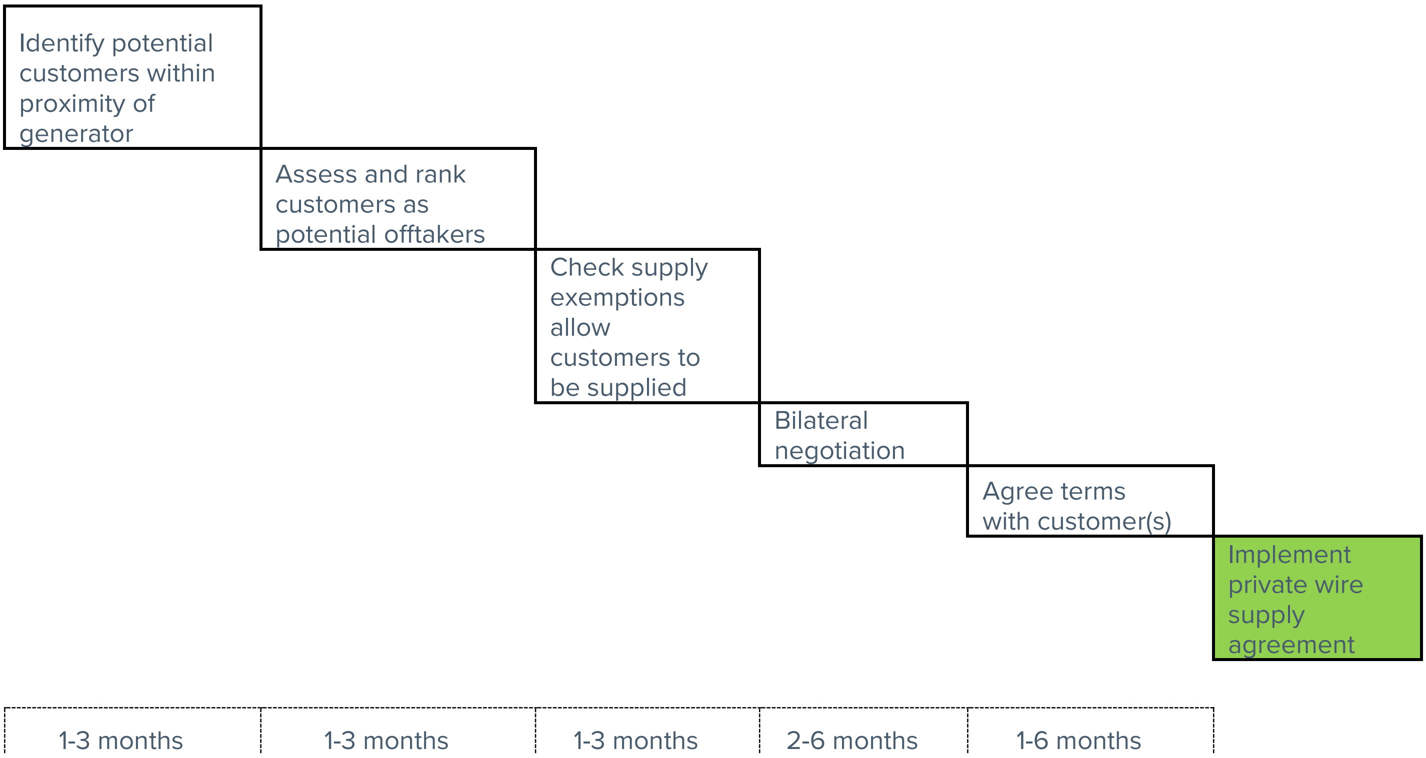
Once customers have been identified, a negotiation can commence. This may require education of the customer of the workings and benefits as many customers are unfamiliar with this type of arrangement which may form a cultural barrier. In addition, where there are a number of customers, the generator needs to assess each one to determine how well the demand profile matches the expected generation and whether the demand is expected to persist in the long term and the resultant risk if the site closed down.

Once an agreement is established in principle, the negotiations are based around the savings and avoided costs associated with not using the public network. Savings on this can then be shared with a generator, typically at a level that will see significant savings for the end consumer and be at a level for the generator to invest against. A generator will also compare the potential private wire fixed price to any potential subsidy mechanism it has access to on the public networks.

Consideration to how supply is maintained for customers in instances where the generation asset cannot meet demand, for example where the plant is down for maintenance, is also key. Most existing customers have pre-existing supply arrangements (although these may need to be reviewed) although this may be further complicated if the customer has their own back-up generator.

The diagram below shows the processes undertaken when agreeing a private wire agreement for the export from an embedded generator. It should be noted that the timescales provide an indicative range, but the actual time will vary for each site.

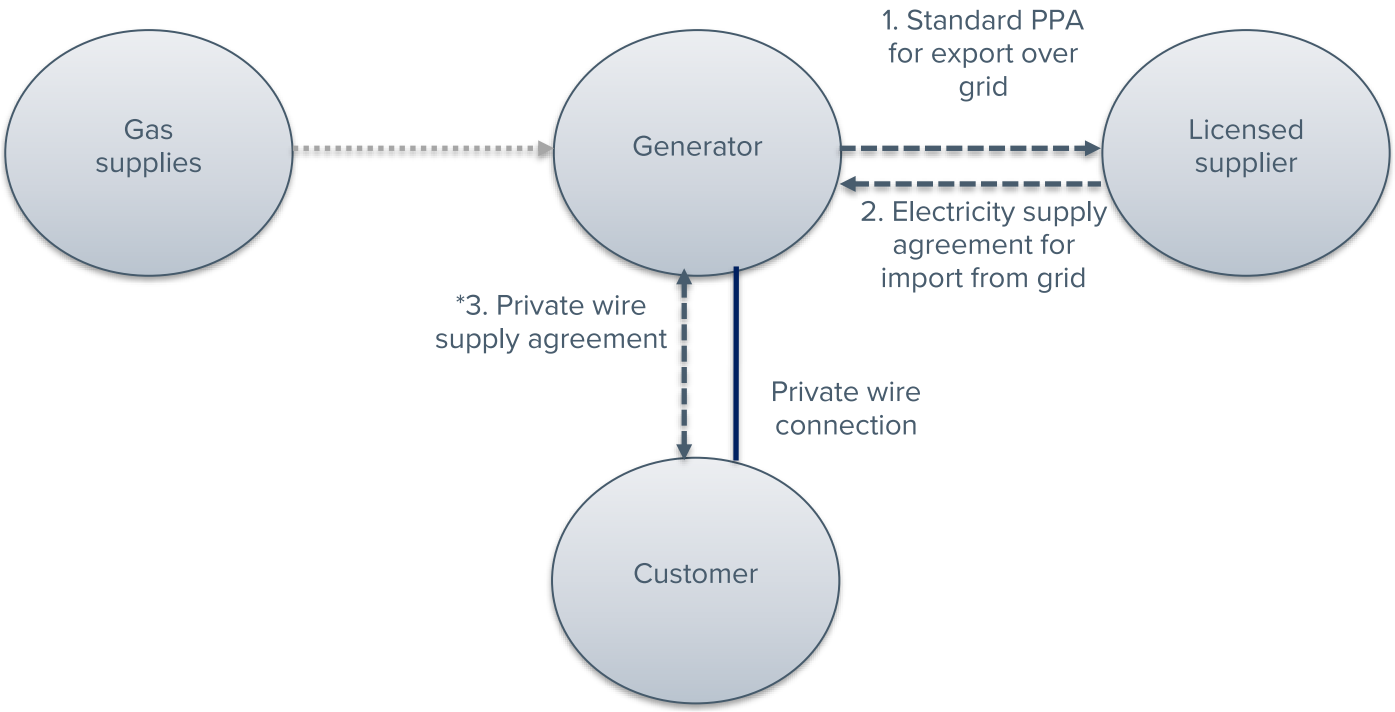
Figure 53: Process and timescales for private wire



Additional agreements may be required depending on the scale of the generator and customer in question. Some generators may see their full volumes transferred across a private wire with no need for external agreements. Others may still need a connection and meter point with the public network to ensure excess volumes are sold, perhaps under a standard PPA. End users will typically still have a supply contract on the public network in the likelihood that additional volumes will be needed if a generator is undergoing maintenance or shutdown.

The diagram below shows an example of the contractual arrangements between the key market participants under a private wire agreement (with a set-up similar to that illustrated in Figure 10 Option 2):

Figure 54: Contractual arrangements between parties



RELEVANCE TO CHP

CHP projects are seen as a good partner in a private wire agreement due to their baseload generation patterns. Like sleeving, private wire can provide potential synergies with heat offtake as existing energy supply relationships facilitate discussions about supply of a different type of energy. CHP generators can source joint heat and power offtakers or consumers through this process. The use of private wire arrangements for CHP projects is relatively widespread.

Although historically, CHP utilising private wire, has benefited from the regulatory regime for embedded plant, Ofgem have expressed concern that the current arrangements may not be cost reflective. Ofgem are considering changes to the level of embedded benefits and have identified behind the meter generation as a priority issue. This is because behind the meter generation such as private wire leads to third party costs (e.g. costs of providing the public network and subsidies for renewables) being recovered across fewer customers who therefore incur higher charges. This creates a greater incentive for demand customers to seek private wire and self-supply arrangements.

The concern that Ofgem have highlighted means that a risk exists that changes to the regulatory regime are brought forward that will impact on private wire arrangements. This could mean that CHP generators could face additional costs in the future that it may not be able to recover from customers connected via the private wire. It is recommended that expert advice is sought in this area to protect against industry change and provision built into the private wire contractual arrangements to ensure the project has some protection against any regulatory changes that may emerge.

1.3 Fully licensed supply

SUMMARY

A fully licensed supply route to market is where an organisation acquires a full supply licence and is responsible for all aspects of compliance with the licence, these are described in more detail later in this section. A fully licensed supplier may undertake all aspects of providing the supply to the end customer or decide to outsource some aspects for commercial reasons. However, the licensed supplier would retain the ultimate responsibility of compliance with industry codes and the customer facing obligations set out in the licence.

DESCRIPTION

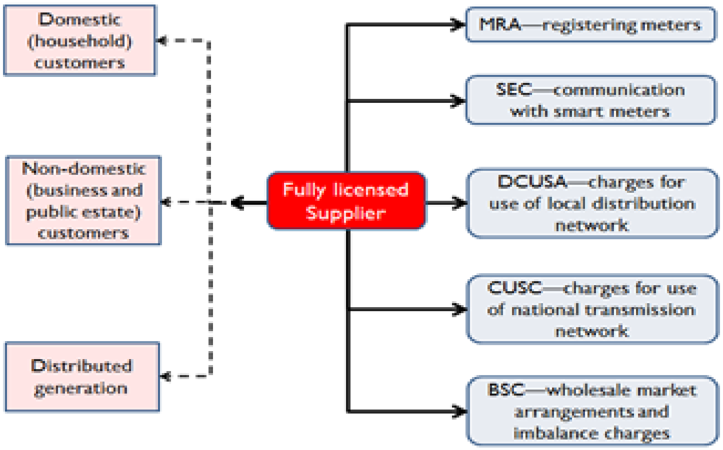
Fully licensed supply is the 'typical' route to market for parties seeking to gain electricity customers. A fully licensed supplier needs to comply with the conditions that are set out within their electricity supply licence. These licence obligations can be both onerous and costly to comply with and require a significant investment in infrastructure and staff. However, this route to market does allow the party the greatest value retention by the supplier and the largest flexibility in its offering.

A consideration under this option (and indeed to a lesser extent, the Licence Lite option) is whether the party wishes to enter the market as a non-domestic (e.g. business) only supplier or domestic (household) supplier, and in what order or, indeed, to limit activity to trading in the wholesale market (see below). Non-domestic supply is less onerous in terms of system and resource requirements due to the smaller number of customers and less prescriptive customer facing rules and consequently tends to have lower set-up and ongoing costs. However, the margins that can be achieved for smaller domestic customers tend to be greater than in the large commercial market. In many cases, a new supplier may aim at the larger commercial market initially and progress to domestic once it is more established. Some heat network sponsors (e.g. Local Authorities) may have a substantial non-domestic electricity consumption portfolio and there may be synergies with setting up as a licensed supplier to supply these sites.

CONTRACTURAL ARRANGEMENT

The diagram below shows the contractual relationship between the fully licensed supplier and customers, embedded generation and the industry codes it is required to sign up to.

Figure 55: Full supply licence [108]



EXAMPLES OF FULLY LICENSED SUPPLY

Fully licensed supply has long been the traditional route taken by parties seeking to enter the supply market. This has partly been due to the lack of alternative options, Licence Lite being yet to be proven and White Label having limited utility, and partly due to the level of flexibility and value retention it offers. Due to this a number of local authority backed and 'social' suppliers enter the market in this manner.

To date the local authority backed suppliers that have entered the market have been domestic focused, primarily due to the social aims they want to deliver, but some are also offering non-domestic contracts. However, the reliable, flexible output from a CHP plant makes it better suited for non-domestic supply as it is able to more closely track the typical consumption profile of non-domestic customers and so minimise the imbalance costs faced.

Bristol Energy

Bristol Energy was established by Bristol City Council with a social focus on Bristol and the South West. It entered the market in February 2016, initially with just a domestic offering, but now also supplies the non-domestic market.

Bristol Energy markets itself as trying to "make a meaningful difference to the energy sector". The supplier makes partnerships with local charities, including those helping the homeless, elderly and vulnerable.

It is currently one of two suppliers to voluntarily participate in the Warm Home Discount scheme for winter 2016-17, alongside Our Power. Bristol Energy offers a range of tariffs, including a green tariff and a tariff specifically for Bristol residents.

Robin Hood Energy

Robin Hood Energy was the first fully licensed municipal supplier, launched by Nottingham City Council in September 2015. The supplier offers domestic gas and electricity, and is looking to offer non-domestic supply "in the near future".

As a not-for-profit company, Robin Hood looks to provide low cost energy, highlighting on its website that it is different from other energy companies with no private shareholders or bonuses paid to directors. The supplier does not apply exit fees to its tariffs.

[108] MRA = master registration agreement; SEC = smart energy code; DCUSA = distribution connection and use of system agreement;CUSC= connection and use of system code; BSC = balancing and settlement code

ADOPTING A FULLY LICENSED SUPPLY

Becoming a fully licensed supplier is a relatively straight forward process. To acquire a supply licence the party needs to complete a straightforward form and pay a small (£450) fee to Ofgem for the administration.

However, once acquired, the supply licence places a number of onerous obligations on the supplier. These can be broken down into three broad headings: licence compliance, industry code accession, and government programme obligations. All three involve, to varying degrees, initial expenditure as well as ongoing resource.

The electricity licence requires the supplier to accede to the complex industry codes that set out responsibilities and requirements necessary to ensure the effective operation of the electricity system and functioning of the market. These codes are set out below:

- Balancing Settlement Code (BSC)—ensures the system is balanced (e.g. supply and demand is continually met) and that electricity volumes entering and leaving the transmission system are correctly apportioned to the right party. Parties are exposed to imbalance charges for un-contracted trades. Code administrator is Elexon.
- Connection and Use of System Code (CUSC)—sets out the commercial arrangements for parties connecting to or using the transmission system. Code administrator is National Grid.
- Distribution Code—details the technical parameters and considerations relating to connection to, and use of, distribution networks. Code administrator is the Energy Networks Association.
- Distribution Connection and Use of System Agreement (DCUSA)—sets out the commercial arrangements for parties connecting to or using the distribution network. Code administrator is Electralink.
- Grid Code—covers all material technical aspects relating to connections to the transmission system as well as its operation and use, and also specifies data that parties are obliged to provide to National Grid for use in the planning and operation of the transmission system. Code administrator is National Grid.
- Master Registration Agreement (MRA)—enables the change of supplier process to function by identifying suppliers responsible for customer meters. Code administrator is the MRA Service Company.
- Smart Energy Code—covers aspects of how smart meter data is communicated across the industry and charges associated with the 'DataCommsCo' for providing the communication infrastructure. Code administrator is GemServe.

A large element of cost associated with establishing a fully licensed supply business is the system and expert resource requirements needed to accede to these codes (particularly the BSC and MRA) and on-going compliance under them.

The obligations contained within the licence are more onerous where supply is made to households (but still significant for supply to businesses, especially smaller ones[109]) and ensure consumers receive adequate customer service levels.

The key obligations are focused around: gaining customers; supplying customers; required services; and losing customers. Currently the rules are highly prescriptive (particularly for domestic customers) and so limit

[109] The gas and electricity supply licences include additional protections for "microbusinesses". These are defined as a company (not site) that meets at least one of the following criteria: annual electricity demand less than 100,000kWh; annual gas demand less than 293,000kWh; fewer than 10 employees (or their full-time equivalent); and an annual turnover or annual balance sheet total not exceeding €2mn.

the innovation that suppliers can undertake. This is moving to a more principles based approach which should allow greater flexibility, but also potentially increases the risk faced.

FINANCIALS

This section contains a high-level overview of the likely upfront and operational costs that will be incurred under a fully licensed supply arrangement. It should be noted, that these values are purely indicative and will vary considerably depending on the circumstances and the ambitions of the owner of the fully licensed supplier. It is therefore recommended that a potential developer undertakes their own assessment of the costs they are likely to incur in setting up this type of operation.

Most new entrants decide to procure a “supplier in a box” market entry option to enter as a fully licensed supplier. This is where a specialist utility IT systems vendor gains an electricity supply licence and accedes to a number of the core industry codes. This prequalified licensed company is then sold onto the new entrant and from this point forward the company assets are transferred to the new entrant and the new company can go through Controlled Market Entry (CME). This forms the final stage of accreditation and demonstrates to market administrators that the new entrant understands how to register meters and manage associated data flows. This process results in the new entrant avoiding the majority of the accession process itself.

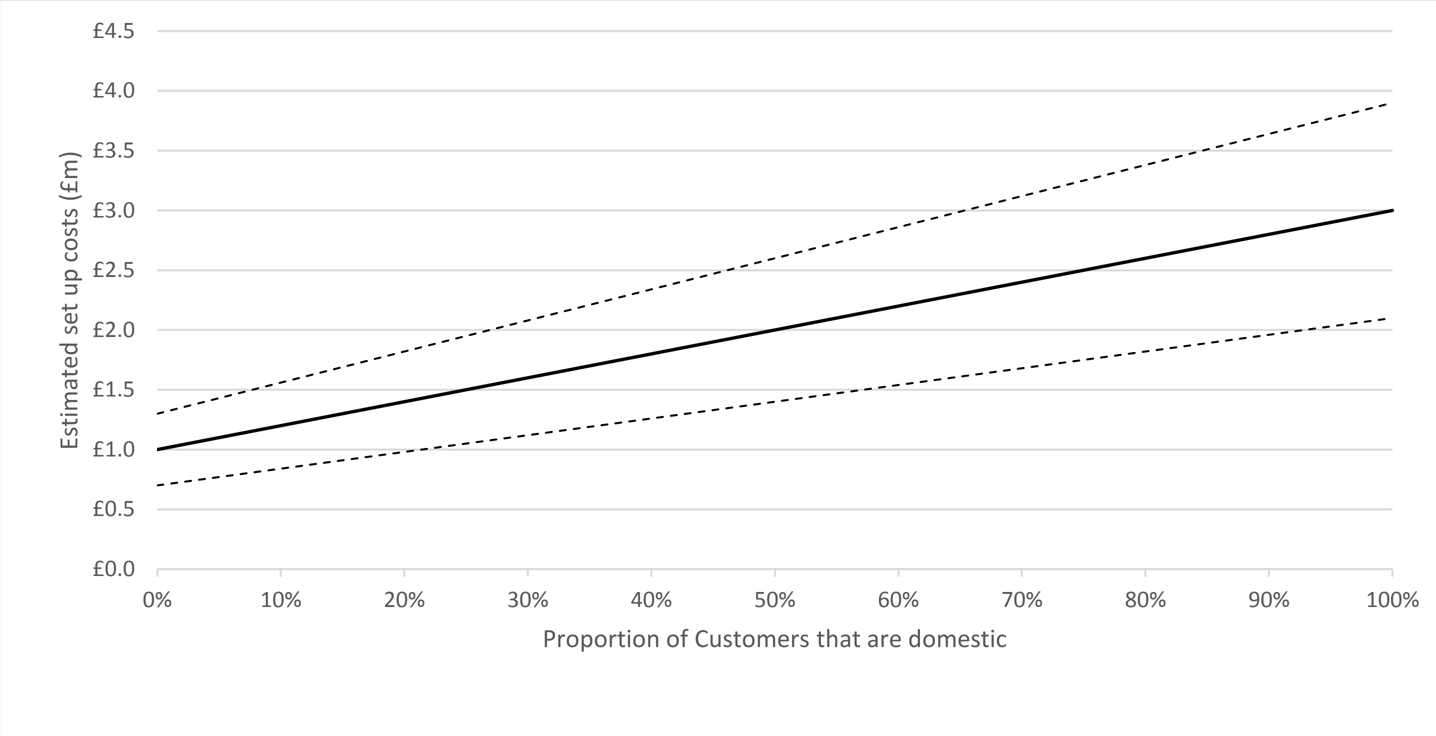
a) Upfront Costs

The main upfront investment costs are: procuring the prequalified licence and necessary systems; purchasing a CRM system suitable to the target customers; and accreditation and credit requirements for the industry codes. In addition to this, sunk costs from the project team and legal and consultancy support will also need to be considered. The set-up costs will also include the need for ‘typical’ business processes such as office space, telephony, insurance and the recruitment of permanent staff to run the business.

Overall, the investment costs to establish fully licensed supply are likely to range between £1,000,000 and £3,000,000 depending on ambition and target customer base. Set-up costs are a function of the necessary IT required, staffing resource, company overheads (e.g. office space, typical business expenditure, telephony, insurance etc.) and the time taken to complete adequate business and financial planning and to establish the legal entity undertaking the activity. These costs are effectively sunk and the supply business must generate sufficient margins in the future to recover this initial outlay.

The set-up cost estimates cover a wide range of costs as this is representative of the set-up options which allows many of the business elements to be outsourced or developed in house. The mix of customers is also an important consideration and the graph below provides an indication of how the set-up costs are likely to vary with the relative proportion of domestic to non-domestic customers that the new supplier plans to target for supply business model.

Figure 56: Indicative set-up costs (£m) for full licence against proportion of domestic/ non-domestic customers



Note: These are purely illustrative and do not consider the additional cashflow requirements for credit and collateral and to operate the business until it breaks even. Supply to non-domestic customers only is likely to be less costly due to the reduced regulatory customer facing obligations. The typical cost to serve a domestic customer is in the region of £21/MWh and £6/MWh to serve a non-domestic customer.[110]

b) Operating Costs

While the potential set-up costs needed to establish a fully licensed supplier are high, staffing and working capital requirements increase rapidly with customer growth and can quickly eclipse these costs. Working capital includes the requirement to lodge credit cover with different counterparties either for trading purposes or with industry agents where the requirements are set down in the industry codes. The supplier will need to ensure sufficient credit is lodged to ensure compliance with the industry codes. There is also likely to be a mismatch between the supplier receiving the money from customers and paying out to counterparties and this risk needs to be managed.

It is difficult to provide an estimate of these costs as they will vary significantly according to the supply route taken by the supplier, including the customer type, volumes supplied, and the level of outsourcing. However, an illustrative range would be £500,000 to £3,000,000 per annum, with the higher end representing sales to domestic customers with a rapidly growing customer base.

FULLY LICENSED APPROACH FOR GENERATION ONLY

To set up a fully licensed supply business with the sole aim of trading the output of a portfolio of customers on the wholesale market requires slightly lower upfront costs than a fully licensed supplier with demand

[110] Data sourced from an assessment of the Energy Company Consolidated Segmental Statements: https://www.ofgem.gov.uk/publications-and-updates/energy-companies-consolidated-segmental-statements-css

customers. An illustrative range of set up costs is £250k to £400k covering pre-accredited licence and industry flow systems, accreditation to industry codes and legal and consultancy support.

Ongoing costs will largely consist of the costs of running a trading desk and maintaining credit with a range of counterparties. The cost will vary with the number of traders and the amount of trading activity undertaken. An illustrative cost would be £250k to £350k per annum based on a desk comprising of three traders and would cover salaries, overheads, transaction fees, exchange membership fees and credit cover requirements.

RELEVANCE TO CHP

Fully licensed supply has the highest sunk and ongoing costs of any supply option. This is due to the high level of obligations that a fully licensed supplier is required to meet. Due to this fully licensed supply is deemed beneficial primarily for larger projects (100MW+) or developers with a large portfolio as they are spatially diverse and have the capacity to ensure this balancing risk is spread evenly and hence minimised. Where existing local authorities have adopted a fully licensed supply, this is primarily to meet their internal objectives of either securing low carbon supplies or affordable electricity for either their own sites or local communities, particularly for vulnerable or fuel poor customers. While this route enables full control over the value achieved for the electricity generated from a power station, a single plant with a relatively small generation capacity would be unlikely to benefit from this route to market.

1.4 Licence Lite

SUMMARY

Under a Licence Lite supply arrangement an organisation can become an electricity supplier without obtaining a full supply licence that requires it to comply with all of the central industry codes. Instead, the Licence Lite supplier will partner with a fully licensed supplier who will provide the additional services required under the supply licence. This approach allows an entity to become a licensed retailer of electricity without the investment in costly infrastructure. This approach was developed to encourage the emergence of smaller scale local electricity suppliers as the conventional approach was deemed too costly.

DESCRIPTION

The Licence Lite supply licence was introduced by Ofgem in March 2009 following the *Energy White Paper 2007*[111], in which government raised concerns that market entry procedures were too costly and complex for companies looking to establish themselves as a small supplier. The Licence Lite approach avoids this by enabling a partnership to be formed between the Licence Lite supplier (termed the junior supplier) and the fully licensed supplier (termed the senior supplier), where the activities associated with the industry codes are undertaken by the senior supplier.

Although the senior supplier achieves compliance on behalf of the junior supplier, charges associated with imbalance, paying for networks, and some metering activity will be passed through to the junior supplier. This arrangement ensures market arrangements are kept 'whole' and the Licence Lite supplier's activity can still be accommodated within the central arrangements. The contract between the two suppliers, known as the Supplier Services Agreement (SSA), will need to be presented to Ofgem before it can grant a Licence Lite licence. This is so the regulator can be satisfied that the arrangements work in the interest of consumers and the wider market.

The Licence Lite supply arrangement can be considered closer to a full licence approach than a White Label approach. Unlike the White Label approach, there is still a requirement to have a supply licence, albeit a cut down, Licence Lite version. The Licence Lite supplier has the direct contractual relationship with the customer and is directly responsible for meeting its own licence obligations related to customer service and participating in government schemes (e.g. the Renewables Obligation, small scale Feed-in Tariffs, CfDs, Capacity Market and roll out of smart meters), something that is not possible under White Label agreement. However, it does not incur the set-up costs of a full supply licence as it forgoes the need to invest in some of the IT required to interface directly with central market processes. These interfaces enable the senior supplier to exchange data with other suppliers, their agents and central industry processes and allows for the flow of data to enable the allocation of customers to suppliers and suppliers to be billed for these customers. The IT systems that are required for this process enable the supplier to transfer the data items set out in the industry codes within the timescales required for settlement purposes or in response to certain trigger items. All data transferred between parties via the national systems must use the data protocols set out in settlement codes.

This allows the Licence Lite supplier to set their own tariff structure, level of tariffs and the contract terms. The Licence Lite supplier is also able to determine its own strategy for the procurement of wholesale power. This includes purchasing directly from the wholesale market or through a PPA with an embedded generator.

In practice the Licence Lite supplier's meters (customer and embedded generation) are registered in the central industry systems as the senior supplier's sites with an identifier that flags them as being under contract with the Licence Lite supplier. Therefore the Licence Lite agreement will require information to be transferred between the junior and senior supplier in a format that will enable the senior supplier to interact with central

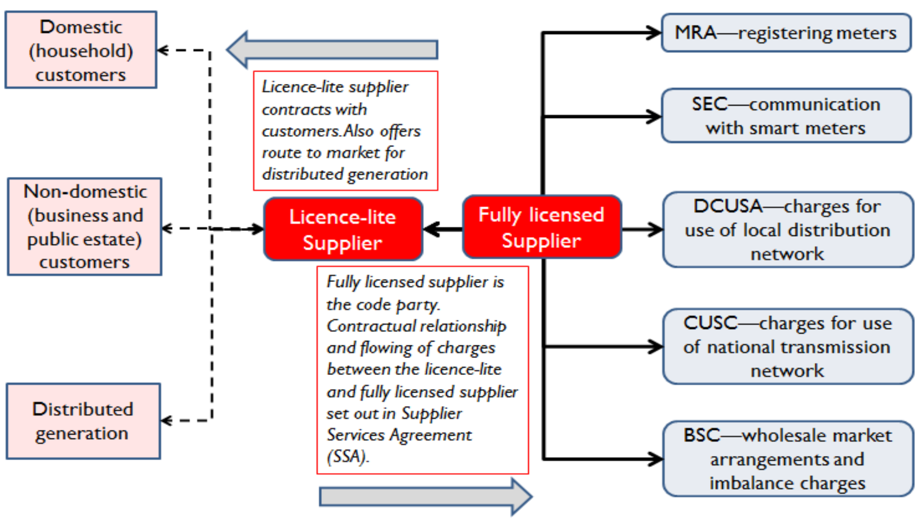
[111] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/243268/7124.pdf

systems. This will require the junior supplier to install IT systems that are able to interface with those systems of the senior supplier and provide the required information in an appropriate format and timely manner.

Under the Licence Lite arrangement there is a degree of flexibility for the junior supplier to agree with the senior supplier how the services are split between the two parties. The junior supplier may want to undertake the minimum services possible or it may decide to provide more of the supply services itself to reduce the cost of the arrangement. This approach may be particularly relevant where the Licence Lite supplier already has infrastructure in place and is able to provide these services relatively cheaply (for example the Licence Lite supplier may already own a call centre which can be used to handle customer queries).

The diagram below shows how a Licence Lite supplier interacts with industry parties:

Figure 57: Licence lite label supply



EXAMPLES OF LICENCE LITE SUPPLY

At time of publication, no organisations have adopted Licence Lite. However, Greater London Authority (GLA) has considered the option for several years and confirmed on 25 July 2016 that it would seek to become a Licence Lite supplier[112]. This announcement was followed two days later by a formal application for a non-domestic electricity supply licence. While no further information has been forthcoming in regards to the progress of the GLA, it is expected to go live in 2017.

The GLA plans to buy clean electricity from a generator panel including London boroughs, social housing providers, and other embedded generators. This is primarily a vehicle to take local generation to the customer and reduce the need to call upon the fully licensed supplier to provide wholesale products—a key design consideration is to match local generation to forecast demand as closely as possible. The GLA may look to supply other business customers and originally considered retail to domestic customers.

It should be noted that as this is still an emerging business model, there is no clear indication of the appetite for fully licensed suppliers to offer the necessary services to a Licence Lite supplier, nor how the more complex domestic arrangements would work in practice.

In many ways, the Licence Lite approach mimics licensing arrangements in the gas market where there is a separate gas supply licence (which sets out expected behaviours when interacting with customers) and gas

[112] https://www.london.gov.uk/press-releases/mayoral/mayor-plans-to-power-tube-with-clean-electricity

shipper licence (which determines the need to sign up to the industry code that ascribes roles and responsibilities related to paying for transporting gas across the networks and paying imbalance).

ADOPTING A LICENCE LITE SUPPLY

At the core of the Licence Lite option is the ability for a supplier to avoid the need to itself comply with the complex industry codes but still operate within the licence framework that all other suppliers operate.

The holder of a Licence Lite will be bound by the remainder of the licence that, at a high-level, determines the expected behaviours when interacting with consumers. This constitutes the primary regulatory requirements, which entails having sufficient resource (IT systems and personnel) to manage customer interactions across the "customer journey" from sales / marketing, through to account handling (including billing, complaint handling and provision of specific services to vulnerable customers), information provision, and closing of accounts where a customer leaves. In October 2014, the regulator Ofgem clarified that the Licence Lite supplier is also responsible for meeting the government's social and environmental schemes for its customers. Therefore, the Licence Lite supplier would have a Renewables Obligation, need to participate in the reconciliation mechanism for small scale feed-in tariffs (ssFiTs) scheme for small scale renewable technologies and pay supplier obligations for the new contract for differences (CfDs) and capacity market.

The licence application process is relatively straight forward. The applicant must apply to become an electricity supplier (if they are not already licensed) and seek a "Licence Lite direction". The latter sets out that the applicant is seeking to become a Licence Lite supplier and therefore will not comply with the licence requirement that mandates the licensee to accede to the core industry codes.

A key requirement for the applicant is to provide supporting documentation that includes a Supplier Services Agreement (SSA). This is the contract that determines how a fully licensed "senior" supplier will undertake industry code compliance for the four core codes[113] the Licence Lite "junior" supplier does not sign-up to.

The SSA specifies how the senior supplier will achieve industry code compliance for the junior supplier. This must be in a form that satisfies Ofgem that market arrangements remain "whole" and that the issuance of a junior licence does not confer a competitive advantage to any party or create a two-tier market.

Supplier Services Agreement

An SSA describes the contractual relationship between the Licence Lite and fully licensed supplier. It sets out how industry code compliance is achieved by the senior supplier on the junior supplier's behalf.

Required terms are likely to include:

- nature of senior/ junior relationship
- contract duration
- both parties' responsibilities to ensure code compliance
- explicit agreement from the senior supplier it will ensure code compliance on behalf of the junior supplier
- dispute resolution processes
- arrangements for continuation of supply to customers where the SSA is terminated
- data privacy and exchange arrangements
- processes for identifying the junior supplier's meters (customers)
- payment arrangements;
- day-to-day operation service specification

Where a Licence Lite supplier is relying on embedded generation to meet their demand, there is also the need for "top-up, spill and standby" arrangements to be agreed with a third party, commonly referred to as the "Netting Off Agreement" (NOA) probably, but not necessarily, with the senior supplier. As local generation output will never exactly meet customer demand, this separate contract provides a means to cover times where local generation output is lower than customer demand (i.e. top-up), instances where generation output exceeds customer demand (i.e. spill), and for periods of planned generation outages (i.e. standby). The cost of providing the top up and spill will be based on market rates, normally in the short-term wholesale market which gives sufficient granularity of

[113] Balancing and Settlement Code (BSC), Master Registration Agreement (MRA), Distribution, Connection and Use of System Agreement (DCUSA), Connection and Use of System Code (CUSC)

price to enable the anticipated half-hourly imbalance to be procured.
The timetable for settlement of these costs will be set out in the NOA.

FINANCIALS

This section contains a high-level overview of the likely upfront and operational costs that will be incurred under a licence-lite supply arrangement. It should be noted, that these values are purely indicative and will vary considerably depending on the circumstances and the ambitions of the owner of the licence-lite supplier. It is therefore recommended that a potential developer undertakes their own assessment of the costs they are likely to incur in setting up this type of operation.

a) Upfront Costs

The costs of setting up a Licence Lite operation are significant, as unlike White Label supply the Licence Lite supplier is responsible for undertaking all the customer facing activities. This therefore may require a substantial investment in Customer Relations Management (CRM) systems and staff. However, as central electricity code compliance is achieved via the SSA the “junior” supplier avoids the expense of procuring an IT system necessary to discharge industry code obligations, which is typically one of the largest single cost items of establishing a fully licensed supplier.

As a licence holder it must ensure it has an adequate CRM and associated billing system to comply with its licence and can interface with the systems of the senior supplier. An estimated cost for this would range between £50,000 to £300,000 depending on ambition. The lower end represents where supply is made to a small number of non-domestic customers and the higher end for a large number (thousands) of domestic consumers.

Arguably more important are the sunk costs that would be faced establishing a Licence Lite supplier. These are likely to include significant legal and consultancy support costs to aid the negotiation of the SSA and NOA and represent the unproven nature of the option. These could reach up to £500,000 if the contract is particularly complex or ‘non-standard’ although over time it is likely that this type of agreement will become more standardised with much lower costs to establish.

b) Operating Costs

Operating costs from Licence Lite supply are significant. This is because the requirement to comply with the supply licence and the broader responsibilities taken on requires a substantial staff requirement on the supplier. In addition, the Licence Lite supplier will look to have in place wholesale contracts (with local generators and/ or the wider wholesale market, possibly with the Senior Supplier) to ensure it can meet forecast customer demand and avoid imbalance. Again, these costs will vary based on the size of the customer base and type of consumers targeted. Licence lite suppliers will also need to factor in the payments to the licensed supplier under the SSA. An approximate range for the ongoing operating costs faced at launch is between £250,000 and £450,000 per annum.

The requirement to provide working capital under a Licence Lite business model is not as extensive as for a fully licensed supplier. The senior supplier will be required to lodge the credit requirements for industry codes as they are the signatory. The credit costs associated with the Licence Lite arrangement will be between the senior supplier and the Licence Lite supplier. The Licence Lite agreement will specify the amount of credit required and how this can be met, and this will form a negotiating point when entering into the agreement. However, the Licence Lite supplier will also need to lodge credit with different counterparties for trading purposes to allow them to operate within the wholesale market. As with a fully licensed supplier there will be a mismatch between the timings of incoming cash from customers and cash outflows to settle industry bills and these will need to be carefully managed.

RELEVANCE TO CHP

The Licence Lite approach was initially designed to help encourage smaller generators become active in the supply market by reducing the barriers to entry.

It could be thought of as an intermediate option between White Labelling and fully licensed supply, but tends more towards full licence. It offers lower entry costs than fully licensed supply due to industry code compliance being handled by the partner, which also simplifies setup and operations. However, Licence Lite is only cheaper to establish relative to fully licensed supply and operating costs may not be significantly lower, although the magnitude of saving will depend on the business model adopted. It will still be a major undertaking requiring specialist skills. Although set-up costs are lower, a portion of its revenue (albeit a small one) would have to be passed to its fully-licensed partner.

The main potential problems for Licence Lite surround the dependence on a senior partner with a full supply licence. It is possible that the partner may not guarantee reasonable terms, may not deliver under contract, or a willing partner may not even be found. Another risk is the long term viability of this model, given the reliance on the contract with senior supplier. In the event of contract expiry, whether at the end of the contract period, the use of a break-clause or non-delivery, then the Licence Lite supplier's customers would revert to the fully licensed supplier.

For CHP generators, Licence Lite offers the opportunity to access the retail market at a lower upfront investment cost than fully licensed supply. Importantly (and a key difference to White Label) is it would retain greater control over customer pricing, marketing, and product type, and have a direct role in wholesale contracting arrangements.

1.5 White Label supply

SUMMARY

A White Label partnership route to market involves contracting with an existing licensed supplier to use their supply infrastructure and risk management systems to create a new brand for the supply of electricity without the need to invest in the infrastructure necessary to become a full supplier or Licence Lite supplier. To enable this option a new company is formed with a unique brand that can offer tailored and branded energy tariffs to customers, but the management of the customers is undertaken by the fully licensed supplier.

DESCRIPTION

A fully licensed supplier needs to comply with the conditions that are set out within their electricity supply licence. These licence obligations can be both onerous and costly to comply with and require a significant investment in infrastructure and staff. The White Label supply approach avoids this by enabling a partnership to be formed between the White Label supplier and the fully licensed supplier, where the activities associated with supply licence compliance are undertaken by the licensed supplier. The arrangement typically seeks to offer a local or specialised White Label tariff. The end customer price is largely driven by the partner fully licensed supplier's own costs. The White Label may offer local generation output and reduced marketing and sales costs as a means to reduce consumer prices.

As the White Label supplier is not a licensed supplier, it is not required to hold a supply licence and instead has a contractual arrangement with a licensed supplier. This contract will enable the White Label supplier to sell contracts to end customers in its own brand. Once a sale is agreed, the new customer is registered to the licensed supplier who undertakes all the activities associated with supplying the customer with electricity.

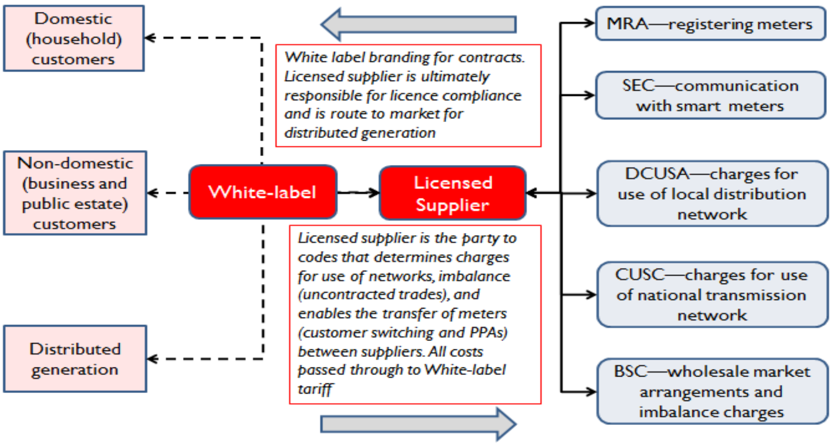
Under a White Label agreement there is some flexibility regarding which services are provided by each party to the agreement. Where a White Label supplier already has the infrastructure set up to provide some elements of the supply business, they may wish to provide these services themselves to reduce the cost to the licensed supplier and secure a larger margin. An example of this is where a White Label supply business already has a call centre and decides to adapt it to manage customer enquiries themselves. The degree to which these services are split between the White Label supplier and the licensed supplier will form part of the negotiation of the partnership agreement.

Some arrangements will provide payments from the licensed supplier partner to the White Label for each customer gained. New models are emerging that look to ensure the White Label tariff price remains fairly priced (i.e. by reference to competitor tariffs) and for monthly and/ or retention payments made to the White Label suppliers.

CONTRACTUAL ARRANGEMENTS

The figure below shows how the contractual arrangement between the White Label supplier and the licensed supplier tends to work in practice.

Figure 58: White label supply



EXAMPLES OF WHITE LABEL SUPPLY

White label supply arrangements can be beneficial for both parties. From a fully licensed supplier's perspective it establishes a route to market that enables them to capture market share by utilising the brand established by a third party. This is effectively a cheap way for the licensed supplier to acquire new customers. Good examples of this are for established brands like Marks and Spencer or Sainsbury who have direct access to their end customers and have an established brand that their customers trust. The licensed supplier therefore acquires market share on the back of the existing brand. In return for winning the customers, the White Label supplier typically receives a commission from the fully licensed supplier that covers their cost of acquisition plus a margin. The level of the commission will depend on the contractual relationship but will vary based on the value associated with the brand and the expected volume of customers that will be signed up.

OVO Communities

OVO Energy launched OVO Communities in 2014. This is a new technology platform that allows local community groups to sell energy to local residents, generate their own power and invest in energy efficiency, without the need for big investments in energy systems, technology and infrastructure.

OVO has invested heavily in scalable systems that will give energy companies all the tools they need to run a utility business including customer service, billing, trading, and power generation. The company also offer next generation smart metering, power purchasing and energy efficiency installations as part of its new platform.

From a potential White Label supplier perspective, a White Label agreement allows a route to market without investing in the infrastructure required to become a full supplier. It may be that the White Label supplier is just trying to leverage value from an existing brand or it may want to establish its own brand and niche tariffs but is unable or unwilling to commit to becoming a full supplier.

Ebico

Ebico is a certified social enterprise, using surplus profits to support households in fuel poverty. It handles customer enquiries in-house and offers tariffs with no standing charge.

Ebico has been operating as a white label for around 15 years since February 2017 its licensed supply partner is exclusively Robin Hood Energy, which provides both energy and account management services. Ebico supplies energy to over 60,000 households.

This is the approach currently being adopted by several local authorities who are looking to establish local brands to their existing customer base.

Typically, White Label supply companies to date have focussed on the domestic market. Although there is no restriction that prevents White Label suppliers from entering the non-domestic market, this is not a business model that has emerged to date.

ADOPTING A WHITE LABEL SUPPLY

The provision of a White Label service is discretionary and as such there are no standardised commercial agreements in the market. The contractual relationship will therefore be bespoke and require terms and conditions to be negotiated. Typically, the following areas will need to be covered:

- The value and payment terms for the commission arrangements. This may include upfront fees levied by the supplier
- The services that are to be provided by each party under the agreement
- The potential for retention fees if a customer renews their contract when it expires
- Any constraints or restrictions on the practice of the White Label supplier or licensed supplier, including possible limitations on the tariff types that can be offered
- How dataflows are managed between the White Label and licensed supplier
- The fully licensed supplier offering the service will require to be indemnified from White Label activity that may cause it to breach licence conditions
- Generation assets owned or under contract with the White Label could form part of the arrangement
- Duration of the agreement and break clauses

It should be noted that entering into a White Label supply arrangement will involve risks for each party. The partnership agreement will therefore need to be assessed from both a commercial and legal perspective to determine the potential liabilities that may arise under the contract. Organisations, such as owners of CHPs or local authorities should assess these risks prior to and during negotiations for a White Label agreement and ensure the agreement contains measures to mitigate any risks that cannot be managed or are perceived to be excessive.

FINANCIALS

This section contains a high-level overview of the likely upfront and operational costs that will be incurred under a White Label supply arrangement. It should be noted, that these values are purely indicative and will vary considerably depending on the circumstances and the ambitions of the owner of the White Label supplier. It is therefore recommended that a potential developer of a White Label supply agreement undertakes their own assessment of the costs they are likely to incur in setting up this type of operation.

a) Upfront Costs

The primary upfront investment requirement for a White Label supply arrangement involves costs associated with negotiating and agreeing terms with the potential fully licensed supplier partners. The main parties involved in this negotiation will be: the senior management from the contracting parties, legal support to review the arrangements, and energy advisors to provide commercial support.

The upfront costs to negotiate and agree the White Label partnership agreement will vary from company to company. The time and cost can be reduced if the licensed supplier can provide an agreement that they have used elsewhere. The costs that an organisation can expect to incur from setting up a White Label supplier are likely to range from £50,000 to £80,000 depending on the complexity of the desired arrangements and the negotiation process.

There are no collateral requirements, although the fully licensed supplier may seek a commitment for the White Label to guarantee a number of customers during the life of the contract and/ or cover any costs associated with producing compliant marketing and sales materials.

b) Operating costs

Operational costs can be split into marketing costs which are required to establish the brand and attract customers and staff costs to support the sales and marketing activities and manage the contractual relationship with the licensed supplier. It should be noted that the licensed supplier has strict licence conditions that govern how sales and marketing activities are conducted. The White Label supply approach is not a means for the supplier to avoid these licence conditions and the licensed supplier will be liable for any breaches that the White Label supplier makes in this area. Consequently, the partnership agreement will specify what the White Label supplier can and cannot do and may require that the licensed supplier pre-approves all sales and marketing activity.

The level of marketing spend will depend on the budget and ambitions of the White Label supplier. Some licensed suppliers may request a minimum spend by the White Label supplier to increase the likelihood of the White Label supplier being a profitable partnership for the licensed supplier.

An illustrative operating cost for White Label (contract management and sales and marketing) of between £50,000 to £100,000 depending on ambition and contractual obligations.

RELEVANCE TO CHP

For CHP, a White Label approach offers the cheapest way to access the supply market. The competitive advantage that the CHP may be able to capture is to leverage the relationship that already exists between the CHP and the offtakers for the heat output from the plant. This relationship should enable the CHP to establish electricity sales to the heat network customers without incurring substantial sales and marketing costs. Alternatively, the CHP could market to local customers who are not necessarily part of the heat network as part of a community scheme.

A White Label supply approach may incorporate a number of CHPs and capture the economies of scale that would emerge from multiple sites selling to a large number of customers. For example, a local authority could adopt this role and sell the CHP output to local consumers using their existing relationship with the customers.

The incremental benefit for a CHP to choose this route to market instead of a standard PPA is twofold:

- Firstly, the White Label supply should be profitable in its own right above a certain size. The ability to keep the sales and market expenditure low by leveraging on the unique selling point of the CHP is key to making this approach profitable, even with low customer numbers.
- Secondly, the CHP may be able to capture a greater share of revenue through the PPA if it is tied into the White Label supplier agreement. The actual level of benefits achieved will vary on a case by case basis and there may be a trade-off between the commission rate and level of benefits allocated to the CHP plant.

1.6 Corporate PPA – Sleeving/ Peer-to-Peer

SUMMARY

A variant of the PPA arrangement is a contracting route that allows generators and end users to net their volumes off each other over the distribution network and is known as a sleeved or peer to peer supply. To enable this agreement, a supplier is used as a facilitator by arranging and paying for the transport of that energy across the public grid and managing the risk of a supply and demand mismatch by providing netting (also known as top-up and spill to deal with mismatches between generation and demand volumes) services and deal with balancing..

Sleeving allows a generator to approach demand customers and agree terms that suit both parties. This type of agreement can be between a generator and either one or several demand customers and allows for longer term offtakes to be agreed which creates certainty for both parties.

In essence "sleeving" is an extended offtake agreement insofar as terms for valuing the power will be determined by negotiations between the end customer and generator. The third-party will then take a tolling fee for moving the power across the public network and (usually) providing netting services as required by the customer.

LAs may be well placed to enter into a sleeving arrangement between demand and consumption controlled by them

A peer-to-peer supply is implemented in the same way as a sleeved agreement, but the matching of demand and generation takes place via a peer to peer platform.

The licensed supplier registers all meters in these arrangements and will typically flow network charges through to the parties involved. It will also levy a charge for providing the service.

DESCRIPTION

Sleeving arrangements typically start with negotiations between a generator and an end consumer. Once these are agreed a third-party supplier is usually found to aid the tolling process. This can be a drawn-out negotiation process under traditional sleeving, however a peer-to-peer platform can streamline this in an auction style process.

End consumers in these arrangements tend to be corporate buyers who are looking to benefit from a long-term fixed price for the power and usually the corporate social responsibility (CSR) credentials that come with publicly contracting with a renewable/ low carbon generator. Generators are also attracted to these arrangements as large-scale end users can sign 10-15 year agreements which will be supported by the generator financiers.

The use of sleeving is a popular route to market for generators, as they can effectively agree a guaranteed income stream with a reliable end-user. The route to market is also at a comparatively low cost compared to finding consumers through licence-lite or direct supply arrangements. However, processes are complicated by the requirement for top-up provision services to be provided by suppliers. There are around seven major offtakers who are active in this area (vs. >35 offtakers active in the PPA market), as there is little margin to be made for suppliers and negotiations can be time consuming and complex. As a result of this complexity, and the fact that the PPA market has both high competition and market liquidity, sleeving arrangements have not been used to a large extent.

The concept of peer-to-peer trading is one of increased engagement in the energy market by generators and consumers. In the current market suppliers typically choose where they source their power from, be it renewable, nuclear, fossil fuel-fired or some combination and at what price. In a peer-to-peer traded market consumers can choose where they purchase their power from and generators can choose who to sell to. There also exists the option for these entities to agree a price separate from the supplier, although this is more difficult than pure matching.

CONTRACTURAL ARRANGEMENT

Sleeving contracts are structured as extended offtaker agreements, with price negotiations between the generator(s) and end consumer(s) generally creating a fixed price arrangement. Agreements are typically between 5 and 15 years in length and can be subject to re-negotiation on power price arrangements as well as change in law. Once the generator and end consumer have agreed on price, a supplier is then tendered to provide top-up and spill arrangements. For their services, a supplier will usually charge a "tolling fee" to cover network charges, imbalance payments, top-up and spill and a service fee.

The diagram below shows the contractual arrangements between the key market participants under sleeving and peer-to-peer agreements:

Figure 59: Contractual arrangements between parties under a sleeving arrangement

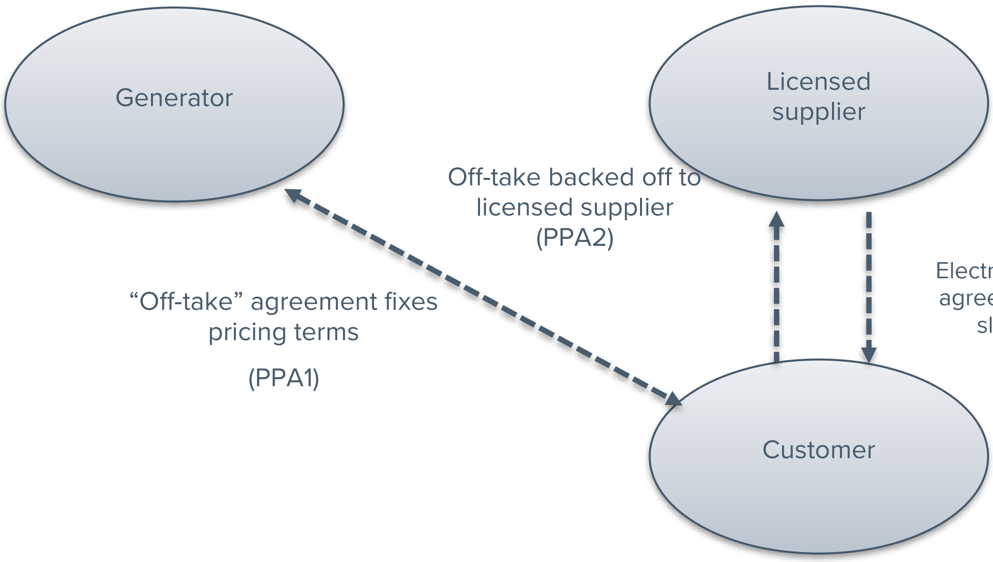
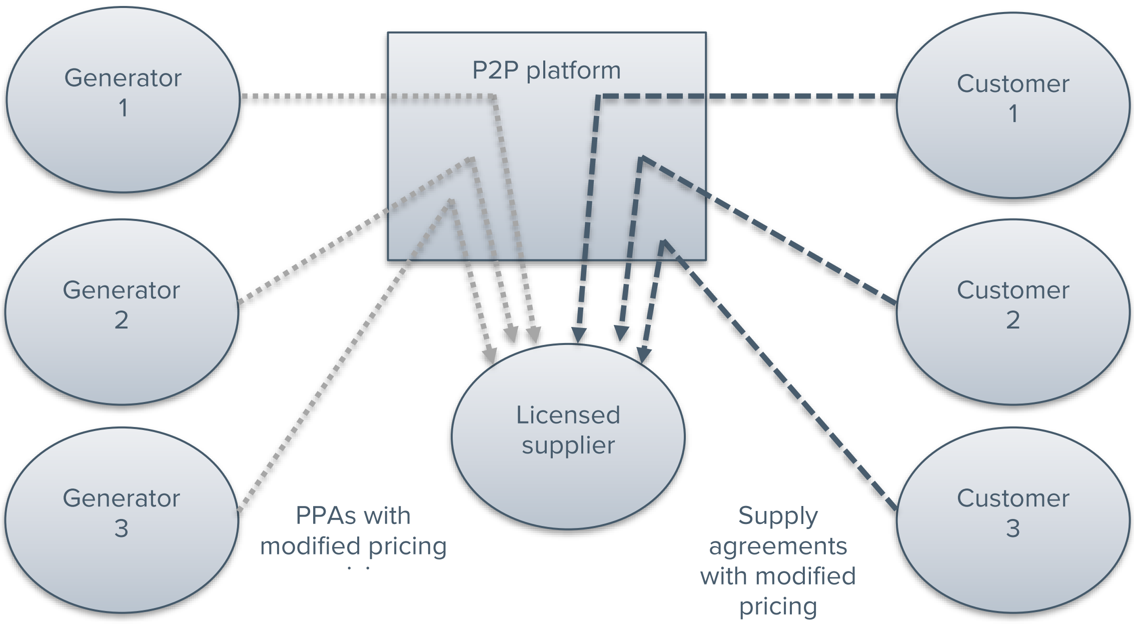


Figure 60: Contractual arrangements between parties under a peer-to-peer arrangement



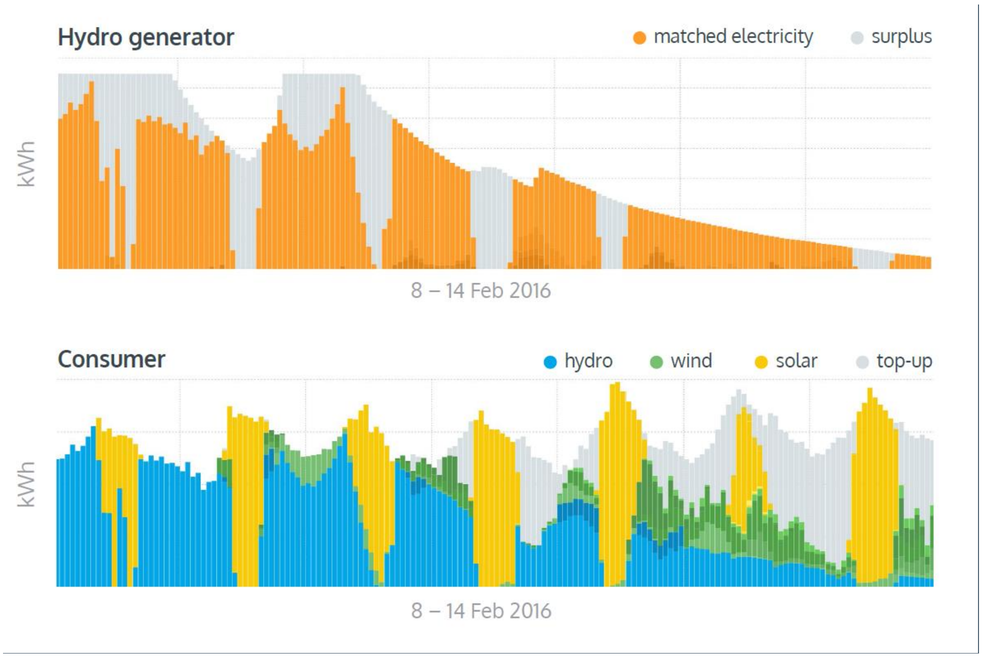
EXAMPLES OF SLEEVING

Sleeving agreements are commercially confidential agreements which are generally not made public.

EXAMPLES OF PEER-TO-PEER

The Piclo online platform, owned and operated by Open Utility, offers peer-to-peer electricity matching for local businesses (not domestic), allowing consumers to match with specific renewable generators (which can be in their locality). It assesses users' price and preference information and matches electricity demand and supply every half an hour. Good Energy provides the supply function, purchasing spill or providing top-up when required. Figure 8 summarises how the generation and consumption volumes can be matched on a half-hourly basis.

Figure 61: Example generation and consumption matching[114]



The Piclo platform recently completed a six-month trial period, using funding from DECC's Energy Entrepreneurs Fund and Nominet Trust. The trial involved 37 consumers and generators from across GB and respondents were actively engaged in the scheme. In the final two months of the trial generators were able to set discount or premium prices for their electricity, but initial uptake was low with only five customers subscribing to different rates. On 23 August 2016, Good Energy announced that, following the initial six month trial period, it had chosen the Piclo platform to enable its business customers to purchase electricity from a wide range of renewable providers across the GB[115]. Therefore peer-to-peer trading is likely to be present in at least one form for some years. However, it is somewhat limited by the market's present inability to settle customers on a half-hourly (HH) basis as the majority of consumers across GB are charged based on an assumed profile of usage rather than actual HH demand data.

[114] Sourced from Piclo – A glimpse into the future of Britain's energy economy: https://www.openutility.com/
[115] Good Energy announcement: https://s3-eu-west-1.amazonaws.com/ou-publications/open-utility-partners-with-good-energy-press-release.pdf

RELEVANCE TO CHP

CHP projects could use sleeving and peer-to-peer PPAs as a route to market, as has been seen with other generators, especially renewables generators.

Negotiations for CHP projects will depend on the scale of the end consumer, as the scale of CHP projects will generally mean that larger business consumers will be needed to “net-off” volumes appropriately. Sleeving is also applicable with wider routes to market and could be used in conjunction with other supply arrangements.

Sleeving and peer-to-peer trading could also facilitate synergies with heat offtake and local heat networks where the same customers being supplied with heat could also contract for the power through a licensed supplier.

Note: Although these types of corporate PPAs are potentially beneficial due to the reduced electricity supply margin, consideration should be given to any additional costs that may be incurred to negotiate and agree the contract. This may include costs of procuring external advice which may exceed the savings achieved through the reduced suppy margin. The long term security offered by these contract arrangements could be of value and should also be considered by the generator and retail customer.

1.7 Corporate PPA – Synthetic PPA

SUMMARY

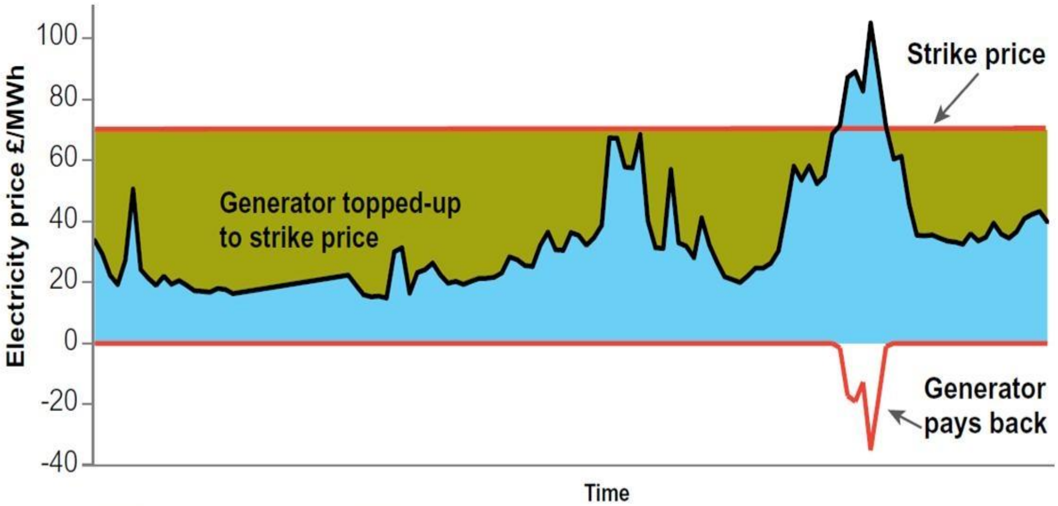
A synthetic PPA is an agreement between a generator and end customer where both parties agree to hedge the price at which they buy and sell electricity from a licensed supplier. Both parties will have a normal contracultural relationship with a supplier (which may or may not be the same company) and the agreement to fix the price will be a standalone agreement that is entirely separate from the supplier. The agreement will only relate to certain elements of the retail price charged by the supplier. This will include the wholesale price and may extend to some other embedded benefits where both parties are exposed to the same elements of cost.

DESCRIPTION

The agreement takes the form of a Contract for Difference (CfD) agreement. A CfD sets down a price at which parties are willing to pay for a product (e.g. the wholesale price of electricity) and where a variance from this price occurs one party will make a payment to the other party to put both parties in the position they would have been in if the change in price had not occurred. This agreed price is called the strike price. The payments made between the parties are called difference payments. CfDs are financial products that are widely used by financial institutions to manage exposure to price volatility. To enable a CfD, there must be a clear reference price to enable the difference payments to be determined. Within the electricity wholesale market, a market index is normally used as the reference price which is likely to be a weighted average price of a traded product such as annual baseload.

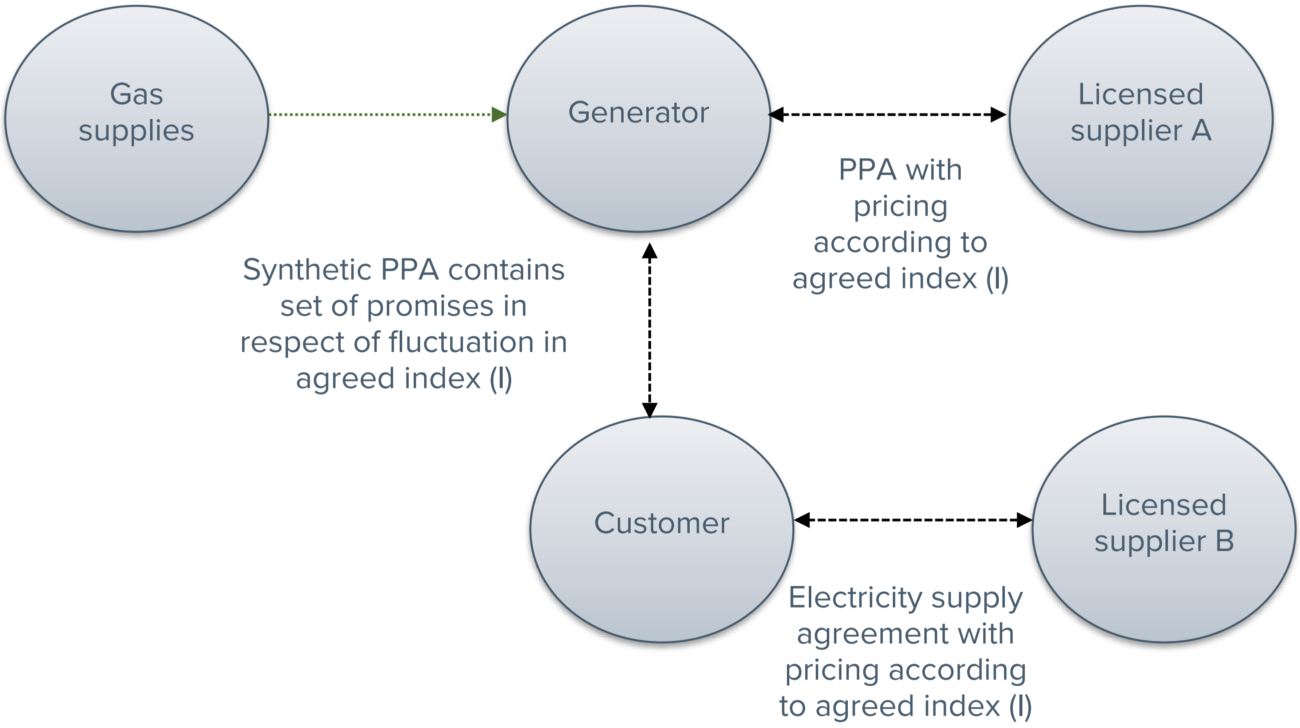
The diagram below shows how the difference payments work under a CfD:

Figure 62: CfD payments against a strike price



The diagram below shows the contractual arrangements between the key market participants under a synthetic PPA arrangement:

Figure 63: Contractual arrangements between parties under a synthetic PPA arrangement



EXAMPLES OF SYNTHETIC PPA

Synthetic PPAs tend to be commercially confidential agreements that are not in the public domain. However, Marks and Spencer signed an agreement which they were happy to make public to demonstrate their proactive approach to energy.[116]

WORKED EXAMPLE OF SYNTHETIC PPA

In the example below a synthetic PPA has been agreed between a generator and demand customer. Each party also has a contract with a supplier which is a PPA for the generator and a supply agreement for the demand customer. The CfD relates to solely the wholesale element of the demand customers bill and the demand customer must ensure that each element of its electricity bill is identified for the duration of the synthetic PPA agreement to ensure the CfD can be settled:

Strike Price - £40/MWh

Reference Price – Wholesale element of demand customers bill

Amount – 8,760MWh pa

[116] As referenced by Burges Salmon - https://www.burges-salmon.com/news-and-insight/legal-updates/corporate-power-purchase-agreements-keeping-it-simple/

The payments across a three-year period are shown in the table below. In the first year the wholesale price element of the demand customers bill is set at £40/MWh which is the same as that agreed under the synthetic PPA and there is no difference payment due. In year 2, the market has risen and the wholesale price has increased to £42/MWh. This results in the generator paying the demand customer £2/MW for the volume fixed (8,760MWh) which places both parties in the same position as if the wholesale market had not risen. From the generators perspective, although a payment has been made under the synthetic PPA, it should have received a similar increase in revenue through the PPA with its supplier which is also linked to wholesale market prices. In year 3, the wholesale element of the demand customers bill has reduced to £39/MWh which means the demand customer pays £1/MWh for the agreed volume to the generator to maintain the position of both parties:

Figure 64: Example CfD difference payments

	Year 1	Year 2	Year 3
Reference Price (£/MWh)	40	42	39
Strike price (£/MWh)	40	40	40
Volume (MWh)	8760	8760	8760
Difference Payment	£0	£17,520	-£8,760
Payment direction	No payment	Generator pays demand customer	Demand customer pays generator

It should be noted that the difference payments under this agreement are meant to protect the position of both parties against movements in the wholesale market. However, the generator is reliant on an offsetting change in revenue under its PPA from its electricity supplier. However, if the generator is unable to generate the volume of electricity agreed under the PPA, it will still be liable for the difference payments, but without the offsetting change in income via the PPA with its supplier. This could be beneficial or an additional cost, depending on the underlying market movement.

RELEVANCE TO CHP

Synthetic PPAs enable reliable generators such as CHP to approach large electricity users and agree a price for their export. Both the supplier and generator will have standard agreements with their electricity suppliers, so no additional value is captured as may be the case under a sleeving or peer-to-peer approach. However, the benefit is that both parties can create long term price security without seeking long term deals from suppliers, which normally command a premium due to the additional risk for the supplier.

1.8 Standard PPA

SUMMARY

A standard Power Purchase Agreement (PPA) (also known as an offtake contract) is a contract between a generator and a licensed BSC signatory party. The BSC signatory, usually a supplier or trading party, will generally manage imbalance and trade or supply the power on behalf of the generator.

Generators see this as a popular route to market as trading and imbalance complexities are passed onto specialist BSC parties. Through the agreement, the generator will be paid a high proportion of the value of the project with a discount applied by the offtaker to reflect their management of volumes and bearing of risk. The PPA may also cover details over who is responsible for despatching the plant and the notification of the planned running regime to assist the supplier in minimising their imbalance position.

PPAs are generally the most straightforward and popular route to market for baseload renewables (including CHP) generators. However, value sharing means that final values captured can be lower than alternative routes to market.

DESCRIPTION

PPAs in the GB market vary by participant but are typically defined as either short-term (6 months to 3 years), medium term (3 to 10 years) or long-term (10 to 15 years). The choice taken by generators on contract varies on their risk profile, financial backing and view of prevailing market prices and trends. Short-term PPAs tend to have a fixed price element, whereas long-term PPAs are usually referenced against a market index for power (e.g. N2eX or APX).

There are over 35 offtakers active in the GB market who offer PPAs of varying lengths and styles based on their business models and credit ratings, an important factor in long-term PPA deals as project backers will want to ensure credit worthiness of the offtaker in any long-term deal. The market remains competitive even for smaller generators under 1MW in size.

CONTRACTUAL ARRANGEMENT

The generator and 'offtaker' will negotiate rates or 'benefit shares' of achieved values based on the technology in question (e.g. power prices, ROCs and embedded benefits). Contracts vary, but most values are quoted in percentage terms against a market reference price.

Typically, percentage discounts to full value will represent the length of agreement (with a shorter agreement having less risk), whether the contract is linked to a market index or set at a fixed price and the type of technology. The table below highlights the general pricing trends.

Figure 65: Power Purchase Agreement: Standard PPA

Consideration	Low	Medium	High
Technology	Intermittent	Less reliable non-intermittent	Reliable non-intermittent
Capacity	<1 MW	1 – 10MW	10MW+
Risk Appetite	Stable revenue	Some market exposure	Full market exposure
Contract Length	Long—10 yr +	3 to 10 yr	< 3yr
Pricing	Fixed	Market reference	Daily price

EXAMPLES OF STANDARD PPAs

Although PPAs tend to be commercially confidential agreements, the E-Power auction has a standardised PPA which can be downloaded from the E-Power website using the following link: http://www.epowerauctions.co.uk/legaldocs.htm

See also the boxout in section 4.5.2 and section 8.2.4

RELEVANCE TO CHP

CHPs will not only need to find offtake for their heat but also for their power. PPAs provide a simple route to market for this power without the need for the CHP generator to sign up to licensing and code arrangements. For embedded (distribution connected) CHP plant, PPAs also offer access to embedded benefits, as offtakers can use the generation to offset their exposure to transmission and other network charges. Embedded benefits can make up over 20% of revenue for some baseload renewables projects and with CHP being a reliable technology it should also access peak periods where embedded benefits are generally highest.

PPAs are also flexible and can be signed in conjunction with broader arrangements such as sleeving or self-supply (see below). Therefore, PPAs could be used as a “backstop” for volumes which are not consumed on site or through self-supply.

Although relatively straightforward to set up and manage, PPAs compared to other routes to market (self-supply and fully licensed supply) will generally offer lower overall value retention as offtakers will be taking a proportion of value in their risk management of the project.

Appendix 3 –Heads of Terms (HoT)

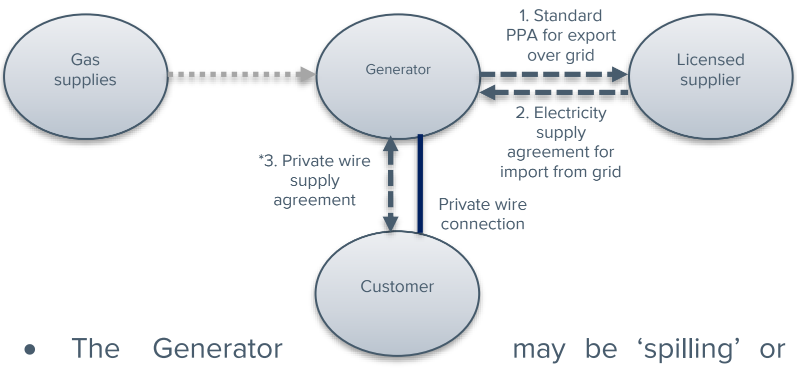
WARNING: This appendix is intended only to serve as a prompt to discussion of some of the key issues likely to arise in the context of the subject matter of this document. Substantive commercial and legal consideration will need to be given to the specifics of the project in hand. The principles flagged below and others relevant to that particular scheme will need to be developed substantially further before the parties enter into fully binding legal agreement or move to a set of binding "heads of terms". This document is no substitute for taking proper legal advice from lawyers experienced in decentralised energy and negotiating the relevant agreements.

Heads of Terms

HoT 1 – Private Wire Supply Agreement

<table>
<tr><th colspan="2">Private Wire Supply Agreement
Parties: [Generator/Supplier] (1) and [Customer] (2)</th></tr>
<tr><td>Description and Assumptions</td><td>

A Private Wire Supply is a supply of electricity made by a supplier taking advantage of the Class C (or Class B) supply licence exemptions. It could also include supplies made taking advantage of the Class A or Class D supply licence exemption.
Here, we assume this is a Generator supply under the Class C supply licence exemption.
Example structure:



The Generator may be ‘spilling’ or ‘exporting’ some electrical output onto the ‘grid’ (usually onto the local, licensed distribution network operator’s network) and may do so under a number of models. Most commonly this will be under a standard PPA (contract 1 in the above example structure).
The Generator supplies on-site Customers under the Class C supply exemption. This permits the Generator/supplier to supply electricity:

it has generated itself; and
any supplied to the Generator/supplier by a licensed supplier.

</td></tr>
</table>

	• The Generator/supplier will have in place an agreement for the supply of electricity to the site from the grid (contract 2 again above). This may be a fairly standard supply agreement. • The Generator/supplier will also have in place a Private Wire Supply Agreement(s) with its Customer(s) (contract 3 again above and summarised here). • In accordance with the requirements of the Class C supply exemption, the Customer(s) will be on the "same site" or connected by "private wire" to the Generator's generation facility.
Parties	(1) *[Generator] (as generator and supplier)* (2) *[Customer]*
Conditions precedent	*[Relevant conditions to commencement]*[117] *[Obligations usually on the Generator to have satisfied the Conditions by [ ]]* *[If Conditions are not met, agreement to cease, except [ ]*[118]*]*
Description and operation of the generating facility	*[The Buyer will want full details of the generating station]* *[The Generator usually accepts an obligation to operate in accordance with law, good industry practice, etc.]*
Connection capacity and installing the private wire connection	*[The Generator will usually be under obligation to obtain and maintain its connection to the gird and to deal with any permitting required for operation of the generating station.]* *[Because the Generator's grid connection will be subject to limits, and due to the aggregation of demand across the site and between Customers, the*

[117] These could relate, for example, to third party consents having been obtained, the generating plant being commissioned, etc.
[118] Insert relevant provisions which shall survive expiry (such as confidentiality).

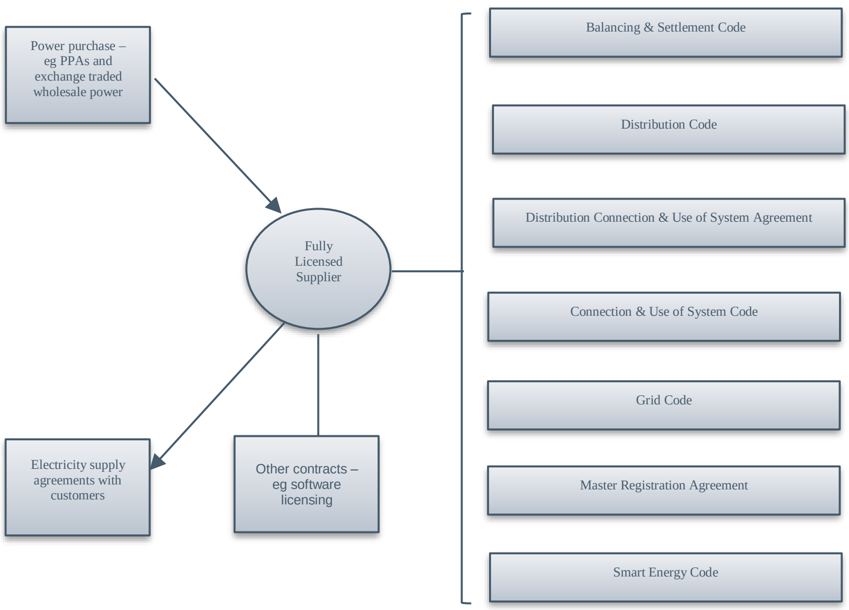
	Generator will usually want to impose a maximum load that the Customer can draw.] *[If the private wire connection is not already in place, additional provisions (and/or an additional set of contracts) will be needed to address construction of the private wire itself]*
Sale of electricity	*[The Generator will sell and the Customer will buy electricity]*
Metering	*[Provisions govern installation, ownership and registration of meters, including appointment of Meter Operator and giving access to Buyer's Data Collector and Data Aggregator]* *[Provisions will also deal with meter accuracy and how to deal with meter errors]*
Forecasting, output data, volume tolerances and imbalance risk	*[The Generator may want forecasts of the Customer's expected demand. Depending on the nature of the Customer's operations, it will be possible to give forecasting that is:* • *more or less detailed;* • *more or less reliable.]* *[From the Customer's perspective, it is important not to be under obligation to provide unrealistic forecasting information. However, the more information that is given to the Generator, the better they should be able to mitigate their own imbalance risk. This should allow them to charge less for taking this risk.]* *[Some Generators will allow tolerance bands. This permits some deviation from projected output before imbalance costs are passed to the Customer. This allows some sharing of imbalance risk]*
Other benefits	*[Generators and Customers may agree to share the value of any embedded benefits received. The share agreed will vary from project to project and depends upon a variety of factors.]*

Price and payment	*[The Generator may charge at different rates for:* • *electricity it generates itself; and* • *electricity it imports from the grid.]* *[Typically, the Generator will seek to recover all costs it incurs when it is importing for (and paying for) electricity from the grid. This will include all commodity and all system costs. On the other hand, electricity generated by the Generator should enjoy various embedded benefits and, so, may be cheaper. As a result, Customers will normally want to see that the Generator maximises the amount of electricity it supplies from its own generation output and minimises the amount of grid import relied on.]* *[Payments will usually be adjusted to reflect:* • *the cost of any electricity import needed (including associated system costs) and imbalance charges, where demand was higher than generation output – this is usually restricted to situations the Generator is not in default of generation output commitments, maintenance commitments, etc.* • *VAT and any other applicable taxes]* *[Provisions should include time for payment and when interest starts to run on late payments.]* *[Generator's may be concerned to make sure that their Customer has sufficient financial standing always to meet its payment obligations to them. Risk of non-payment may be mitigated by the fact the private wire Customers are often also tenants of the Generator]*
Change in law	*[Change in law provisions will generally pass most change in law risk to the Customer. However, it is important to distinguish between changes that the Generator can/will simply pass on to its customers, at one end and which are reasonable for the Customer to assume responsibility for (e.g. because it would under any normal electricity supply contract) and changes that purely go to the cost of running a generating station, at the other (and which it may be unreasonable to expect Customers to assume.]*
Force Majeure	*[Force Majeure provisions are seen in most Private Wire Supply Agreements, with familiar suspension wording and termination for extended Force Majeure. The more technically complex the generating station, the more carefully the Force Majeure wording will need to be studied.]*
	[Termination will normally be possible for material breach of contract by

Termination	*either party (including non-payment), insolvency and extended for Force Majeure]* *[On termination, in addition to settling pre-termination liabilities and any market exposures, the parties will want to address compensation for any stranded investments. What is reasonable will depend very much on the specifics of the project.]*
Disputes	*[Various approaches to dispute resolution are common amongst PPA providers. These generally escalate through management perhaps to an appointed 'expert', under an agreed set of procedures, or to an external body, such as the Electricity Supply Industry Arbitration Association of England and Wales]*
Boilerplate:	○ Status of the Agreement ○ No partnership or agency ○ Confidentiality ○ Third Party Rights ○ Notices ○ Variation and Waiver ○ Invalidity and Severability ○ Entire Agreement ○ Governing Law

Heads of Terms

HoT 2 – Full Licence

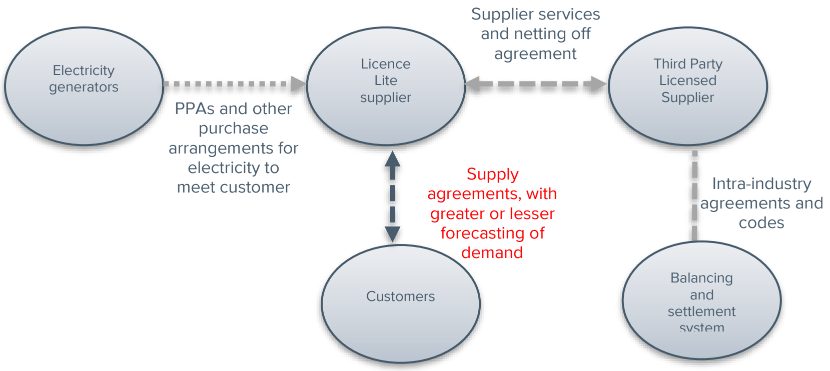
Full Supply Licence	
Description and Assumptions	• A fully licensed supplier must enter into electricity supply agreements (see above) and power purchase agreements (see above) or other purchase agreements. It must also accede to a suite of intra-industry agreements and codes to participate in the regulated electricity market over licensed wires. • An overview of some of the key intra-industry agreements and codes is set out below. These are not subject to negotiation, so no HoTs are included for these. 

Heads of Terms

HoT 3 – Licence Lite

<table>
<tr><th colspan="2">Licence Lite</th></tr>
<tr><td>Description and Assumptions</td><td>

A Licence Lite supply arrangement requires the Licence Lite Supplier to hold an electricity supply licence and to do all those things that a licensed electricity supplier would normally do – except for those compliance functions that it is allowed to outsource to another fully licensed ‘Third Party Licensed Supplier’
The outsourcing of those compliance functions is addressed in a Supplier Services and Netting Off Agreement in the structure illustrated below.



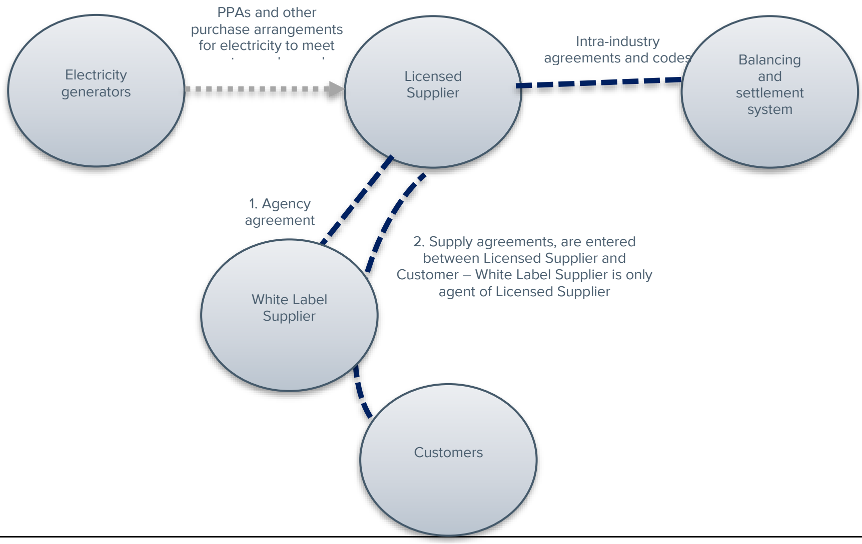
</td></tr>
<tr><td>Supplier Services and Netting Off Agreement</td><td></td></tr>
<tr><td>Parties</td><td>(1) [Licence Lite Supplier] (as supplier with dispensation from complying</td></tr>
</table>

	with Standard Licence Conditions 11.1 and 11.2) (2) *[**Third Party Licensed Supplier**] (as supplier who will meet the requirement of Standard Licence Conditions 11.1 and 11.2 on behalf of Licence Lite Supplier)*
Terms	*[The agreement describes the contractual relationship between the Licence Lite Supplier and Third Party Licensed Supplier. It sets out, to Ofgem's satisfaction, how industry code compliance is achieved by the Third Party Licensed Supplier on the Licence Lite Supplier's behalf.]* *[The agreement addresses:* • *the nature of senior/ junior relationship (e.g. trustee, beneficiary relationship);* • *contract duration;* • *the respective responsibilities of each of the parties to ensure code compliance;* • *explicit agreement from the Third Party Licensed Supplier that it will ensure code compliance on behalf of the Licence Lite Supplier;* • *dispute resolution processes;* • *arrangements for continuation of supply to customers where the agreement is terminated;* • *data privacy and exchange arrangements;* • *processes for identifying the Licence Lite Supplier's meters (and customers);* • *payment arrangements; and* • *day-to-day operation service specification.]* *[Because the Third Party Licensed Supplier is most likely to be providing back-up, top-up and balancing services to the Licence Lite Supplier, the agreement also covers:* • *the purchase by the Third Party Licensed Supplier of any excess generation from the Licence Lite Supplier's generation portfolio;* • *the supply by the Third Party Licensed Supplier of electricity to meet any shortfall in the Licence Lite Supplier's generation portfolio's ability to meet the Licence Lite Supplier Customers' electricity demand; and* • *the provision of balancing services.]* *[It may also be valuable for the Licence Lite Supplier to procure certain other services from the Third Party Licensed Supplier, depending on the internal resources of the Licence Lite Supplier and other platforms it can access]*

Heads of Terms

HoT 4 – White Label Supplier Agreement

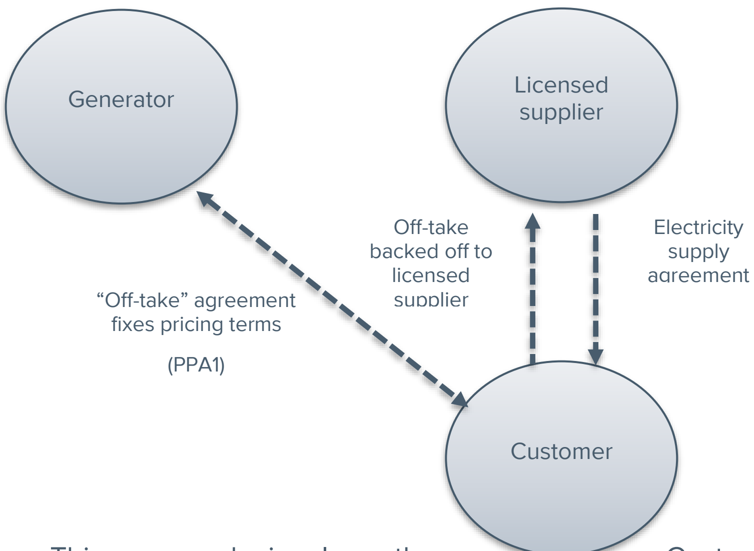
White Label Supplier Arrangement **Parties:** ***[White Label Supplier], [Licensed Supplier]*** **and** ***[Customers]***	
Description and Assumptions	• A White Label Supplier is an unlicensed company that has a contractual agreement with a Licensed Supplier to sell electricity to consumers using the White Label Supplier's brand. The White Label Supplier might be an existing and well-known brand, such as a supermarket chain or a local authority or it may have been set up specifically (e.g. to service a particular part of the community). • The White Label supplier will need an agency agreement with a fully licensed supplier to sign-up Customers on behalf of the Licensed Supplier. • This allows the White Label Supplier to rely on the Licensed Supplier for all the regulatory interaction with industry codes, billing of customers and customer service functions, using their existing systems and infrastructure to manage the electricity supply to the end customer. • The split of supply functions between the Licensed Supplier and the White Label Supplier will depend on their commercial objectives. Some White Label Suppliers will want the Licensed Supplier to undertake as many business functions as possible, whereas others may provide some functions themselves, particularly if they already have the infrastructure in place (for example, they may already have a call centre and prefer to use their own service in this regard).

	Example structure: 
1. White Label Supplier Agreement (or Agency Agreement)	
Parties	(1) *[**White Label Supplier**] (as agent)* (2) *[**Licensed Supplier**] (as principal)*
White label terms	*[The White Label Supplier will be appointed as the Licensed Supplier's agent for the specified purpose. This will cover signing up Customers that the Licensed Supplier will supply with electricity. It may be restricted to certain categories of Customer.]* *[The appointment will also address any split of functions, particularly where the White Label Supplier has its own infrastructure – e.g. to service customer enquiries, etc. However, under this model, all regulatory functions will only ever be performed by the Licensed Supplier.]* *[The White Label Supplier may be paid a fee for attracting new Customers to the Licensed Supplier]*

2. Supply Agreement	
Parties	(1) *[**Licensed Supplier**] (signing directly as supplier) or [**White Label Supplier**] (signing as disclosed agent of Licensed Supplier)* (2) *[**Customer**] (as customer and consumer of electricity)*
Supplier's terms of supply	*[Per above, these will be the Licensed Supplier's terms of supply.]* *[They may contain a tariff structure specific to the White Label arrangement]*

Heads of Terms

HoT 5 – Sleeving Agreement

Sleeved Supply **Parties:** ***[Generator]*** **(1) and [Customer] (2) and** ***[Licensed Supplier/Offtaker]*** **(3)**	
Description and Assumptions	• A sleeved supply is where a Generator forms an agreement with a demand Customer to supply them with electricity over the distribution network. To enable this agreement, a Supplier is used as a facilitator by arranging for the transport of that electricity across the public grid and managing the risk of a supply and demand mismatch or 'imbalance'. • Sleeving allows a Generator to approach demand Customers and agree terms that suit both parties. This type of agreement can be between a Generator and either one or several demand Customers and allows for longer term offtakes to be agreed which creates certainty for both parties. • There are various approaches that can be taken to structuring this arrangement. The most common one is illustrated below:  • This approach involves the Customer buying legal title to the Generator's output directly from the Generator

	(under PPA1) but then immediately on-selling title to that electricity to the Supplier (under PPA2). The Supplier then sells the electricity back to the Customer under a supply agreement that wraps in the Generator's electricity. • The Supplier's involvement allows the electricity to be conveyed from the Generator to the Customer over the licensed transmission and distribution systems and for the Supplier to provide additional back-up and top-up supplies to the Customer. • Because of the involvement of the Customer in the middle of a back-to-back PPA chain, each of the Generator, Customer and Licensed Supplier will be very sensitive to the credit-worthiness of the others in the chain. • Other approaches are possible but are not summarised here.
PPA 1	
Parties	(1) *[**Generator**] (as generator of power)* (2) *[**Customer**] (as initial off-taker)*
PPA terms	*[The simplest approach is for the Generator and Customer to have identified an amenable Supplier and to use the appropriate form of the Supplier's PPA as the basis for this PPA. The Supplier may have been selected following a competition or, for example, because it is the Customer's preferred Supplier. This approach helps avoid the Generator and Customer negotiating PPA terms that no Supplier will back off]* *[The Supplier's standard PPA terms are modified to recognise that:* • *the Customer is not a licensed supplier;* • *the Customer is on-selling to the Supplier, who is a licensed supplier;* • *title to generated electricity passes to the Customer at the export meter point;* • *any Special Conditions required by the Customer]*
Special Conditions	*[Price/Term: the Generator and Customer most likely want to agree a longer term, fixed price for electricity than is otherwise available in the regular PPA market – this can give the Generator greater revenue certainty and the Customer greater cost certainty than either is otherwise likely to be*

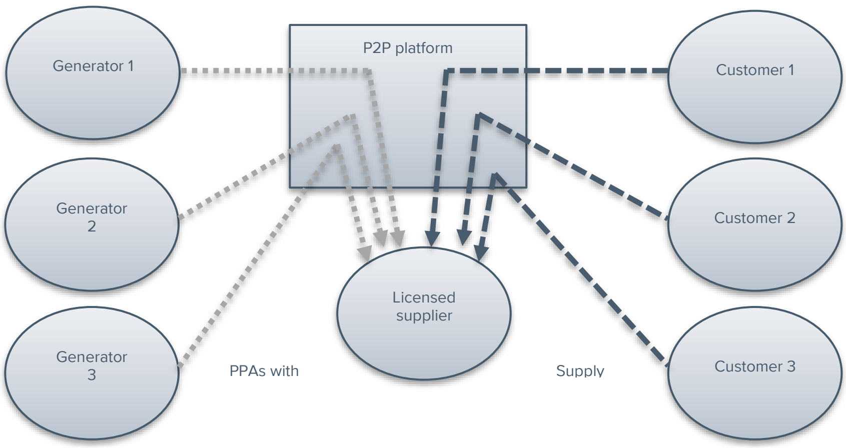
	able to achieve] *[Fuel source/Sustainability: the Customer may have special requirements over and above those required by statutory schemes]* *[Any other factors important to the Customer:]*
Other benefits	*[The Generator may agree to sell and the Customer to buy additional products generated along with electrical output (such as ROCs).]* *[Note: the Generator and the Customer may agree to share the value of any embedded benefits available, associated with the generation facility.]*
PPA 2	
Parties	(1) *[**Customer**] (as seller of power)* (2) *[**Supplier**] (as off-taker)*
PPA terms	*[Per above, this will be the appropriate form of the Supplier's PPA.]* *[The Supplier's standard PPA terms are modified to recognise that:* • *the Customer is not, itself, the generator but procures compliance by the Generator with all relevant terms;* • *the Customer is on-selling to the Supplier, who is a licensed supplier;* • *title to generated electricity passes to the Supplier at the export meter point;* • *the Customer's Special Conditions would not flow through to the Supplier (unless having a bearing on discharge of obligations relevant to the Supplier]*
Supply Agreement	
Parties	(1) *[**Supplier**] (as seller/supplier)*

	(2) *[**Customer**] (as customer and consumer of electricity)*

Supplier's terms of supply	*[Per above, this will be the Supplier's terms of supply.]*
	
	[The Supplier's standard terms of supply are modified to recognise that:
	• *the Customer's electricity demand is to be met by the Supplier but this will involve:*
	    ○ *notionally utilising electricity sourced from the Generator's export output over the grid (via the back-to-back PPA structure); plus*
	    ○ *other electricity (sourced by the Supplier) as may be needed to meet the Customer's electricity demand where this is different from the Generator's export output (i.e. top-up, back-up and short-term balancing);*
	• *title to delivered electricity passes to the Customer at the demand meter point.]*
	
	[The price paid for supplied electricity will depend upon:
	• *the nature of the Generator's generation source;*
	• *whether and how much the Supplier has paid for the Generator's export output under PPA2;*
	• *any margin agreed between the Supplier and the Customer that the Supplier can charge for administering the sleeving arrangement;*
	• *system costs incurred (including imbalance charges and how it has been agreed that imbalance risk should be apportioned) but with a default assumption that the Supplier will pass through all system costs at their full value.]*

Heads of Terms

HoT 6 – Peer to Peer Agreement

Peer to Peer Supply **Parties:** ***[Generators],*** **[Customers], and** ***[Licensed Supplier]***	
Description and Assumptions	• Various different approaches may be possible to implement a peer-to-peer supply. The only model currently operating adopts an approach that can be compared to a sleeved supply. Generators and demand Customers (who are not on the 'same site' or connected via 'private wire' but who are all half-hourly metered) agree a pricing structure through a peer-to-peer platform and a notional supply of that power is effected over the grid through a licensed Supplier. The Supplier also manages all risk of a supply and demand mismatch or 'imbalance'. • Peer-to-peer matching allows demand Customers to build a portfolio of preferred generation assets/types and reach agreement on pricing with Generators. • A structure for implementing peer-to-peer supply is illustrated below: 

	• This approach involves each Customer and each Generator entering into terms of use of the peer-to-peer platform. These terms govern use of the platform and rules on setting price amongst other things. • Each Generator also enters into a power purchase agreement. The principal purchaser is the Licensed Supplier. • Each Customer also enters into a supply agreement. The principal seller is the Licensed Supplier.
Peer-to-peer terms	
Parties	(1)[n] *[**Generators**] (as potential sellers of electricity)* (2)[n] *[**Customers**] (as potential buyers of electricity)* (3) *[**Licensed Supplier or other**] (as peer-to-peer host)*
Peer-to-peer terms	*[These will allow potential Generators and potential Customers to be introduced]* *[They are the 'rules of the club' so will be specific to the USP of the particular peer-to-peer platform. However, they are likely to address things such as:* • *how Generators describe their generating projects, the stage they are at in their development before they can come onto the platform, the amount of export electricity they expect to be able to sell;* • *how Customers describe their demand profile;* • *how Generators and Customers are expected to behave in terms of price setting]*

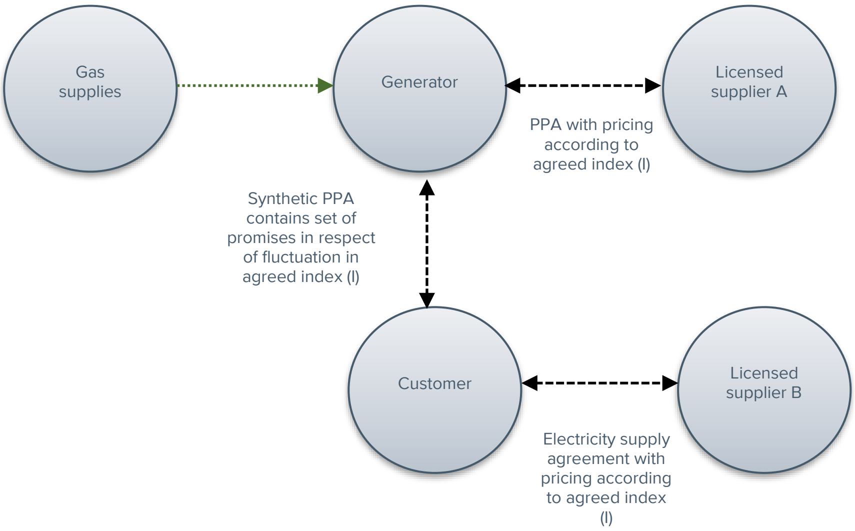
PPA	
Parties	(1) *[**Generator**] (as generator of electricity)* (2) *[**Licensed Supplier**] (as off-taker)*
PPA terms	*[These are likely to be the Licensed Supplier's standard PPA terms (see HoTs 1).]* *[The Licensed Supplier's standard PPA terms are modified to recognise that:* • *the Generator and a Customer or Customers will agree the price for the Generator's export output through the peer-to-peer platform;* • *when the Generator is generating as expected and the Customers are consuming as expected, the price agreed between them applies;* • *when there is surplus export output, the Licensed Supplier's pricing prevails and sets the price paid for the surplus export output]*
Supply Agreement	
Parties	(1) *[**Licensed Supplier**] (as seller/supplier)* (2) *[**Customer**] (as customer and consumer of electricity)*

Supplier's terms of supply	*[Per above, this will be the Supplier's terms of supply.]*
	
	[The Supplier's standard terms of supply are modified to recognise that:
	• *the Customer's electricity demand is to be met by the Supplier but this will involve:*
	    ○ *notionally utilising electricity sourced from the Generator's or Generators' export output over the grid; plus*
	    ○ *other electricity (sourced by the Supplier) as may be needed to meet the Customer's electricity demand where this is more than the Generator's export output (i.e. top-up, back-up and short-term balancing);*
	• *title to delivered electricity passes to the Customer at the demand*

	meter point.] *[The price paid for supplied electricity will be:* • *when export output from selected Generators is sufficient to meet the Customer's demand, the price agreed between Generator(s) and Customer(s) using the peer-to-peer platform prevails;* • *when there is a shortfall in the amount of export output from selected Generators relative to Customer demand, the Licensed Supplier's pricing prevails]*

Heads of Terms

HoT 7 – Synthetic Power Purchase Agreement

Synthetic Power Purchase Agreement **Parties: *[Generator]* (1) and [Customer] (2) and *[Licensed Supplier/Offtaker]* (3)**	
Description and Assumptions	• A synthetic PPA allows a Generator and a Customer to negotiate only the components of an offtake agreement that matters to them and to leave the complex regulatory matters to others. • A regular PPA will exist between the Generator and a Supplier and a regular Supply Agreement will exist between a Supplier and the Customer. • Consequently, a synthetic PPA might only cover price and a guarantee of origin. • There are various approaches that can be taken to structuring this arrangement. The most common one is illustrated below: 
PPA	

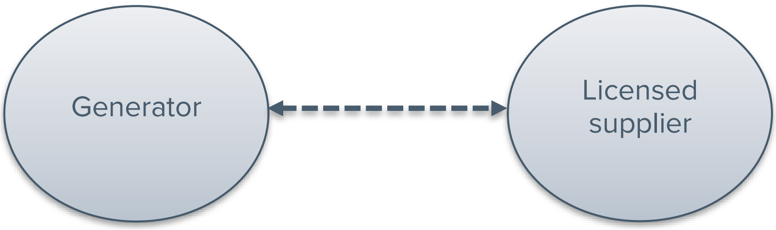
Parties	(1) *[**Generator**] (as generator of electricity)* (2) *[**Supplier**] (as off-taker)*
PPA terms	*[This uses the appropriate form of the Supplier's PPA as the basis for this PPA (See HoTs1)]*
Supply Agreement	
Parties	(1) *[**Supplier**] (as seller/supplier)* (2) *[**Customer**] (as customer and consumer of electricity)*
Supplier's terms of supply	*[Per above, this will be the Supplier's terms of supply.]*
Synthetic PPA	
Parties	(1) *[**Generator**]* (2) *[**Customer**]*

Terms of guarantee or contract for difference	*[This approach allows the Generator and the Customer to focus only on what happens when the value of the chosen index rises above or falls below a certain level.]* *[The index is used to determine the price paid for the Generator's output and used to determine the Customer's supply price. Most monetary flows will, therefore, be under the PPA (from Supplier to Generator) and under the Supply Agreement (from Customer to Supplier).]* *[They synthetic PPA approach allows the Generator and the Customer to agree to payment adjustments between them only to 'correct' for deviation from the agreed level or index. The effect is to stabilise the price for each of them and involves smaller money flows. The value of the contract and, therefore, sensitivity to counterparty creditworthiness is, therefore, lower than with the sleeved supply agreement.]* *The synthetic PPA is also likely to include a requirement for guarantees of origin but may also include other bespoke requirements important to Customer and/or to Generator].*

Heads of Terms

HoT 8 – Standard Power Purchase Agreement

Standard Power Purchase Agreement **Parties: *[Generator]* (1) and *[Licensed Supplier]* (2)**	

Description and Assumptions	
	
	• The generator will be 'spilling' or 'exporting' some electrical output onto the 'grid' (usually onto the local, licensed distribution network operator's network).
	• The generator will seek a number of offerings from potential licensed supplier off-takers.
	• Off-takers will pitch different offers, varying by:
	  ○ the price they pay for electricity exported;
	  ○ the proportion of any 'embedded benefits' they offer;
	  ○ the extent of forecasting and imbalance risk they take as opposed to the generator;
	  ○ their own credit rating;
	  ○ their own terms and conditions.
	• In nearly all cases, the generator will NOT produce the power purchase agreement and will only negotiate the terms of the off-takers standard form power purchase agreement. Therefore, these "HoT"s can only serve to flag a few key points to look for in the Buyer's PPA drafting. This typically comes either in the form of: (a) consolidated PPA or (b) as a separate commercial 'proposal' plus general terms and conditions (and, potentially, special terms and conditions).

Parties	(1) *[Generator]*

	(2) *[Licensed Supplier (as off-taker)]*
Conditions precedent	*[Relevant conditions to commencement]*[119] *[Obligations usually on the Generator to have satisfied the Conditions by [ ]]* *[If Conditions are not met, agreement to cease, except [ ]*[120]*]*
Description and operation of the generating facility	*[The Supplier will want full details of the generating station]* *[Obligation usually imposed on the Generator to operate in accordance with law, good industry practice, etc.]* *[The Generator will usually be under obligation to obtain and maintain its generation connection]*
Sale of electricity	*[Provisions govern passage to Supplier of title to export electricity for all purposes, including for the purposes of the BSC]* *[If the generating facility is earning ROCs, a restriction should be imposed on the Supplier's onward sale of electricity to GB consumers only]*
Metering	*[Provisions govern installation, ownership and registration of meters, including appointment of Meter Operator and giving access to Supplier's Data Collector and Data Aggregator]* *[Provisions will also deal with meter accuracy and how to deal with meter errors]*
Forecasting, output data, volume tolerances and imbalance risk	*[The Supplier will want forecasts of expected export output. Depending on the nature of the technology used, it will be possible to give forecasting that is:* • *more or less detailed;*

[119] These could relate, for example, to third party consents having been obtained, the generating plant being commissioned, etc.
[120] Insert relevant provisions which shall survive expiry (such as confidentiality).

	• *more or less reliable.]* *[From the Generator's perspective, it is important not to be under obligation to provide unrealistic forecasting information. However, the more information that is given to the Supplier, the better they should be able to mitigate their own imbalance risk. Where the Supplier is taking imbalance risk, better output predictability should allow them to charge less for taking this risk. On the other hand, if the Generator is able to tightly control their electrical output, it may be in their interests to retain imbalance risk. They would then face a bigger risk of incurring imbalance costs if their output is not as expected, but, if they operate as expected, they should receive a better price for their export electricity.]* *[Some Suppliers will allow tolerance bands. This permits some deviation from projected output before imbalance costs are passed to the Generator. This allows some sharing of imbalance risk]*
Other benefits	*[The Supplier may agree to buy additional products generated along with electrical output (such as ROCs).]* *[Suppliers will usually agree to share the value of embedded benefits. The share agreed will vary from Supplier to Supplier and depends upon the particular project and other factors.]*
Price and payment	*[Price may be determined in a number of different ways. This may include – for example:* • *for half-hourly metered export output, a price applicable for any given settlement period, aggregated into a payment due for export output over a given contract period;* • *the price may be determined by reference to an agreed index;* • *a flat price may be applied to any export output achieved over a given contract period;* • *price fixing may be for the duration of the agreement or for shorter periods – under some PPAs, the Generator can serve a price fix notice to switch from a fully variable market price to a fixed price offered by the Supplier]* *[Payments will usually be adjusted to reflect:* • *additional payments for additional products bought – e.g. ROCs* • *additional payments for additional benefits realised – e.g. embedded benefits* • *deductions for imbalance charges passed through to the Generator, where output was not as predicted*

	• *other 'pass through' charges (these are charges incurred by the Supplier associated with dealing with the Generator's export output)* • *VAT and any other applicable taxes]* *[Provisions should include time for payment and when interest starts to run on late payments.]* *[Generator's may be concerned to make sure that their Buyer has sufficient financial standing always to meet its payment obligations to them. This may be particularly relevant to larger CHP installations. Risk of non-payment can be reduced by shortening contract, billing and payment periods and/or by seeking additional financial security.[121]]*
Change in law	*[Change in law provisions will generally pass most change in law risk to the Generator. However, it is important to distinguish between changes that the Supplier can/will simply pass on to its customers, at one end (and which are reasonable for the Supplier to assume responsibility for) and changes that purely go to the cost of running a generating plant, at the other (and which it would be unreasonable to expect the Supplier to assume). The interaction between some costs and the wholesale price of electricity can make the commercial dynamic and negotiation more complex.]*
Force Majeure	*[Force Majeure provisions are seen in most PPAs, with familiar suspension wording and termination for extended Force Majeure. The more technically complex the generating facility, the more carefully the Force Majeure wording will need to be studied.]*

[121] Although many of the biggest suppliers will not give any additional financial guarantee.

Termination	*[Termination will normally be possible for material breach of contract by either party (including non-payment), insolvency and extended for Force Majeure]* *[On termination, in addition to settling pre-termination liabilities, the parties will want to address closing out their market exposures (if any) according to the pricing structure they have agreed. Where market exposure arises, the termination position could be adverse or favourable to the Generator or Supplier, depending on market conditions. So it is important to make sure that wording captures potential 'upside' and not just 'downside' for the Generator.]*
Disputes	*[Various approaches to dispute resolution are common amongst PPA providers. These generally escalate through management perhaps to an appointed 'expert', under an agreed set of procedures, or to an external body, such as the Electricity Supply Industry Arbitration Association of England and Wales]*
Boilerplate:	○ Status of the Agreement ○ No partnership or agency ○ Confidentiality ○ Third Party Rights ○ Notices ○ Variation and Waiver ○ Invalidity and Severability ○ Entire Agreement ○ Governing Law

Appendix 4 – Embedded Benefits Summary

Transmission Network Use of System (TNUoS) charges

TNUoS charges are applied to suppliers in respect of the demand customers they supply for the use of the transmission network. These charges vary across the country which is split into regional zones. The initial allocation of TNUoS charges to demand is 73% with the remainder recovered from transmission connected generation. A further adjustment is then made to ensure the average charge to transmission connected generation does not exceed a €2.5MWh cap[122] which is set down in European legislation. The result of the additional constraint of the cap has meant that the proportion of TNUoS charges recovered from transmission connected generation has fallen from 27% and is forecast at around 10% in 2020-21. The demand charge is applied in one of two formats depending on whether the supplier's customer is settled on a half hourly basis or non-half hourly:

- Where the customer is settled half hourly the TNUoS charge is applied as a £/kW charge based on the average consumption in the three highest half hours of demand between November and February separated by 10 days. This is known as the Triad charge.
- Where the customer is settled non-half hourly, the TNUoS cost is charged on a unit basis in p/kWh based on the total units consumed between 16:00 and 19:00 across the year.

Where a supplier contracts with a half hourly metered generator for their export, the generation within the Triad half hours is offset against the supplier's Triad demand within the same GSP group and reduces the supplier's TNUoS bill. Where the supplier does not have an offsetting demand, the export is treated as negative demand and the supplier receives a credit for the generation. The amount by which the Triad bill is reduced by or the credit received by the supplier is termed the **Triad benefit**.

Balancing Services Use of System (BSUoS)

BSUoS charges recover all the costs incurred by the system operator in balancing the system. They are split 50%/50% between suppliers and transmission connected generation. The charge is a unit based charge in £/MWh and varies by half hour.

The application of this charge to suppliers is based on their net consumption at the GSP and consequently any contracted generation will offset the demand and reduce the BSUoS bill for the supplier by the corresponding amount in each half hour. Where a supplier does not have an offsetting demand the export is treated as negative demand and a credit is applied.

Transmission Losses

Transmission losses are the difference between the volumes entering the transmission system and those exiting. Losses are around 1.7% and currently applied 45% to transmission connected generation and 55% to demand connected to the transmission network (mainly electricity suppliers). Losses are derived for each half hour and the same rate is applied across GB.

Supplier's volumes at GSP are grossed up by transmission losses before settlement. The ability of suppliers to offset distributed generation export against demand results in transmission losses being applied to a smaller demand and consequently, this is a further saving that accrues to embedded generation. Where a supplier does not have demand within the GSP group, the export from the embedded generator is increased by transmission losses.

[122] Implemented in October 2014 via CUSC modification proposal 224

It should be noted that the current arrangements will change following the CMA investigation into the electricity industry. The CMA recommended that locational transmission losses should be introduced and this has been enacted through the BSC change proposal P350 which was approved in March 2017. The planned implementation date is 1 April 2018.

Capacity Market Supplier Charge

The costs of running the capacity market will be recovered from suppliers based on their market share of consumption at time of peak which is defined as between 4pm and 7pm on working days, November to February. This charge will apply to a supplier's consumption after any embedded generation that is allocated to the supplier has been netted off. Consequently, the CMSC has resulted in a new embedded benefit that can be attributable to embedded generation. It should be noted that any payments received by embedded generation under the capacity market does not exclude them from receiving the CMSC as an embedded benefit. However, BEIS has recognised that this means that some generators may receive a double benefit and intends to remove the CMSC as an embedded benefit from April 2018.

Assistance for Areas with High Distribution Costs (AAHDC)

GB customers pay a subsidy to assist customers in Scotland with the high cost of distributing electricity which arises due to the spread of the population across the area. This charge is applied as a single unit based charge that applies across the year to each supplier based on their settled consumption. As the consumption for each supplier is derived after embedded generation has been deducted, the AAHDC becomes an embedded benefit. Where the supplier does not have offsetting demand, the generation is treated as negative demand and a credit is received.

Residual Cashflow Reallocation Cashflow (RCRC)

RCRC charges arise from balancing the residual cashflow within the balancing mechanism once all payments to or from balancing mechanism participants within a half hour have been made. The residual is allocated to all BSC parties and is charged on a unit basis which varies by half hour. The charge can be positive or negative. As the consumption for each supplier is derived after embedded generation has been deducted, the RCRC becomes an embedded benefit when the adjustment is positive for demand. As this element switches frequently between positive and negative values and averages out at close to zero, this report does not focus further on RCRC as an embedded benefit.

Generator Distribution Use of System (GDUoS)

DNOs provide all Low Voltage (LV) and High Voltage (HV) connected generation with a credit based on the amount of units exported. For intermittent generation this credit is a single unit rate in p/kWh that applies to all units exported. For non-intermittent generation, the credit is split into three timebands labelled red, amber and green with the credit unit rate highest in red, lower in amber and lowest in the green timeband. The time periods for which the red, amber and green timebands apply vary by each DNO.

At Extra High Voltage (EHV), prices are locational and the amount of credit that is applicable for an individual site will be derived individually. Generators will only be eligible for credits if they contribute to security of supply for a distribution network. The criteria used by DNO's to determine eligibility for credits at EHV effectively rules out intermittent[123] generation from receiving a credit. Where a non-intermittent EHV generator receives a credit, the credit will be a unit rate that applies to the super-red time band. The super-red timeband is normally a subset of the red timeband that applies at LV and HV but restricted to cover only the period of November to February. EHV generation do not receive a credit for any export outside of the super-red time period.

[123] Intermittent generation is defined as a generation plant where the energy source of the prime mover cannot be made available on demand, in accordance to the definitions in Engineering Recommendation P2/6.

For most generators, GDUoS credits are paid by the DNO to the generators supplier based on the metered export from the generation site. In a very small number of cases DNOs may interact directly with large generators connected to their network for the purpose of DUoS charging and credits[124].

Distribution losses

Distribution losses are applied to all metered volumes, including export units within each DNOs area to create boundary equivalent volume data at the transmission network that enters settlements. A supplier is able to offset the generation export data from their demand or, where the supplier has insufficient demand to offset the generation, will receive a credit for the metered export after it has been increased for distribution losses.

[124] This occurs where a generator is registered under Central Volume Allocation (CVA) rules and is effectively a separate Balancing Mechanism Unit. There are a handful of sites in each DNO area that meet this criteria.

Appendix 5 – Glossary

Term	Description
Active Network Management (ANM)	The active management of a network that enables a greater capacity of customers (either demand or generation) to connect that would, under some scenarios, exceed the capacity of that network.
Active Network Management Schemes (ANMS)	The use of ANM in a local area to allow demand and generation customers to connect while limiting reinforcement of the network
Ancillary services	Services procured by the system operator to help balance the electricity system
APX	An electronic market exchange platform that trades electricity futures
Assistance for Areas with High Distribution Costs (AAHDC)	A subsidy to assist customers in Scotland with the high cost of distributing electricity in that area
Balancing mechanism (BM)	A market-based mechanism that enables National Grid to instruct generators and suppliers to vary electricity production or consumption close to, or in real-time, in order to maintain safe operation of the system
Balancing Services Use of System (BSUoS)	Charges that are paid by electricity suppliers and transmission connected generators based on the energy taken from or supplied to the National Grid system in each half-hour settlement period. It varies for each settlement period
Balancing and Settlement Code (BSC)	Electricity industry code covering the rules for the Balancing Mechanism and the settlement of imbalance charges in GB
Balancing Mechanism Unit (BMU)	A subset of electricity generation or consumption that is registered to a supplier or generator under the terms of the BSC. A BM unit is typically the smallest available collection of meters with half-hour metering. On the generation side, it may be a single CCGT (combined cycle gas turbine) module or a genset (a powered electricity generator)
Biofuels/ biomass	In energy production, biomass refers to recently living biological material which can be used as a fuel. Normally biomass refers to plant matter grown for use as biofuel. Biomass does not add carbon dioxide to the atmosphere as it absorbs the same amount of carbon in growing as it releases when consumed as a fuel. It can be used to generate electricity with the same equipment or power plants that are used for fossil fuels.
Business as Usual (BAU)	The normal execution of standard functional operations within an organisation
Business, Energy and Industrial Strategy (BEIS)	The Department for Business, Energy and Industrial Strategy
Capacity	The amount of electrical power that can be generated from a unit
Capacity Market (CM)	An auction that is held each year to ensure there is sufficient generation capacity available on the system to meet demand
Capacity Market Supplier Charge (CMSC)	The charge levied on suppliers to recover the cost of running the capacity market

Term	Description
Carbon dioxide equivalent (CO2e)	A term used relating to climate change that accounts for the "basket" of greenhouse gases and their relative effect on climate change compared to carbon dioxide. For example, UK emissions are roughly 600 m tCO2e. This constitutes roughly 450m tCO2 and less than the 150m t remaining of more potent greenhouse gasses such as methane; which has 21 times more effect as a greenhouse gas, hence its contribution to CO2e will be 21 times its mass
Carbon footprint	The impact human activities have on the environment. This is measured by the amount of greenhouse gases (usually carbon dioxide) produced by a particular activity
CIBSE	Chartered Institution of Building Services Engineers
Climate Change Levy (CCL)	Government tax on the use of energy within industry, commerce and the public sector in order to encourage energy efficient schemes and use of renewable energy sources. CCL is part of the Government's Climate Change Programme (CCP)
Climate Change Programme	Introduced in 2000, the Climate Change Programme set out the Government's strategy at a sector-by-sector level for meeting national and international commitments to cut emissions of greenhouse gases. Now superseded by 2009's Low-carbon Transition Plan
Customer	Any person supplied or requiring to be supplied with gas or electricity at any premises in GB
Combined Heat & Power (CHP)	The use of a heat engine or power station to generate electricity and useful heat at the same time.
Combined Heat and Power Quality Assurance (CHPQA)	The CHP Quality Assurance programme (CHPQA) is a government initiative providing a practical, determinate method for assessing all types and sizes of Combined Heat & Power (CHP) schemes throughout the UK
Common Connection Charging Methodology (CCCM)	A standard methodology used by distributors to determine the charges for connecting to the distribution networks in GB as set down in DCUSA
Common Distribution Charging Methodology (CDCM)	A standard methodology used by distributors to determine the distribution use of system charges for Low Voltage and High Voltage customers in GB as set down in DCUSA
Connection and Use of System Code (CUSC)	The contractual framework for connection to, and use of, National Grid's transmission system and the transmission systems in Scotland
CMP	CUSC Modification Proposal
Controlled Market Entry (CME)	CME is the phased process that suppliers undertake to enable live trading with the national settlement systems
Corporate Social Responsibility (CSR)	Corporate social responsibility (CSR) is a business approach that contributes to sustainable development by delivering economic, social and environmental benefits for all stakeholders
Customer Relationship Management (CRM) system	Customer Relationship Management (CRM) is a system for managing a company's relationships and interactions with its customers and potential customers
Department of Energy and Climate Change (DECC)	DECC was formed in 2008 from the Energy Division of BERR and parts of DEFRA. Some references to BERR still exist and some energy related publications still reside on the BERR website, although the responsibility now resides with DECC. In 2016 DECC was absorbed into a new department labelled Department for Business, Energy and Industrial Strategy (BEIS)

Term	Description
Demand	The requirement for electrical power
Demand Side Response (DSR)	A scheme where customers are incentivised financially to lower or shift their electricity use at peak times
Direct Current (DC)	An electric current flowing in one direction only
Distribution connection and use of system agreement (DCUSA)	Established in October 2006 as a multi-party contract between licensed electricity distributors, suppliers and generators. It is concerned with connections to the distribution network and the use of the electricity distribution systems to transport electricity.
Distribution Losses	Power that is lost as electricity travels across the distribution network
Distribution Network Operator (DNO)	The operator of an electricity distribution network.
Distribution Use of System (DUoS)	Charges that are levied by host distribution companies to electricity supply companies to cover the cost of distributing electricity to their customers.
Domestic Customer	A customer where the property is used for residential purposes
DPD	Detailed Project Development
Electricity Market Reform (EMR)	Electricity Market Reform aims to deliver low carbon energy supplies whilst maintaining security of supply and minimising the cost to the consumer. This is achieved through two mechanisms; Contracts for Difference and the Capacity Market.
Electricity Market Reform (EMR) Delivery Body	The delivery body for EMR is National Grid
Embedded generation	Also called decentralised generation, decentralised energy or distributed energy. It is essentially when electricity is generated from energy sources connected to the distribution rather than transmission system
Energy Networks Association (ENA)	An industry body for the UK wires and pipes companies that carry electricity and gas to UK homes and businesses.
Energy supplier	The company supplying electricity, natural gas, fuel oil, kerosene, or LPG to a customer
Enhanced Frequency Response (EFR)	A service procured by National Grid that achieves 100% active power output at 1 second (or less) of registering a frequency deviation
ENWL	Electricity North West Limited
European Union (EU)	The European Union (EU) is a group of 28 countries that operates as a cohesive economic and political block
EU Emissions Trading Scheme (ETS/ EU ETS)	One of the policies introduced across Europe to reduce carbon emissions and combat the threat of climate change. The scheme runs in three-year phases and commenced on 1 January 2005.
Extra High Voltage (EHV)	Voltage levels greater than 11kV on a distribution network
Extra high voltage Distribution Charging Methodology (EDCM)	The national methodology used by distributors to set use of system charges for EHV customers as set down in DCUSA
Feed-in tariff (FiT)	A payment made to generators of small scale renewable electricity generation for electricity produced
Firm Frequency Response (FFR)	Firm Frequency Response (FFR) is the firm provision of dynamic or non-dynamic response to changes in frequency

Term	Description
Gas and Electricity Markets Authority (GEMA)	The main onshore gas and electricity regulator in Britain. GEMA is in effect the executive board of Ofgem
Gate closure	The point when bilateral trading stops and the balancing mechanism system is in operation. Currently set at one hour before the start of each trading period
General Block Exemption Regulation (GBER)	The General Block Exemption Regulation exempts EU member states from notifying the Commission of state aid, as long as all the GBER criteria are fulfilled
Gigawatt hour (GWh)	One million kilowatt hours
GLA	Greater London Authority
Grid Supply Point (GSP)	The point at which the transmission network meets the distribution network
Hedging	The process of making an investment to reduce the risk of adverse price movements in an asset. Normally a hedge consists of taking an offsetting position in a related security, such as a futures contract
High Voltage (HV)	Voltage levels between 1kV and 11kV (inclusive) on a distribution network
Higher Heating Value (HHV)	The higher heating value (also known gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C, which takes into account the latent heat of vaporization of water in the combustion products
Imbalance	The difference between the quantity of electricity delivered to/ taken from the electricity network and the contractual position of the supplier/ generator.
Kilowatt Hour (kWh)	A measure of electricity consumption. One Megawatt hour (MWh) equals 1,000 kWh, one Gigawatt hour (GWh) equals 1,000 MWh, and one Terawatt hour (TWh) equals 1,000 GWh
LA	Local Authority
Last In First Out (LIFO)	In the context of this document refers to the order in which generators are curtailed under a ANMS
Licence exemptible generation (LEG)	An electricity generator too small (<100MW) to be required to hold a generation licence
Licence-lite	Allows a small-scale electricity supplier to secure its own supply licence without requiring costly compliance with electricity codes, by contracting with a fully-licensed electricity supplier, who will comply with electricity codes on the licence-lite holder's behalf.
Low Carbon Contracts Company (LCCC)	LCCC was established to be the counterparty to Contracts for Difference (CFDs), the incentive designed by Government to bring forward the investment needed to sustainably deliver the UK's goals for renewable and other low carbon electricity
Low Voltage (LV)	Voltage levels lower than 1kV on a distribution network
Lower Heating Value (LHV)	The lower heating value (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C, which assumes the latent heat of vaporization of water in the reaction products is not recovered.
LPG	Liquefied petroleum gas

Term	Description
Market Economy Operator Principle (MEOP)	The Market Economy Operator Principle (MEOP) is a concept which has been developed by the Commission to determine whether a transaction entered into by a public body gives an advantage to a particular economic undertaking and therefore falls within the State aid regime
Master Registration Agreement (MRA)	The Master Registration Agreement (MRA) is an industry-wide agreement that provides a governance mechanism to manage the processes established between electricity suppliers and distribution companies to enable electricity suppliers to transfer customers
Megawatt (MW)	Standard measure of generation plant capacity equal to one thousand kilowatts, or one million watts. Medium to large power stations have capacity typically in the range of 500MW to 2,000MW
Meter reading	Used to determine energy consumption and for issuing a bill for energy usage for a given period.
N2EX	An electronic market exchange platform that trades electricity futures, including a day-ahead auction
Netting Off Agreement (NOA)	The agreement between two parties where the anticipated imbalance position of a market participant is procured on their behalf by the other counterparty.
Non-domestic customer	A customer who is not a domestic customer
Non-Fossil Purchasing Agency Limited (NFPA)	Non-Fossil Purchasing Agency Limited (NFPA) is involved in the administration of generation contracts awarded under the Non-Fossil Fuel Orders
NPG	Northern Power Grid
Ofgem	The Office of Gas and Electricity Markets
Open Cycle Gas Turbine	An open cycle gas turbine is a combustion turbine plant fired by liquid fuel to turn a generator rotor that produces electricity
Over-the-counter (OTC)	Trading where financial instruments such as stocks, bonds, commodities or derivatives may be traded directly between two parties. It is the opposite of exchange trading which occurs on futures exchanges or stock exchanges. An OTC contract is a bilateral contract in which two parties agree on how a particular trade or agreement is to be settled in the future
Photo Voltaic (PV)	A term which covers the conversion of light into electricity using semiconducting materials
Power Purchase Agreement (PPA)	An agreement between a supplier and generator to purchase the export from the generator that flows onto the public network
Renewables Obligation (RO)	The Government’s main policy measure to encourage the development of electricity generating capacity using renewable sources of energy in the UK. This scheme was closed in April 2017.
Renewables Obligation Certificate (Roc)	Certificate issued by the regulator to generators who demonstrate that they have issued one MWh or renewable electricity
Renewable Heat Initiative (RHI)	The Renewable Heat Incentive (the RHI) is a payment system in England, Scotland and Wales, for the generation of heat from renewable energy sources
Residual Cashflow Reallocation Cashflow (RCRC)	RCRC charges arise from balancing the residual cashflow within the balancing mechanism once all payments to or from participants within a half hour have been made

Term	Description
Services of General Economic Interest (SGEI)	Services of general economic interest (SGEI) are economic activities that public authorities identify as being of particular importance to citizens and that would not be supplied (or would be supplied under different conditions) if there were no public intervention
Short-Term Operating Reserve (STOR)	STOR is a contracted balancing service whereby the Service Provider delivers a contracted level of power (within pre-agreed parameters) when instructed by National Grid
Significant Code Review (SCR)	The Significant Code Review (SCR) mechanism is designed to facilitate complex and significant changes to industry codes that energy companies are required to abide by. It enables Ofgem to undertake a review of a code-based issue and play a leading role in facilitating code changes through a review process.
SLC	Standard Licence Condition.
Smart meter	A system installed for the purposes of the supply of electricity which, as a minimum: consists of an electricity meter and any associated or ancillary devices identified in; has the functional capability specified by; and complies with the other requirements of, the SME Technical Specification applicable at that date.
SME	Small or medium-sized enterprises
Special Purpose Vehicle (SPV)	A legal entity created solely to serve a particular function
SPEN	Scottish Power Energy Networks
SSEPD	Scottish and Southern Energy Power Distribution
Standard Variable Tariff (SVT)	A 'standard variable' rate tariff is the default tariff for a customer that has not chosen a specific energy plan
Supplier	A party licensed by Ofgem to sell power to end-users
Supplier in a box	The term used to describe the procurement of a prequalified electricity supply licensed company from a specialist utility IT systems vendor that has gained an electricity supply licence and acceded to a number of the core industry codes.
Supplier Services Agreement (SSA)	The agreement between a Licence Lite supplier and the Senior supplier
System Imbalance Price (SIP)	The price paid by or to parties who are out of balance within the national settlement system within each half hour
System operator (SO)	The body that manages the operation of the system from day-to-day; part of National Grid's role in GB for gas and power
Targeted Charging Review (TCR)	A consultation document issued by Ofgem in March 2017 regarding their proposal to undertake a Significant Code Review of certain areas of network charging
Transmission Losses	Power that is lost as electricity travels across the transmission network
Transmission Network Use of System (TNUoS)	Charges that are paid to National Grid by those generators and suppliers who are considered to have used the electricity transmission network to transport energy. The charges vary for both generators and suppliers according to their geographic location and the demand for grid usage at that location

Term	Description
Treaty on the Functioning of the European Union (TFEU)	The Treaty on the Functioning of the European Union (2007) is one of two primary Treaties of the European Union, alongside the Treaty on European Union (TEU). Originating as the Treaty of Rome, the TFEU forms the detailed basis of EU law, by setting out the scope of the EU's authority to legislate and the principles of law in those areas where EU law operates
UKPN	UK Power Networks
Vertical Integration	Vertical integration is where a company acquires several parts of the supply chain, normally to diversify the revenue risk associated with supplying customers
WPD	Western Power Distribution