

A GUIDE TO TRANSMISSION AND DISTRIBUTION IN SCOTLAND

**PREPARED FOR
THE SCOTTISH GOVERNMENT &
HIGHLANDS AND ISLANDS ENTERPRISE**



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ISSUED 31 MAY 2010

REP 1114/005/001C

REPORT VERSION HISTORY

V	Author(s)	Verifier	Approver	Date	Notes
A	C Menzel N C Scott M R Smeed H M Snodin	N C Scott H M Snodin	H M Snodin	01/12/2009	First issue for comment
B	M R Smeed H M Snodin	H M Snodin	H M Snodin	09/03/2010	Second issue for publication
C	H M Snodin	C Menzel	H M Snodin	31/05/2010	Minor updates for publication

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GLOSSARY

Acronym	Full Term	Acronym	Full Term
B1	Boundary 1 (northwest Scotland)	kW	Kilowatt
B6	Boundary 6 (Cheviot Boundary)	LTDS	Long Term Development Statement
BEGA	Bilateral Embedded Generation Agreement	LV	Low Voltage
BELLA	Bilateral embedded Licence exemptible Large power station Agreement	MW	Megawatt
BETTA	British Electricity Trading and Transmission Arrangements	MWh	Megawatt hour
BSC	Balancing and Settlement Code	NETA	New Electricity Trading Arrangements
BSP	Bulk Supply Point	NGET	National Grid Electricity Transmission Plc
BSUoS	Balancing Services Use of System charges	Ofgem	Office of the Gas and Electricity Markets
CUSC	Connection and Use of System Code	OFTO	Offshore Transmission Owner
DECC	Department for Energy and Climate Change	RPZ	Registered Power Zone
DCUSA	Distribution and Connection Use of System Agreement	SG	Scottish Government
DNO	Distribution Network Operator	SPD	ScottishPower Distribution
DPCR	Distribution Price Control Review	SPT	ScottishPower Transmission
ENSG	Energy Networks Strategy Group	SHEPD	Scottish Hydro Electric Power Distribution
EU	European Union	SHETL	Scottish Hydro Electric Transmission
FIT	Feed in Tariff	SQSS	Security and Quality of Supply Standard
FSL	Final Sums Liability	SSE	Scottish and Southern Energy
GB	Great Britain	SO	System Operator
GDUoS	Generator Distribution Use of System	STC	System Operator Transmission Owner Code
GSP	Grid Supply Point	SYS	Seven Year Statement
GW	Gigawatt (1000MW)	TAR	Transmission Access Review
GWh	Gigawatt hour	TNUoS	Transmission Network Use of System charge
HIE	Highlands and Islands Enterprise	TO	Transmission Owner
HVDC	High Voltage Direct Current	TPCR	Transmission Price Control Review
IGUC	Interim Generic User Commitment	UK	United Kingdom
ITT	Invitation to Tender	VAT	Value added tax
km	Kilometre	XE	Xero Energy
kV	Kilovolt		

1 Introduction

1.1 General

Xero Energy (XE) Ltd has been commissioned jointly by The Scottish Government (SG) and Highlands and Islands Enterprise (HIE) to provide an overview of the current transmission and distribution landscape in Scotland. This guide includes a brief discussion regarding technology and physical assets as well as information on key aspects of the industry including basic definitions, major players, regulatory and commercial frameworks and connection processes. XE also has included a brief look forward to some potential developments on the horizon.

1.2 Purpose of guide

The purpose of this guide is to cover the basics of transmission and distribution and to inform HIE and SG on the context in which regulatory change can have a material impact on projects on the ground. It will also help identify key sectors and players to guide those wishing to influence this important agenda.

1.3 Intended readership

This guide has been designed to provide an introduction to transmission and distribution in Scotland and should therefore be accessible to a non-specialist readership.

1.4 Areas not covered in the guide

This high level guide focuses on the generation and transportation of electricity within Scotland and Great Britain (GB). Issues relating to demand and end consumers are not discussed at length but are mentioned as part of the commercial framework for electricity markets.

1.5 Structure of the guide

The guide has been structured into the following sections:

Section 1	Introduction – general introduction and definitions
Section 2	Transmission and distribution basics – the fundamentals
Section 3	Industry overview – the key players
Section 4	Commercial and regulatory frameworks – key governing policies
Section 5	Connection process – how a new connection is made and its costs
Section 6	Connection issues in Scotland – current grid issues in Scotland
Section 7	Access and charging – terms for customers to use the grid
Section 8	Looking forward – changes likely in the medium to long term
Section 9	Summary
Section 10	References

2 Transmission and distribution basics

2.1 Introduction

This section sets out the basics that define transmission and distribution and sets this in a Scottish context. The Scottish generation mix is also discussed briefly with some reference to the grid and Scotland as a net exporter of electricity.

2.2 Voltage levels – transmission

The voltage level that a power line (circuit) operates at depends on the purpose of that circuit. High voltage electricity ‘highways’ are used for bulk transport of power. In Scotland these ‘routes’ are rated at 132,000 Volts (or 132 kilo Volts, kV), 275kV or 400kV and are classed as transmission assets [1]. Generally these lines are used for transferring power between areas of dense population and from large power stations like Cnockenzie coal power station (connected at 275kV) or Torness nuclear power station (connected at 400kV). In Scotland, many hydro power stations and large wind farms are connected at 132kV [2].

Transmission at high voltage can be thought of as a high speed link with low losses along the way, and as such is the most economical option for long distance transport. Figure 2.1 illustrates that there is a relationship between voltage and the look and size of the supporting infrastructure required to carry the wires overhead.



Figure 2-1: Example of a 275kV, a 132kV and 33kV line (left to right)

As can be seen in the figure, the higher the voltage the greater the clearance from the ground. Undergrounding is typically more expensive, and generally causes more disturbance (i.e. the trench is wider) the higher the voltage.

2.3 Voltage levels – distribution

For supplying towns and communities, lower voltages are used – in Scotland this is generally done at 33kV and 11kV. These kind of circuits are analogous to A and B roads and are often run on wood pole structures (an example of which can be seen in Figure 2-2), or run underground.



Figure 2-2: An example of a 33kV wood pole structure with cable terminations and 33kV to LV pole mounted transformer

Transformers transform voltages up and down. It is normal to see transformers situated at the ends of streets or even mounted on individual wood poles outside dwellings (the small grey cylinder in Figure 2-2 is an example of a pole mounted transformer) in order to step down the voltage from 11kV (and 33kV) ready to be supplied to domestic and/or commercial properties as a Low Voltage (LV) supply.

At the domestic level, electricity is supplied at 415/230V, and this and all other voltages below 1,000V are known as LV. At LV the energy losses can be significant, up to around 7% of all power that is exported through this kind of system [3] so LV grids tend to be very localised.

2.4 System delineation

In Scotland, transmission is defined as any electrical asset that is operating at or above 132kV, while distribution refers to any asset operating below this. This varies from the situation in England and Wales, where onshore distribution assets are 132kV and below, while transmission assets are mainly restricted to 275kV and 400kV. This is largely reflective of the low level of a demand in particularly rural and remote nature of much of Scotland.

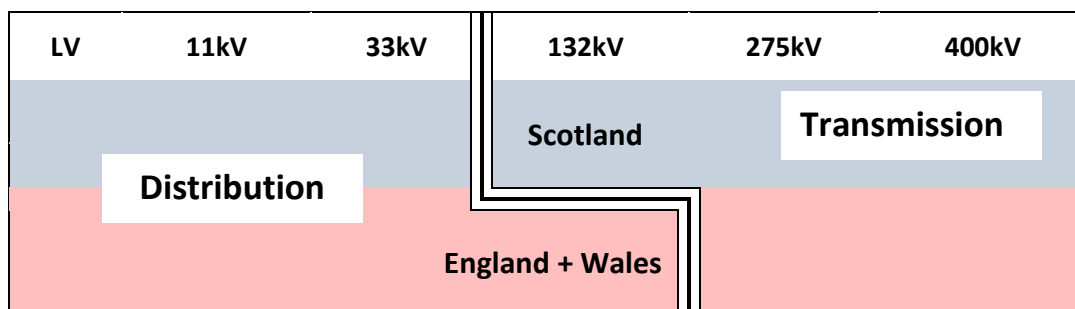


Figure 2-3: Illustration of the split between onshore transmission and distribution in GB

The points where the transmission system and the distribution system are connected are denoted as Grid Supply Points (GSP) if it is a point of supply of electricity from the transmission system to distribution or large transmission-connected customers, or as Grid Entry Points (GEP) if it is a point of entry onto the transmission system for a generator [4].

2.5 Privatisation and business separation

From 1990 onwards the monopoly state-owned electricity boards have been broken up and sold off (privatised). Regulatory arrangements have been put in place to: protect consumers and other customers from exploitation where there remain some natural monopolies – most notably operation and maintenance of the main electricity networks are still generally monopoly businesses; and to promote competition as a means of regulating prices in competitive areas of the electricity industry – generally this is generation and billing (supply) of electricity. The regulator is the Office for Gas and Electricity Markets (Ofgem).

Transmission and distribution functions are run by separate businesses. At transmission there is also now a separation between the function of operating the transmission system and the functions of owning, maintaining and planning the transmission system. Therefore at transmission the assets are owned by a Transmission Owner (TO) and operated by the System Operator (SO). At distribution the assets are typically owned and operated by one company, known as a Distribution Network Operator (DNO). The transmission and distribution companies in Scotland are discussed in Section 3.

The transmission and distribution networks each have their own set of rules that govern what can be connected, what technical standards (e.g. Grid Code or Distribution Code) need to be met and the commercial frameworks the users of these systems must operate under.

Finally it is worth noting that there is an electricity market operator function run by a company called Elexon. Its purpose is to register and settle the contractual agreements for generation and supply of electricity, on a half-hour by half-hour basis.

2.6 Demand for electricity

Electricity generation and demand is measured in units of Watts and of Watt hours. A Watt, or kilo Watt (kW) or Mega Watt (MW) is a measure of the instantaneous power, and a Watt hour or more often kilo or Mega-Watt hour (MWh) is the product of the instantaneous power output and the period of measurement. The Watts are like the settings on a cooker which can be set for the desired temperature, and the energy consumed by the cooker is a function of the setting and the time for which it is on.

So, if energy numbers are quoted as a function of time, then it is a measure of the energy consumed over time – annual consumption for instance. If they are quoted as a power number on its own, then it is a snapshot in time – peak demand or maximum demand or the rated (maximum) capacity of a generator.

Currently, the annual demand for electricity in Scotland sits at around 40,922 Giga Watt hours (GWh) every year [5], with the maximum or peak demand for electricity is about 6 GW. The current level of installed generation in Scotland is around 11 GW. This means that at the time of writing, installed capacity exceeds peak demand by around 5GW. Looking at Scotland in isolation, this 5GW could be seen as the plant margin (which is usually expressed a percentage of peak demand, in this case 83%). However Scotland is operated as part of a Great Britain-wide network and demand from England is therefore also relevant – that is, the System Operator relies on generation in Scotland being available to meet demand in England.

There is always a need to have some excess of generation over peak demand, because not all generation is available all of the time. Generation plant takes maintenance outages, can suffer technical faults, there could be problems with fuel supplies or, in the case of variable renewable resources the ‘fuel’ is not available all of the time. The correct relationship between installed capacity and demand is very much dependent on the generation mix and system characteristics. As renewables increase, this relationship is changing – the focus is gradually moving away from installed capacity and more onto probabilistic analysis of resource-dependent energy output.

Scotland has for a long time exported excess electricity to England and latterly to Northern Ireland. The general trend is for Scotland to continue, and potentially, expand, its net exports of electricity. This is driven primarily by expectations of new renewables plant in Scotland, but also by some less concrete plans to replace ageing thermal capacity.

2.7 Generation mix

In 2008 (the most recent available data), Scotland generated 49,911GWh of electricity from a reasonably diverse generation mix [5]. Around 26% of the installed capacity is renewable technology (mainly hydro and wind), 7% of pumped storage, about 21% is nuclear-powered and 47% is fossil fuel generating plant (coal and gas including CHP) [6] [7]. However, the actual energy that is supplied from these generators is not necessarily in proportion to the installed MW capacity, i.e. in 2008 nuclear power met much (approximately 30%) of the energy demand (MWh) in Scotland while renewable generation represented a smaller energy percentage at around 18% [5]. As a percentage of annual consumption, renewables supplied approximately 22% of the demand for electricity in Scotland in 2008 [5], as 8,989GWh (18.0% of total generated) was exported to England, Wales and Northern Ireland.

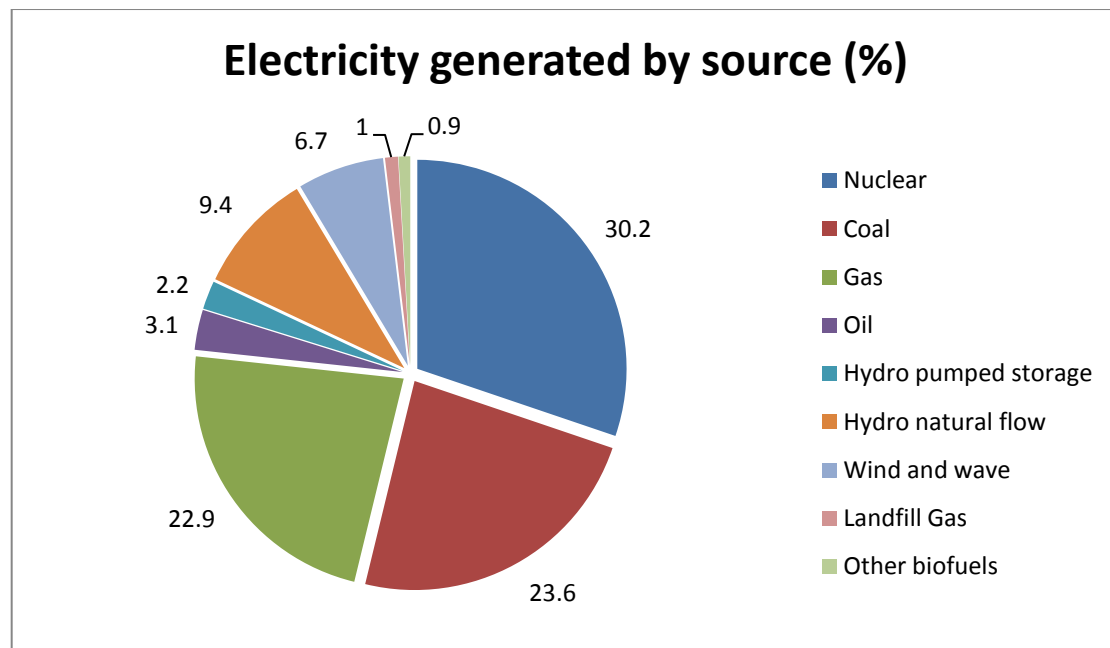


Figure 2-4: Percentage of electricity generated in Scotland by fuel source [5]

2.8 Interconnection to England, Wales and Northern Ireland

At time of writing there are two double transmission circuits to England from Scotland. These have been known as the 'interconnector' circuits but in recent times, 'the Cheviot Boundary' or B6 has been used to describe them. They are rated at some 2.2 GW firm capacity, but are being upgraded to some 3.3 GW firm capacity by 2012/13 [8]. Further uprating to around 4 GW is expected. The limitations on transfer capability are driven by both thermal ratings (the amount of current that can be carried without the lines overheating) and system stability issues (to do with voltage and other system characteristics).

As discussed in the section above, the existing, planned and potential generation in Scotland is more than is required to supply Scotland's demand. This makes Scotland a net exporter of electricity both now and for the foreseeable future, primarily across the Cheviot Boundary circuits to England. This boundary therefore presents a serious constraint on power export from Scottish generators. The issues surrounding these power flows and further potential reinforcements are discussed in section 6.2 and 8.3 respectively.

In addition to the transfer capability to England there is a 500MW interconnector from Southern Scotland to Northern Ireland. This link is generally exporting from Scotland to Northern Ireland and currently has a commercial export limit of up to 450MW of power into the Northern Irish grid. However, due to constraints on entry capacity there is only 80MW of import capacity from Northern Ireland back into Scotland [9].

2.9 Asset landscape

2.9.1 Introduction

In order to understand the existing grid more clearly, this section presents a high level discussion of the existing physical assets that currently make up the transmission and distribution systems in Scotland.

2.9.2 Transmission assets

An overview of the transmission assets that currently exist in Scotland is given in Figure 2-5.

From the south, there are two 400kV (blue) circuits extending up from England, a double circuit on the east coast and one further west. These circuits reach up through the central belt.

North of the central belt there are currently no 400kV assets, with only two 275kV double circuits running along the east coast towards Dundee, Aberdeen and Peterhead. One 275kV double circuit then runs west from Blackhillock to Beaulay (near Inverness).

From Beaulay there is a transmission loop north to Dounreay, currently consisting of a single 275kV circuit and a 132kV (black) double circuit.

From Beaulay back down to Denny (near Stirling) there is currently one double circuit 132kV link. This line has received planning approval for upgrading to a 400kV double circuit, and is due for completion by 2013 at the very earliest.

There is a single 132kV circuit that radiates from Fort Augustus (on the Beaulay – Denny line) that serves Skye and the Western Isles. This line also tees off and forms part of a double circuit 132kV connection down to Fort William.

To the northwest of Glasgow, there is a 275kV double circuit running up to Cruachan hydro power station as well as a 132kV double circuit that extends from Glasgow up to Sloy and round the coast to Carradale on the Kintyre peninsula.

Currently, there is no transmission system on Orkney or Shetland but the potential for these being developed is discussed in Section 8.

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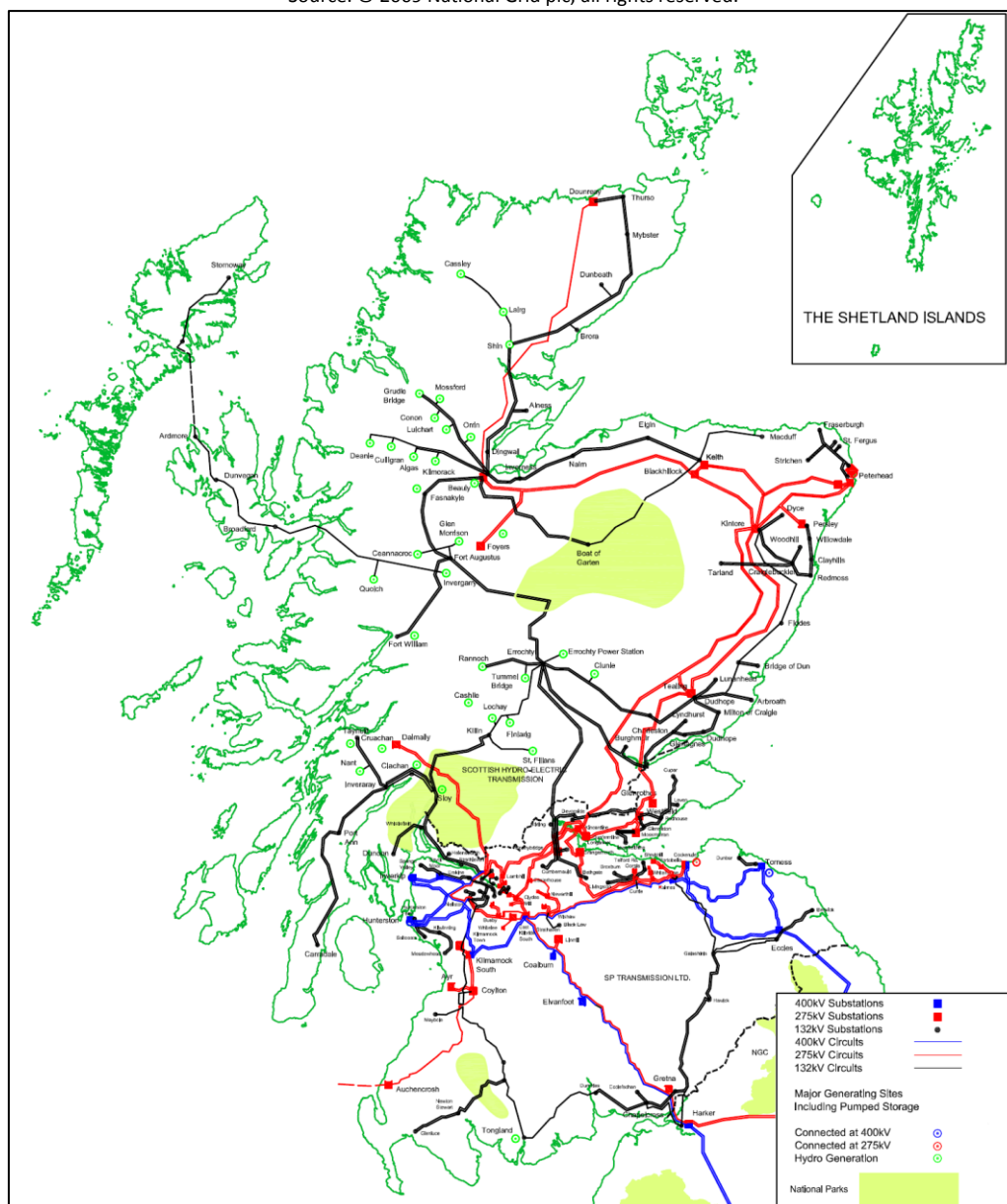


Figure 2-5: Map of existing transmission system in Scotland (2009) [2]

2.9.3 Distribution assets

The distribution system in Scotland constitutes a significant amount of 11kV and 33kV assets spread over most of the country. As noted above the transmission system does not reach many areas of Scotland and hence the distribution system is quite expansive.

Unlike transmission, distribution assets have been taken out to most of the islands around the west and north coasts. However, the vast majority of these lines are very limited in their capacity to accept generation projects due to low power ratings and voltage issues.

There are some significant 33kV assets that are worth mentioning; specifically the two 33kV circuits that link Orkney to the mainland. These circuits are fed from the transmission system at Thurso and go subsea across to Orkney and land on Hoy. Orkney is a renewable resource rich area with lots of scope for developing renewable technology. Because of this

there is a very high level of utilisation of these 33kV links to the mainland. In order to facilitate this high utilisation the islands are operated under a Registered Power Zone (RPZ) scheme which is discussed in more detail in section 7.2.2.

The distribution system on Shetland is also worth mentioning as it is not yet connected to the mainland grid at all. The islanded grid is maintained at 33kV and 11kV via three generator stations (gas, diesel and wind) as well as voltage control and reactive compensation equipment, located at various parts of the circuits. There is a new wind power development (Viking Energy) currently in planning that would trigger a High Voltage Direct Current (HVDC) transmission link between Shetland and the Scottish mainland [10].

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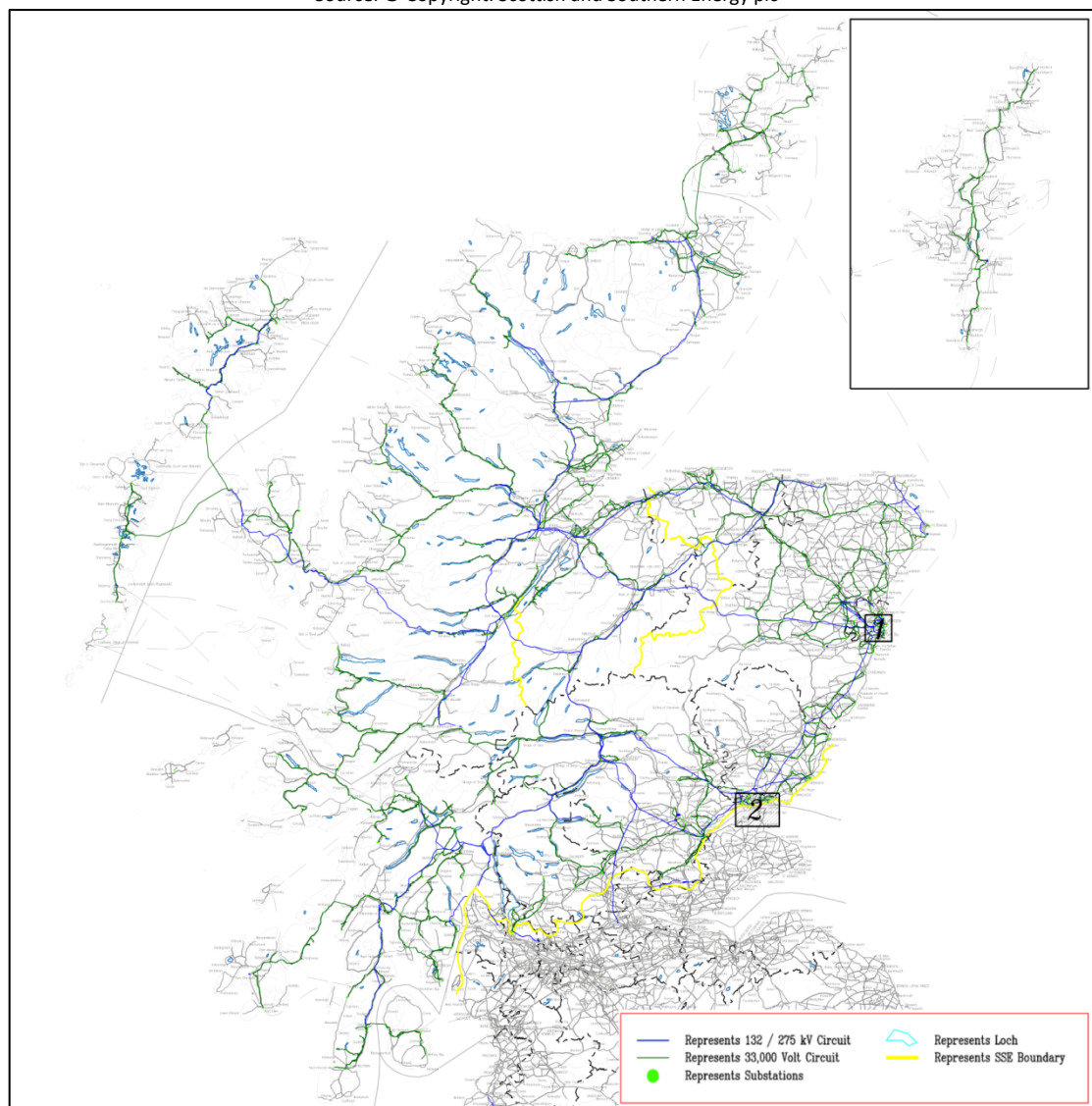


Figure 2-6: The existing (2008/09) transmission & distribution system in the north of Scotland [11]

3 Industry overview

3.1 Introduction

The following section introduces the major players that operate in the electricity industry in Scotland. Figure 3-1 gives a high level overview of the market as well as an indication (necessarily simplified) of how these parties are related, electrically and commercially.

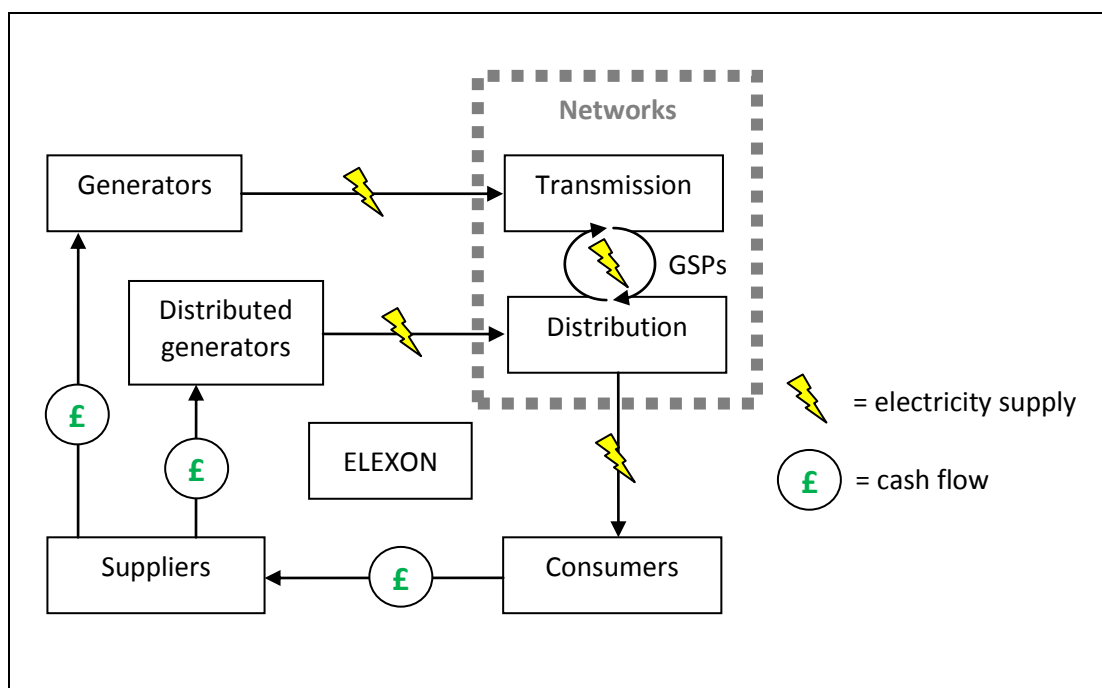


Figure 3-1: High level representation of the electricity market

3.2 The Regulator - Ofgem

The regulator is an independent body at so-called ‘arms length’ from government, and is called the Office for Gas and Electricity Markets (Ofgem). Ofgem’s primary objective is to protect the interests of electricity consumers. This objective has recently been formalised as an obligation to consider future as well as current consumers, which basically gives Ofgem a greener agenda. Both the government and Ofgem place a strong emphasis on the role of competition in markets to keep prices at a justifiable level.

The “Authority” is Ofgem’s governing Board which oversees the organisation and makes key decisions.

Ofgem has a very major role in determining what the monopoly network companies can do, and how much they earn. It regulates the network companies “through five-year price control periods which include curbs on expenditure as well incentives to be efficient and to innovate technically” [12]. Price control reviews are discussed briefly in Section 4. Any investment that TOs or DNOs wish to pass through to consumers must be sanctioned by Ofgem and any changes in transmission or distribution policy require approval of (and can often be triggered by) Ofgem. Ofgem must also make sure that the companies remain sound so that they can carry on their essential activities. This tends towards them being relatively low risk-taking companies for the core part of their business.

3.3 Government

Government is a key player in determining the framework in which industry operates. Normally this is through legislation, which is described in more detail in Section 4. Occasionally government will become more involved in detailed market rules, but this is atypical. For instance the Department for Energy and Climate Change (DECC) recently intervened in transmission access rules and is in the process of legislating for some changes to access rules.

More typical for both DECC and the Scottish Government is to facilitate industry discussion on key themes, gather evidence and legislate where necessary.

3.4 National Grid

National Grid is licensed by Ofgem to be the System Operator for Great Britain, the GBSO. As GBSO, National Grid is responsible for balancing generation and demand across the transmission system minute by minute [13].

Across GB National Grid is also responsible for setting and maintaining transmission charging methodologies, and for setting the contractual terms for using the transmission system.

The charging methodologies serve to apportion out the costs of operating and maintaining the transmission system. These methodologies set what users pay to connect to and use the transmission system.

All transmission users across GB must sign contracts with National Grid. This means that in Scotland generators wishing to connect to the transmission system need to make an application to National Grid, even though National Grid does not own transmission assets in Scotland (Scottish Power and Scottish and Southern Energy own the assets in South and North Scotland respectively – see below). National Grid will liaise with the relevant Scottish TO when preparing a connection offer in Scotland. The Scottish TOs will also speak to customers about transmission connections, but they are not the contractual party for users.

National Grid is also the licensed onshore Transmission Owner (TO) for England and Wales. It's SO and TO roles are run and regulated as separate businesses.

3.5 Market Operator - Elexon

Financial reconciliation and settlement of electricity contracts for purchase and sale of electricity is undertaken by the Market Operator, a company named Elexon. This company administers the Balancing and Settlement Code (BSC) to which all major generators and suppliers must adhere.

Market participants notify their contractual positions to Elexon in advance of real time, and, for each half hour period, this is reconciled against actual metered positions (or, for non-half-hourly metered customers such as most domestic demand, positions are settled based on agreed profiles of consumption).

3.6 Scottish Transmission Owners (TOs)

The transmission system in Scotland (operating at 132kV and above) is owned by two companies, Scottish Hydro Electricity Transmission Ltd (SHETL) in the north, and Scottish Power Transmission (SPT) in the south.

3.6.1 Scottish Hydro Electricity Transmission Ltd (SHETL)

SHETL owns all of the transmission assets in the north of Scotland, whose ownership boundary (shown by the dotted black line in Figure 2-5) runs from the west coast (south of Sloy) along the north edge of the central belt and the Firth of Forth to the east coast at the Firth of Tay [2].

SHETL is a subsidiary of Scottish and Southern Energy (SSE) which also owns two DNO companies, one in the north of Scotland and one on the south coast of England. SSE has a number of other commercial interests including power generation and electricity supply. As mentioned previously the electricity market is regulated, and the monopoly interests of transmission and distribution operate with business separation from each other and from other parts of SSE's business.

3.6.2 Scottish Power Transmission (SPT)

SPT owns the transmission assets that are located south of the border with SHETL and north of the English border. Unlike SHETL, SPT's asset base already includes 400kV transmission lines.

Similar to SSE, Scottish Power Ltd (and its parent company, Iberdrola) is a group with many commercial aspects, including electricity transmission, distribution, supply and generation. Again, similar to NGET and SSE, the network businesses operate with strict business separation.

3.7 Scottish Distribution Network Operators (DNOs)

GB is split into 14 regions that are controlled by different DNO companies. These companies have a license to distribute electricity. In Scotland there are two DNOs, Scottish Hydro Electric Power Distribution (SHEPD) in the north and Scottish Power Distribution (SPD) in the south, separated along the same ownership boundary as the transmission system.

3.7.1 Scottish Hydro Electric Power Distribution (SHEPD)

As with transmission, a subsidiary of SSE also operates the distribution network in the north of Scotland under the company name SHEPD. This area consists mostly of rural networks, but does include Perth, Dundee, Aberdeen and Inverness. Also included in this area are all of the Hebrides, Orkney and Shetland.

Voltage level	Line length (km)	
	Overhead line	Underground cable
11kV	21,726	4,799
33kV	5,397	1,174
LV	4,125	9,240

Table 3-1: composition of SHEPD's network [11]

3.7.2 Scottish Power Distribution (SPD)

Similar to the transmission system, SPD operates the distribution system south of the boundary with SHEPD and north of the English border. This area includes Glasgow, Stirling, Edinburgh and Dumfries serving two million customers [14]. Table 3-2 below gives an outline of the composition of SPD's network.

Voltage level	Line length (km)	
	Overhead line	Underground cable
11kV	14,300	12,316
33kV	2,687	2,912

Table 3-2: composition of SPD's network [14]

3.8 Other industry players and industry relationships

The previous sections have described the key industry and governing bodies involved in the provision of grid networks. Generators and suppliers are often collectively referred to as "users" of the grid networks. It is important to bear in mind that the commercial environment for users and the grid providers is very different, and this can be a defining feature of relationships with each other and with the Regulator.

Generators and suppliers each operate in a competitive market environment. Generators compete with each other for electricity sales, and perhaps more so for grid access because it is so scarce. Suppliers compete with each other for electricity customers. Generators and suppliers need to adhere to market rules, and the larger licensed generators and suppliers have licence conditions stipulated by Ofgem. The regulatory environment for generators and suppliers is designed on the basis that competition will regulate prices – that is, they are generally not regulated on how much they can earn.

In contrast, monopoly providers of grid services are regulated closely on allowed revenues. This is because there is limited or no competition for the services. This also means as noted that the companies can be quite risk averse, and often need regulatory approval for spend over-and-above that anticipated in five-yearly price reviews.

3.9 Network users

3.9.1 Demand customers

In the main, demand for electricity comes from consumers, connected at low voltage to the distribution system. Even most industrial demand customers are connected at distribution voltages. From the perspective of the transmission system, all of these demand customers are aggregated together under GSPs (at the interface between transmission and distribution) [2]. There are however some demand customers connected directly to the transmission system such as very large industrial plant.

3.9.2 Generation customers

In Scotland there is a wide range of generation customers connected to both the transmission and distribution systems. Connections to the transmission system include both nuclear stations (connected at 400kV) and large thermal generating stations, connected at 275kV or 400kV. There are also a number of larger hydro and pumped storage facilities (e.g. Cruachan at 275kV) and a few wind power (e.g. Crystal Rig 2 at 400kV) projects connected to the transmission system. However most of the transmission connected wind and hydro projects are connected at 132kV [2]. Over the coming years, there are a number of offshore wind generation projects which will also connect to offshore transmission infrastructure (132kV or above). Offshore transmission is discussed in more detail in sections 4.5 and 5.6.

Mainly due to the economics of establishing a grid connection at transmission voltage levels as well as the scarcity of assets in Scotland, most smaller generation projects connect at distribution; these projects are termed embedded (or distributed) generators. Embedded and distributed are used synonymously for generators connected to the distribution system.

There are technical limitations to the amount of generation that can be connected to a single point at each voltage level. An outline of the realistic size of generation project that can be connected at each voltage level (despite any issues) can be seen in Table 3-3 below.

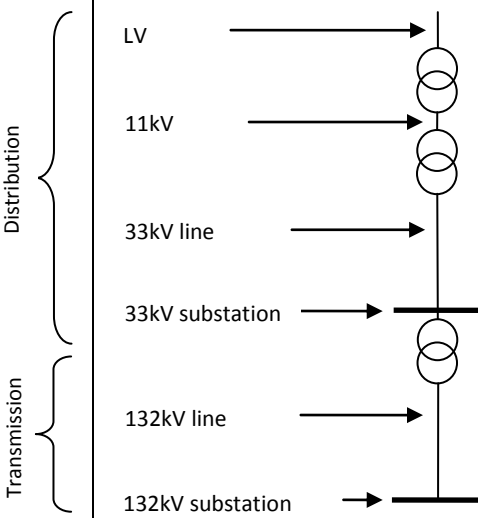

	Voltage level	Connectable generation capacity
Distribution	LV	a few kW
	11kV	A few MW, possibly more close up to the supply substation
	33kV line	10 – 30MW
	33kV substation	up to the rating of the transformers – perhaps 60MW or more
Transmission	132kV line	50 – 100MW
	132kV substation	100MW plus
		

Table 3-3: Connectable capacity for generators

4 Commercial and regulatory frameworks

4.1 Introduction

The regulatory framework is shaped by a number of legal instruments, including relevant European Directives, UK Acts, licences, industry codes and technical standards. The Scottish Government has no formal powers in electricity sector regulation, but it does have responsibilities in closely related areas of renewable energy, energy efficiency, fuel poverty, climate change and planning, amongst others. It has also recently published a “National Conversation” paper on Scotland’s future role and relationships in energy matters [15].

The regulatory environment has a major impact on the commercial environment for market participants, and because of this many parties monitor and influence the market arrangements, as well as decisions by the Regulator and evolution of legislation. Influence is brought to bear through participation in the governance arrangements for industry codes, various industry fora and through responding to formal consultations.

The regulatory landscape is typically in flux. It is an extremely resource-intensive activity to keep abreast of developments, even more so to actively participate, and this tends to put a limit on what many players can do in this area. Most large companies will have staff working full time on regulation whereas smaller companies need to rely on representation via trade associations and interest groups. There are recent moves to make some of the more specialist code governance processes more accessible in cost and complexity terms for wider participation. This is via Ofgem’s Code Governance Review [16].

The remainder of this Section provides a summary of the main tiers of regulation pertaining to electricity networks, and the relationship to the commercial arena.

4.2 European legislation

The higher up and wider scope of the legislation, the more principles-based and scene-setting (rather than circumstance-specific) it tends to be. Therefore, as a rule, European legislation will typically guide Member States on the high level principles they must follow. It can be very important driver for change at the Member State level.

There is a substantial amount of European legislation on promoting trade in energy markets, climate change and renewable energy. Perhaps the most-quoted piece of European legislation for renewables and network access is the Renewables Directive. The Directive has recently been updated and re-issued (Directive 2009/28/EC on the promotion of the use of energy from renewable sources). It sets renewables supply targets and gives principles on how renewables should be treated when seeking access to the transmission system and how they should be charged – this majors on making sure that projects can get access on fair terms and that they are not discriminated against. It also asks Member States to take steps to develop their transmission and distribution grid infrastructure, and to promote interconnection of networks and intelligent networks needed to access renewable energy sources.

Influencing European policy is for those with an eye on a long-term end game. It is a very political arena which can be slow to change but with the resulting change being relatively long-lasting.

4.3 UK legislation

The primary piece of legislation for the electricity industry is the Electricity Act 1989. It defines principle objectives and general duties of the Regulator as well as granting and modification processes of licenses to transmit, distribute, generate and supply electricity in the UK. There have been other instruments since which amend and supplement the Electricity Act. Over time this has refined the primary objectives for the Regulator which has quite a significant bearing on what it must take into account when making decisions.

There is also a significant amount of so-called secondary legislation which puts meat to the bones of some of the enabling powers in energy primary legislation.

The UK government often consults on the principles of new legislation and, for those with a more legal perspective there is also typically a chance to comment on the wording of draft legislation. Many important refinements are however undertaken during the passage of legislation through Parliament, and it is usually only political lobbyists that manage to influence policy at this stage.

4.4 GB-wide electricity market arrangements

Since April 2005, there has been a GB-wide electricity market, which, very basically, involved creating common GB-wide arrangements for transmission system operation, transmission charging, commercial and technical arrangements for connection to and use of the transmission system and financial settlement of electricity purchases and sales. These arrangements are all set out in legal and technical documents in what are termed “industry codes.”

Parties can variously propose changes to these codes, each of which has change management processes. The “code administrators” oversee a constant stream of these changes – some substantial and commercially significant, some more housekeeping-type changes. If you are a party to the code in question, there is usually the chance to participate in a Working Group or industry forum to debate and develop code changes. A code panel is responsible for directing the code changes and Ofgem usually has the final say on whether a change is approved or not.

Some of the key industry documents are listed in Appendix C.

4.4.1 Commercial access and charging rules

The rules which shape commercial access to the transmission system are written in the Connection and Use of System Code (CUSC). This is a legal document which National Grid oversees. It describes what transmission access is, refers to technical and payment obligations which come with having access, and so on.

The actual cost you incur for using the transmission system is set separately by reference to some transmission charging methodologies. The most well-known methodology is the locational Transmission Network Use of System (TNUoS) methodology which apportions the annual charges for maintenance and upgrade of transmission infrastructure. There is also a methodology for Balancing System Use of System Charges (BSUoS) which is currently non-locational and charges out National Grids costs of being a System Operator (SO).

The transmission charging methodologies do not typically prescribe actual costs – instead they describe how the costs of building, maintaining and operating the transmission system are allocated to different classes of transmission system users. The actual costs of these activities are then fed into the methodology which determines the relative costs across different users.

Therefore, if you want to generate onto the transmission system, your costs of doing so are the combined function of:

- (1) What the access the rules say you need in order to go about your business. This is governed by the CUSC. The CUSC can be altered by proposing a change to the legal text via a CUSC Amendment Proposal or CAP.
- (2) The actual costs incurred. This is determined by what users ask for, what they do, what the rules say they can do etc. and how efficient National Grid and the Scottish Transmission Owners (TOs) are in providing it. The costs of the SO and the TOs are regulated by Ofgem in price control reviews.
- (3) Who pays what. This is governed by the transmission charging methodologies. National Grid is currently the only organisation that can propose changes to the transmission charging methodologies, but this could change as part of Ofgem’s Code Governance Review.

Debate arises from the fact that changes will have distributional effects in altering who has to pay what and ultimately the total bill that the consumer will pay. Latterly this debate has broadened into costing the environment as well – for instance will monetary costs now save future consumers the cost of coping with climate change?

4.5 Offshore regulatory regime

A new regime is currently being implemented to make the development of offshore transmission infrastructure a competitive activity (as opposed to licensing the existing TO’s to extend their networks offshore). This new regime defines any offshore electrical asset operating at 132kV or above as a transmission asset, and the act of transmitting electricity needs a license from Ofgem. These new offshore transmission assets are to be designed, constructed and owned by an Offshore Transmission Owner (OFTO) which is appointed as part of a competitive tendering process run by Ofgem (discussed further in Appendix B). National Grid’s role as SO is extended offshore. Figure 4-1 illustrates the ownership and operation boundaries under the new OFTO regime.

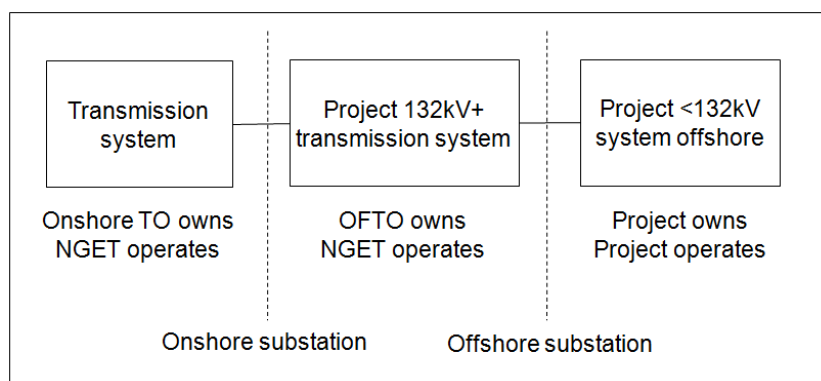


Figure 4-1: Ownership and operation of offshore transmission connections

5 Connection Process

5.1 Introduction

This section of the report discusses the mechanisms for obtaining a connection to the transmission and distribution networks (for generators) along with an indication of the financial liabilities during the respective processes. Offshore transmission connections are also touched upon as they represent a slightly more complex and difficult connection procedure compared to onshore.

5.2 Onshore connection application process

Onshore, the connection application processes for transmission and distribution are similar, with both following the pattern shown in Figure 5-1.

From submission of a formal request for connection, the network operators (DNO or SO) have a statutory 3 months in which to provide a connection offer once the application is submitted (and deemed competent). After the offer has been made, the applicant then has a set period (3 months at transmission and between 1 and 3 months for distribution) in which to accept the offer. As part of the offer the customer will be given a list of the work on the network that will be required to accommodate them (the required “works”), the upfront cost for connecting, and a date for connection. There is also typically an annual use of system charge but this does not form part of the offer – the generator is simply liable for the prevailing charge in each year.

The connection date will be the point at which the DNO or SO envisage the connection works can be completed by, and will generally harmonise with the project’s scheduled completion date as far as is reasonably possible. The timeframes will include allowances for obtaining planning permission for any network reinforcement work as well as any new connection assets that are needed to connect the customer to the existing system.

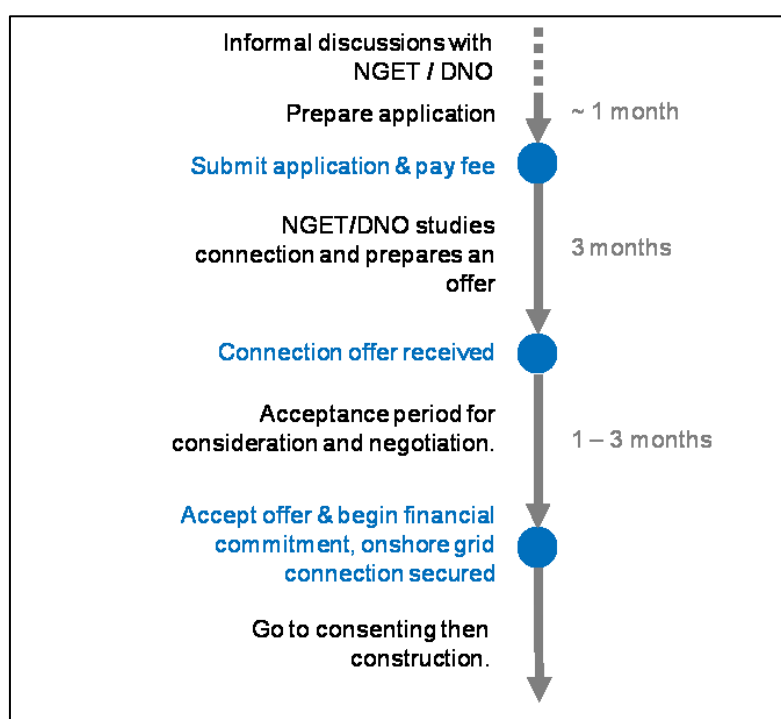


Figure 5-1: Connection process

The offers that are provided during the connection application process vary depending on whether an application for a connection has been made to transmission or distribution. Once the connection agreements have been signed, the processes (and financial implications) for transmission and distribution diverge.

5.3 Transmission processes

At transmission, when the connection offer has been accepted, the relevant TO will move forward with consenting the required connection works (and reinforcements) needed to connect the project. In Scotland this can result in waiting for reinforcements deep into the transmission system, at extremis with offers which have connection dates 'beyond 2018'.

This scenario is beginning to change because National Grid is looking at how it can squeeze more generation onto the existing network. This change of approach has technical and monetary implications which do still need to be resolved if this so-called "Connect and Manage" approach is to be used as the norm. This subject is currently the subject of some UK government consultation and ongoing industry discussion, and discussed further in section 7.2.3.

The implementation of Connect and Manage has not resulted in any changes to the connection application process.

5.3.1 Connection application fees

For the most up to date data on connection charging fees, please refer to NGET's Statement of Use of System Charges (Schedule 2) [17].

At the time of writing, NGET has released a consultation proposing a number of changes to connection application charging methodology, that (if implemented) would relate charges more directly to the size of the project as well as the location [18]. The conclusions of this consultation are expected to be implemented by the middle of 2010.

Transmission connected onshore applications

According to the conclusions document issued by NGET [19], fees for processing connection applications from generators will be broken down into two parts: a base charge (£) plus a rate charge (£/MW).

$$\text{Application fee} = \text{Base (£)} + \text{MW} * \text{Rate (£/MW)}$$

The 'Base' charge and the 'Rate' both vary according to location and size of project. There is a different charge for projects in the north to those in the south, and projects below 100MW, between 100 and 1320MW, and above 1320MW. Charges can vary between approximately £25k and £400k (which is a firm upper limit).

These charges are fixed and guaranteed, but if the applicant so wishes they have the option to reconcile the costs once NGET has completed the connection offer process. This reconciliation could entail further cost or a rebate to the applicant depending on how much work NGET has done processing the application. This is called an indicative charge, and is mandatory for connections that are considered out of the ordinary and difficult to accurately assess the level of resource required to prepare an application. This currently applies to offshore projects, where there is no fixed charge option for connection application fees.

Transmission connected offshore applications

The way to calculate indicative fees for offshore projects is slightly different to onshore. Instead of a base and rate charge, the fee is calculated on the number (and location) of offshore connection points required to connect the project. Per site charges currently vary between £90k and £190k.

$$\text{Application fee} = \text{No. of offshore connection sites} * \text{Charge (£/site)}$$

5.3.2 Connection costs

Generators connected at transmission generally pay very little (compared to distribution) in capital connection costs, as the connection boundary is drawn very close to the project. This is called a “shallow” charging arrangement – most of the cost is recovered via annual use of system fees. However, the generator will be liable for underwriting the transmission works, which is discussed in the next section.

5.3.3 Underwriting

The TO's are generally low risk businesses who get a regulated rate of return from investments that are ultimately paid for by consumers. Therefore, it is normal for generators to be asked to underwrite new infrastructure required to accommodate the project. This provides the TO some protection against the assets being “stranded” if the generator for whatever reason cannot use – and pay off – the infrastructure.

Under this system the generator provides security for the period considered to be most at risk of stranding i.e. between offer signature and project energisation. Currently, underwriting falls away once the project is energised (and paying use of system charges). However, there has been some discussion over whether different or additional periods are ‘at risk’ (i.e. in the first years after project energisation) which could lead to changes in the underwriting arrangements.

There are currently two different methods for underwriting transmission works, Final Sums Liability (FSL) [20] and Interim Generic User Commitment (IGUC) [21]. Both of these methods are discussed in more detail in Appendix A. However, in short:

- IGUC – fixed, quantifiable underwriting that starts at £1,000 x MW when the connection agreements are signed, and ranges up to 10 x TNUoS x MW the year before the connection is established. If a project cancels, the full underwriting amounts are crystallised and there are no refunds, irrespective of actual spend.
- FSL – typically provides modest or low liability on commencement of the agreement (depending on the connection date) but is significantly more variable than IGUC and is directly related to the work to be done/plant ordered by NGET relating to the connection for each financial year. Amounts payable on cancellation are related to whether the assets are actually stranded. Sometimes other projects can make use of the assets.

The benefit of IGUC is that the amounts are fixed and quantifiable which makes it easier to plan and to understand the nature of the risk that you are underwriting. FSL can be variable and unpredictable, but its benefit is that the amounts are refundable if the assets are not

wasted. FSL can also be very low amounts of initial cover when you are at the back of a long queue and very little is being undertaken on your behalf.

5.4 Distribution processes

The offer that a customer will receive from a DNO is slightly different from a transmission offer as it will include the option for the customer to elect to do the 'contestable works'. These works include any item of work that doesn't directly interface with the existing system. Once the connection has been completed, these assets will be adopted by the DNO and will become part of its network, regardless of who built them.

5.4.1 Connection application fees

Until recently, the level of application fee for a distribution connection has been dependent on the location, size and connection voltage of the project and has varied around the country. As of autumn 2008 the regulator, Ofgem, has dictated that DNOs cannot charge for formal connection application processing. However, Ofgem and DECC are currently in the process of consulting on regulations that set out when and how DNOs can levy up front charges.

Charges can arise if there are interactions with transmission. If a Statement of Works from NGET is required because the project may impact on the transmission system then additional fees are incurred [17]. The requirement for a Statement of Works is determined by the impact that the project is deemed to have on transmission assets – as a general rule most distribution-connected projects in Scotland now attract a Statement of Works. Further processing fees can be incurred if the Statement of Works indicates issues.

If, as a result of the Statement of Works, NGET identifies works that are required on the transmission system to accommodate an embedded project, the generator will be liable to underwrite these works.

If the project is large enough (>10MW in SHEPD's network and >30MW in SPD's) it will require a Bilateral Agreement with NGET. These 'Large Embedded Generators' and the types of agreements arranged to accommodate them are discussed in section 5.5 below.

The charge levied for submitting a connection application for an embedded project is calculated using the same methodology as that for transmission connected projects (see section 5.3.1). However, a multiplication factor is used for embedded projects, this factor is currently 0.3 times the fee for a transmission connected project.

5.4.2 Connection cost payment schedules

Distribution connection works are charged through on a semi-shallow or shared reinforcement cost basis. They commence with a capital payment schedule on acceptance of the connection offer which ensures the DNO is cash positive as it undertakes the works to connect the project. For SHEPD the initial payment is normally 25-30% of the total, for SPD it is site specific but 5-20% is typical.

5.4.3 Transmission underwriting

Generators connected to the distribution system may also be liable for transmission underwriting depending on project size and/or impact on the transmission system and this is passed through via the agreements with the DNO or NGET if direct agreements are also in place.

5.5 Large embedded generators

As mentioned previously, if a project is large enough then the generator is obliged to contract with NGET as well as the DNO. This is because the transmission system in Scotland is so heavily utilised that even very small generation developments can impact on power flows and system constraint. The agreement with NGET allows them to bind the embedded generator contractually to provide certain services to them.

Therefore, if a generator is connecting into SHEPD's network (in the north of Scotland) and is larger than 10MW then the generator needs to sign bilateral agreements with NGET as well as SHEPD such that the system can be planned and managed appropriately. Further south, in SPD's network, generators are required to do this if they are larger than 30MW. These agreements with NGET take two different forms: a Bilateral Embedded Generation Agreement (BEGA), or; a Bilateral Embedded Licence exemptible Large power station Agreement (BELLA).

As part of these agreements with NGET, generators are subjected to complying with the CUSC and the Grid Code (both discussed briefly in section 13) which inevitably engenders additional cost to the project due to the more onerous requirements detailed in these agreements. Projects with BEGA type agreements also need to sign up to some energy balancing obligations in the Balancing and Settlement Code (BSC).

5.6 Offshore transmission processes

Offshore transmission connected projects follow a slightly different format to onshore ones. From application for a connection, NGET takes 3 months to prepare a so-called Stage 1 offer, after which the developer then has 3 months in which to accept it.

Ownership of the new offshore transmission infrastructure required for establishing a connection between the existing onshore transmission system and the proposed project needs to be licensed out through a competitive tender to an Offshore Transmission Owner (OFTO). NGET therefore reserves the right to vary the accepted offer until the OFTO is appointed and its plans have been incorporated into the offer.

5.6.1 OFTO tendering

The OFTO tendering process is done in annual rounds, and Ofgem mandates that a generator must have a signed connection agreement to enter the tender window. If one assumes the process starts in April this therefore means, in order to enter the OFTO tender process in April the connection application must be submitted (and the fee paid) the previous year.

The OFTO tendering process then runs for a year, followed by a period of up to three months where the original connection offer is revised to account for the system design submitted by

the OFTO. Finally, the agreements are modified and re-signed with the project developer for the Stage 2 offer.

From start to finish the connection application and OFTO tendering process can take anything between 18 and 36 months, or longer. It should be noted that generators can choose which year to enter the OFTO process and this need not be the next available after signing an initial agreement with NGET. Figure 5-2 gives a graphical representation of this process, more information about the OFTO tendering process given in Appendix B.

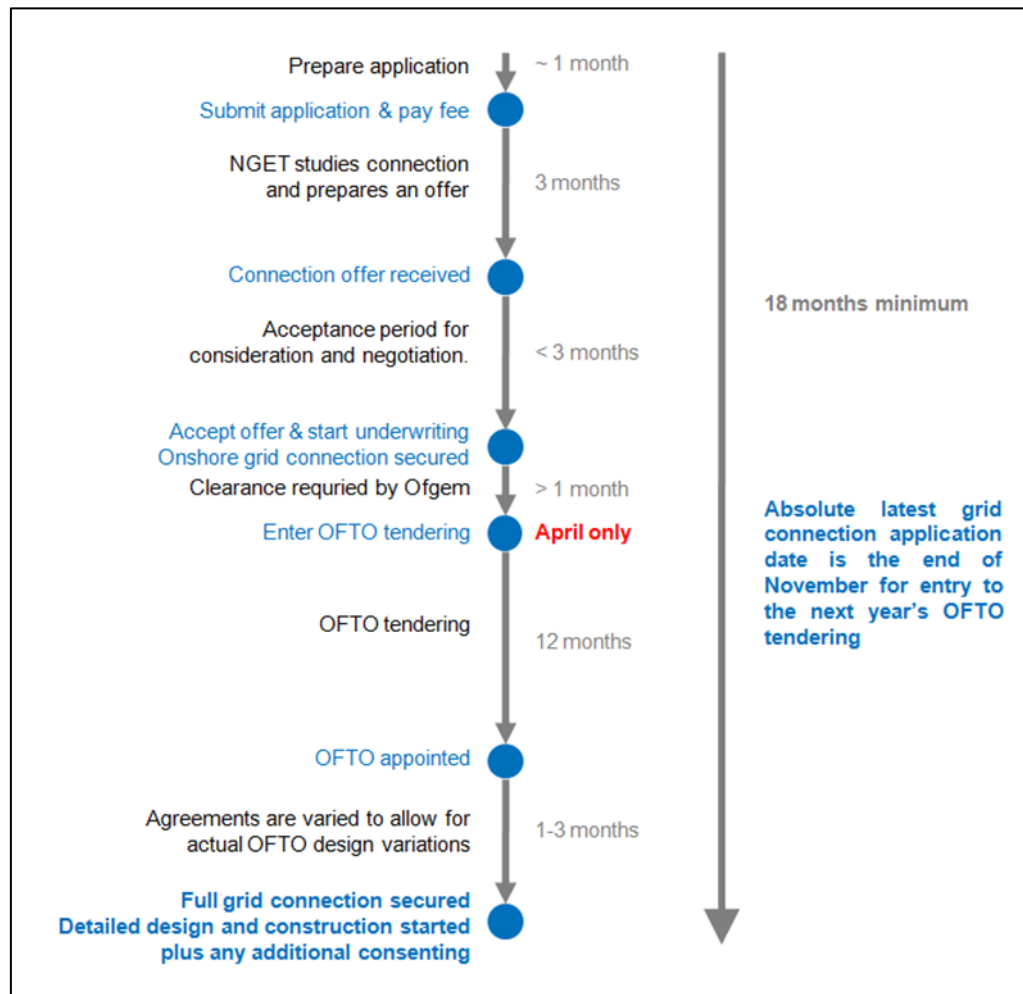


Figure 5-2: Connection process for an offshore transmission connected project

6 Connection issues in Scotland

6.1 Introduction

Access to and use of the grid is one of the most (if not *the* most) critical factors for securing a renewable energy development in Scotland. As mentioned previously, the current and planned generation export in Scotland far exceeds the demand and export capacity from Scotland. This leads to the need for major grid reinforcements from the far north through into England and as far south as the midlands. Power flow issues for export into England across the so called Cheviot boundary (B6), affect all generators north of the border.

6.2 B6 – Cheviot boundary

Much of the power generated in Scotland is used to feed load centres in England. The effect that this currently has on the power flows around the country can be seen in Figure 6-1, while the projected power flows due to the contracted generation and demand for 2016 are shown in Figure 6-2 (generation in blue, demand in red). These flow patterns may increase further after 2014, with the continued connection of renewable energy in Scotland and several large generators including offshore wind (Scottish territorial waters and Round 3). These future developments are discussed further in section 8.2.

This imbalance between Scottish generation and demand is problematic for generators seeking a connection in Scotland as the transmission system is stretched to capacity at many locations, constricting this bulk transport to the south. Therefore, connections in Scotland require reinforcements that stretch deep through the Scottish and English transmission systems. The associated problems and potential solutions are discussed in section 7.

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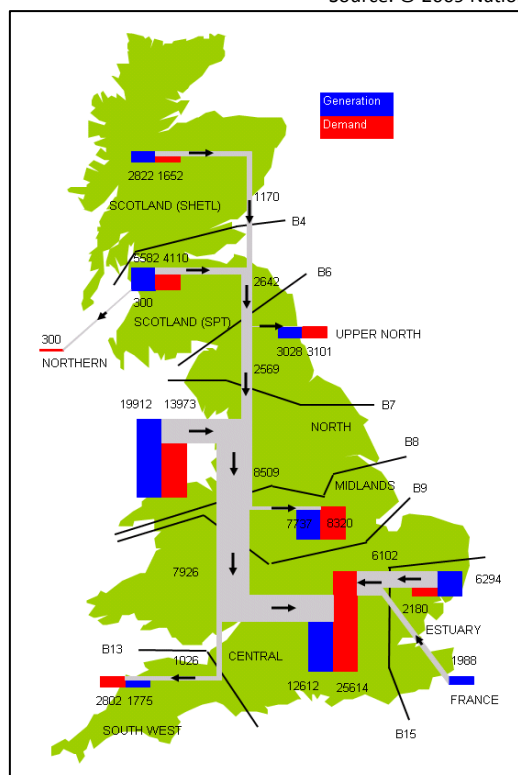


Figure 6-1: Map of GB with power flows down the country in 2008 [2]

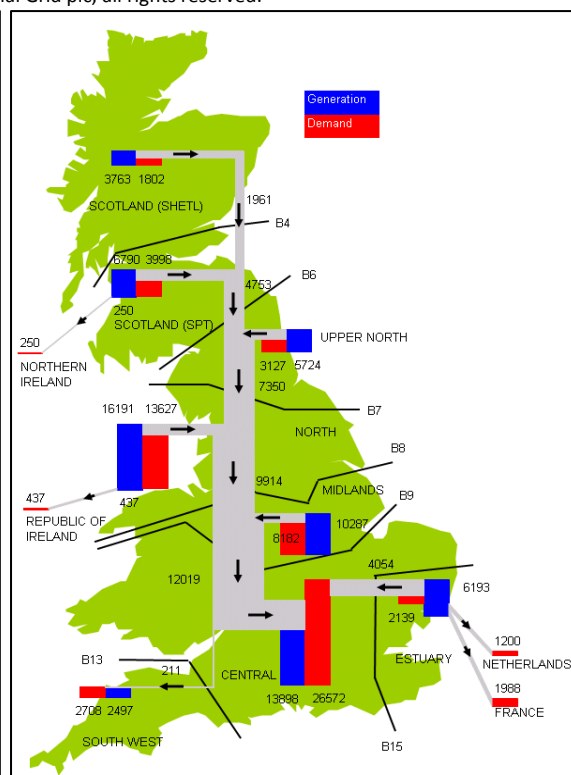


Figure 6-2: Map of GB with projected power flows down the country in 2016 [2]

6.3 Other critical paths

The interconnection between Scotland and England is not the only constraint to generation in Scotland. There are boundaries within Scotland that are also acting as bottlenecks on the transmission system. B1 stretches from Fort Augustus (on the 132kV link between Beaulieu and Denny) in the west to the 275kV circuit at Blackhillock in the east. There is a vast swathe a generation projects already connected and looking to connect to the transmission system north of this boundary. Included in this number is the Pentland Firth wave and tidal development zone, Viking Energy onshore wind and, any and all development on the western isles. Key upgrades that are required in order to address constraint on this link include the upgrading of the Beaulieu – Denny line as well as various reconductoring and upgrade works around the circuit in the north east, from Beaulieu round to Blackhillock and down towards the central belt. Both of these boundaries can be seen in Figure 6-3 below.

These critical paths within Scotland and between Scotland and England have resulted in transmission access queues forming. This issue is discussed further in section 7.2.1.

Source: © 2009 National Grid plc, all rights reserved.

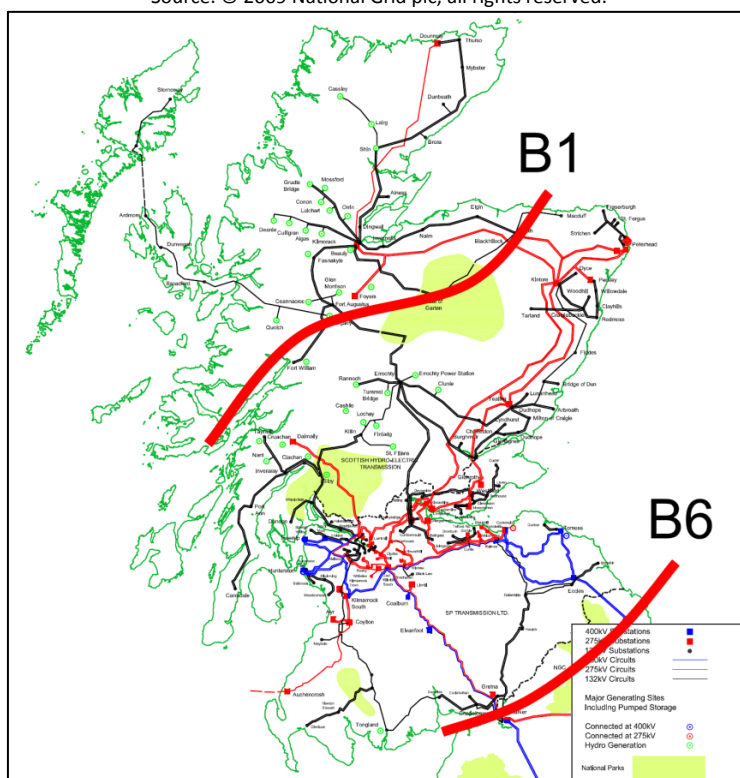


Figure 6-3: Map of the transmission system in Scotland including key boundaries [8]

6.4 Charging and access

As a result of this lack of sufficient infrastructure in Scotland, obtaining access to either the transmission (or distribution) system can be expensive. This expense is levied onto generators as use of system charges (which are high for transmission usage in Scotland) or as connection charges which can be high at distribution (or transmission) depending on a project's proximity to suitable existing assets. Implementation of a "Connect and Manage" regime also has costs for the extra system management required when more generation connects ahead of system reinforcements. Access and charging arrangements are discussed in the next section of this report.

7 Access and charging

7.1 Introduction

This Section goes into a little more depth on some of the grid access and grid charging issues mentioned throughout this guide. It is a changing situation and hence this is written by way of a primer.

7.2 Access

7.2.1 Existing access arrangements and GB Queue

In Great Britain (GB), the regime for connecting generators has been based on an “Invest and Connect” approach. The electricity network is interconnected and is built to collect, transmit, and distribute electricity from generators to demand customers. Generators have needed to wait for grid assets to be built before they could connect, and because groups of generators tend to be contingent on the same assets for transmission of their power, this has led to generators queuing for wider transmission system reinforcements in what is referred to as the “GB queue”.

New applicants in northern Scotland have joined the back end of this queue and hence have been given grid connection dates of “beyond 2018”. This has applied to all transmission connected generators and large embedded generators (above 10MW in the north of Scotland).

According to NGET’s official published figures [22], there is currently over 10 GW of generation scheduled to connect to the transmission grid in Scotland. Any new generation project that seeks a connection in the north of Scotland will be joining the back of this queue when it accepts a connection agreement with NGET. This therefore means, as mentioned previously, that the project will get a “beyond 2018” date for connecting.

The GB queue itself is suffering attrition as projects are terminated and reduced in size. Hence, projects can expect to make progress towards a connection by way of this. NGET has also implemented techniques to manage the queue, discussed below.

7.2.2 Non-firm access

In some circumstances generators can be accommodated on the network if they are willing to accept some restrictions on their access. An example restriction might be that they are asked to accept an “intertrip” scheme which is some equipment which, when armed, will automatically trip the generator off when the network is full. If the likelihood of being tripped off is rare, or if the generator is compensated for the lost access, an intertrip can be acceptable. It is in any event intended as a temporary work around until reinforcements are complete.

These types of restricted access connection agreements are known as “non-firm” (as opposed to “firm” or unrestricted access arrangements). There are nuances around whether the access is financially firm (compensated for the lost access) or whether generators can be denied physical access and not be compensated. Usually a firm offer refers to a financially firm offer, because no generator can be guaranteed physical access to the network all of the time. However the term can be used to describe unusually high levels of physical access restriction, even if there is compensation.

7.2.3 Connect and Manage

An alternative to the invest and then connect approach to connections is “Connect and Manage” where the grid companies allow generators to connect in advance of system reinforcements and take more system operator actions to accommodate them. National Grid has for over a year been operating an “Interim Connect and Manage” approach which allows generators to request an advancement on their existing offer date or, for new parties yet to apply, to state their preferred connection date. National Grid will then do its best to accommodate these aspirational dates.

It is important to bear in mind that the arrangements only allow connection ahead of “wider” system reinforcements because the SO can take balancing actions to control what feeds into and out of the main shared parts of the system. Generators still need to have their immediate “local” works that take their output to the main interconnected parts of the network.

This interim arrangement is due to be formalised as an enduring regime. It should be implemented through a government intervention which is a culmination of years of debate under the Transmission Access Review (TAR). A key area that needed to be clarified through this intervention was who pays for the extra system balancing costs from Connect and Manage. The Department for Energy and Climate Change stated in early 2010 that it was its intention to socialise the constraint costs, meaning that all system users will share the costs in proportion to their output. There are many other areas that have been subject to lengthy debate in TAR, and which are considered in section 8.5 on future developments.

7.3 Charging

7.3.1 Transmission connection & use of system

Connection at transmission level is by way of a shallow charging policy as operated by NGET [7]. The policy is known as a super-shallow policy and is sometimes termed “plugs”. This reflects the notion that the network company provides all the reinforcement and extension works, some of the interconnecting connection assets and all the generator needs do is “plug in”. This is one of the shallowest policies, if not the shallowest, in the EU. The connection charging boundary is very close to the generator.

As discussed in Section 5 this shallow policy means that when connecting to the transmission system generators tend to see relatively low up-front capital connection costs. However they do need to pay annual use of system costs, called Transmission Network Use of System (TNUoS) charges. TNUoS is levied per kW of Transmission Entry Capacity (TEC), which usually equates to a generator’s installed capacity. TNUoS charges are not fixed for the lifetime of a project. National Grid re-calculates everyone’s charge on an annual basis, factoring in changes in demand, generation and revenue recovery amounts.

There is a TNUoS methodology which determines the relative allocation of transmission costs across users. This is a “locational” methodology which seeks to reflect the cost of transporting electricity from its source to its destination. In summary this means that generators in Scotland pay relatively more than generators in the south of England. The further north you go the higher the charge gets. There has been intense debate around whether this locational charging methodology is appropriate. This is a complex area and is not discussed further here.

7.3.2 Distribution connection & use of system

Distribution has a similar split between capital payments for connection costs and ongoing annual use of system charges, called Generator Distribution Use of System (GDUoS) charges. Connection tends not to be as shallow at distribution as it is at transmission. GDUoS is also adjusted on an annual basis and each DNO will publish the current year’s tariff schedule.

There has been ongoing debate between DNOs and Ofgem over whether GDUoS should be levied on a more locational basis in a similar manner to TNUoS. Ofgem also wanted the DNOs to adopt the same methodology for allocating GDUoS – although note this would not mean the same charges for each DNO, but rather that the principles for allocating costs amongst their customer base would be the same. The upshot of this is that DNOs have a choice of two methodologies when levying GDUoS.

In addition to a connection charge and GDUoS, distribution connected generators could also be asked to pay TNUoS. This is because the network is interconnected and changes at distribution can impact on investment levels at transmission. Again this has been a quite intense debate and it is too complex for this guide. Suffice to note that distribution users should be aware that they could be exposed to TNUoS costs, and to monitor these developments in the Transmission Access for Distributed Generation (TADG) discussions.

8 Looking forward

8.1 Introduction

This section of the report provides a brief overview of ongoing work streams and likely future developments that will shape transmission and distribution in Scotland. It is important to note that there are many things to consider and it is only possible to present a brief and targeted overview within this report.

8.2 New generation

Without a doubt, Scotland will continue to see further growth in new generation. There are likely to be some closures of existing generation plant within the next 10-20 years but there is currently over 10 GW of new generation contracted for connection with NGET [22] and more at distribution level.

Added to the above is a further 6.5GW of Scottish Territorial Waters offshore wind which is leased and does not yet have any formal grid connection agreements [23] and, around 4-5GW further offshore, outside of territorial waters (called "Round 3"), in the Moray Firth and Firth of Forth [24]. The Crown Estate has also leased 1.2 GW of wave and tidal energy in the Pentland Firth region and it is expected that this will be followed by more leasing around Scotland [25]. These developments are shown graphically in Figure 8-1 below.

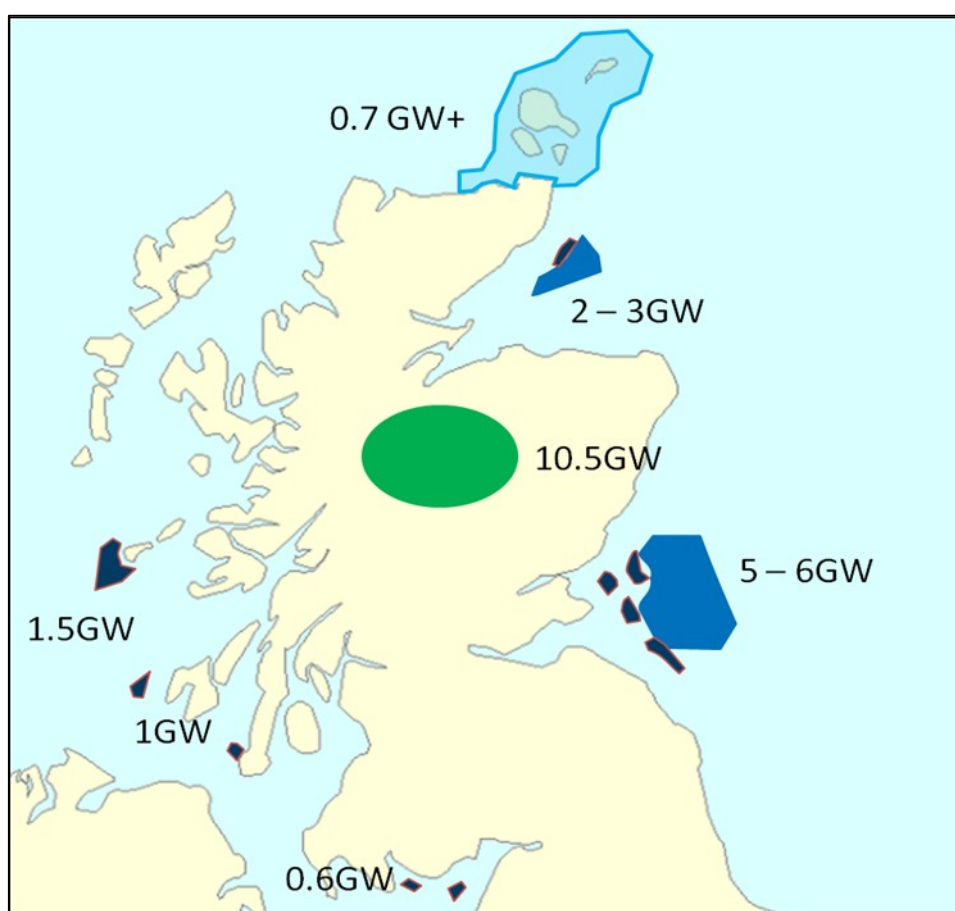


Figure 8-1: Generation background 2020

8.3 System reinforcements

There is already an extensive top to bottom programme of reinforcements planned for Scotland, much of which, even if all approved in funding and planning terms, will not be complete until nearly 2020. They include links to Shetland, the Western Isles, and probably Orkney in the near future. The Energy Networks Strategy Group (ENSG) [8] has put forward further reinforcements which include substantial offshore HVDC links on the east and west coasts, see Figure 8-2. Subsea links have largely been examined to avoid outage costs incurred when reinforcing onshore works and to avoid onshore planning issues.

Source: © 2009 National Grid plc, all rights reserved.

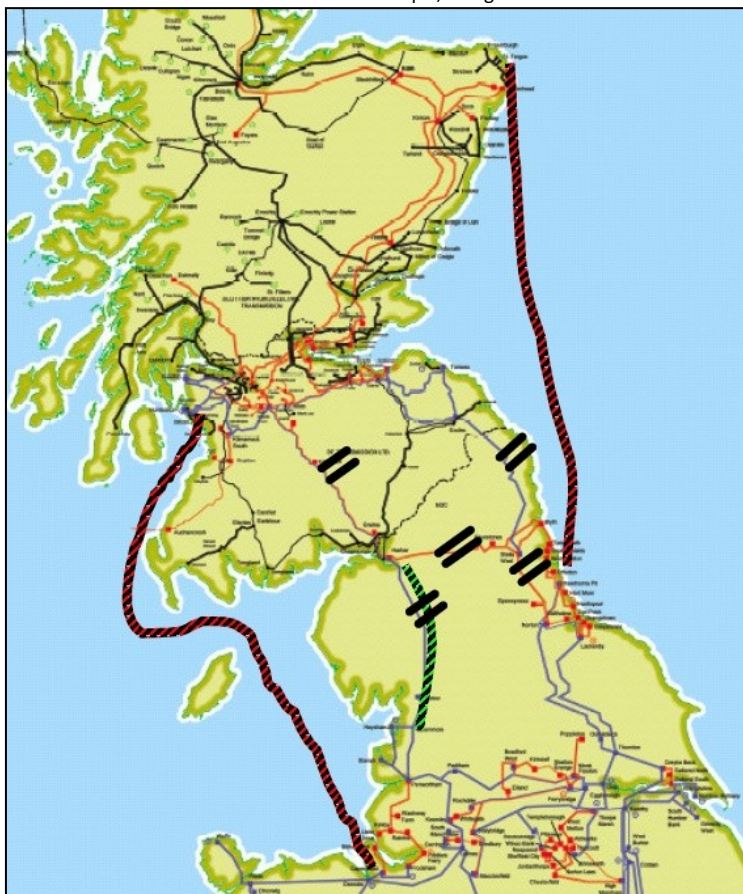


Figure 8-2: ENSG report [8]

The Scottish Government has also spearheaded initiatives to facilitate interconnections between neighbouring countries and offshore renewables projects. On the west coast this is a fully-fledged feasibility study under the ISLES project, which is part-funded by the European Union's INTERREG IVA Programme.

8.4 Offshore Transmission Owners (OFTOs)

Due to the offshore generation projects in progress it is likely that Scotland will see a number of OFTOs. These OFTOs will supplement the onshore TOs.

8.5 Regulatory developments

8.5.1 Enduring connect and manage

In light of a very large queue of principally renewable generators wanting to connect to the Grid, June 2009, the National Grid published guidance on an 'Interim Connect and Manage regime' to advance the GB queue. It allows generators to get transmission access without the finalisation of 'wider works' (while local transmission work needs to be completed before connection). One challenge is the mitigation and allocation of additional constraint costs from needing to balance the extra generation.

After a Transmission Access Review conducted by the wider industry, DECC proposed in September 2009 different scenarios for an 'Improved Grid Access' regime, all of which were based on Connect and Manage but which differed by their treatment of constraint costs. In early 2010 DECC made a decision to socialise constraint costs. At the time of writing this decision needs to go through a legislative process for it to become a permanent feature of the charging regime. It is expected that an enduring Connect and Manage regime will be in place by June 2010.

8.5.2 Postage stamp charging

Last year (2009) the Scottish Government, Scottish and Southern Energy, ScottishPower and Scottish Renewables made a formal proposal to National Grid to change the existing system of locational charging. The proposal was to move to a so called 'postage stamp' system where generators pay a flat charge per MWh generated irrespective of location within GB [26]. National Grid did not agree with the abolition of locational charges, but agreed to look into charges for renewables generators, as well as some problems with the unpredictable changes in annual TNUoS tariffs.

Further developments are likely – especially on charging for renewables (see following Section below) – although alignment with the large number of European countries that do not charge generators for use of the transmission system or do charge on a postage stamp basis [27] is perhaps unlikely for the foreseeable future.

8.5.3 Wind charging and SQSS review

The GB SQSS has been subject to a "fundamental" review for a number of years. Progress has been quite slow, in part because of some overlapping work on access and charging in TAR. A key area under review is how much variable, low load factor generation can be allowed to connect to a certain amount of transmission capacity. The rationale is that its low load factor should allow sharing of transmission capacity and therefore allow more generation capacity to use a given amount of transmission capacity. There is however no foreseeable conclusion to this work at present.

At the same time, National Grid is working on a new transmission charging methodology for wind power that would reflect its lower usage of the transmission system (lower than base load power stations). This is aligned to work on the SQSS and TAR described above.

8.6 Beyond 2020

Moving further into the next decade and beyond it is clear that many other factors will affect the transmission and distribution landscape. These may well include the development of super-smart grids; an increasing interconnection with Europe and the use of energy storage for balancing and services.

8.6.1 Energy storage

Compared to other energy sources, the uptake of the storage of grid electricity (large scale) appears still limited. However with the utilisation of a large share of variable/intermittent renewable energy sources, the storage of grid electricity becomes more important. A variety of storage facilities are developed such as pumped hydro storage¹, compressed air energy storage², advanced battery solutions³, flow cells⁴, kinetic energy storage -flywheels⁵, super capacitors, magnetic energy storage, but as well electric or Plug-in Hybrid vehicles are now considered as storage alternatives. Nonetheless, most existing alternatives are restricted in order to exploit them on a larger scale, e.g. due to high costs. Similar to renewable energy sources, storage facilities may benefit from subsidies to demonstrate performance and develop much needed economics of scale.

8.6.2 Super smart-grids

Various definitions for the 'smart grid' exist. The European Technology Platform defines the smart grid as an "... *electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies. A smart grid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies*". Integrated information technologies allow 'real-time' information exchange between supply and demand and a set of storage alternatives allow reliability and security of supply and the utilisation of an increased share of variable/intermittent renewable energy technology. A 'localised' smart grid may not be able to rely on its own infrastructure. A 'super smart grid' is needed; interconnecting several smart grids across geographical regions by utilising HVDC for long distance transmission. The aggregation/interconnection of a variety of geographical regions can help to manage the variability/intermittency of some renewable energy sources. Such an exchange of power between regions/countries provides a level of flexibility, stabilising the electricity flow by balancing systems of territories that consumes more than generate with neighbouring systems that generate more than consume. As a consequence, System Operators may need lower reserve requirements.

One example for a 'super smart grid' is a single-EU energy market. It is envisaged to integrate (rather than just connect) existing regional initiatives in order to exploit for

¹ Pump water to higher reservoir in time of electricity surplus, which can be released at times of peak demand.

² Use low cost electricity to compress air into large caverns which can then be expanded via a fired turbine unit.

³ Lead-acid battery systems are one of the most developed, but tend to have a limited cycle life and concerning footprint. Some sodium sulphur battery systems are in operation in Japan and the US, up to 6MW, 8hr unit for Tokyo Electric Power Company. Lithium-ion systems are currently used in much smaller applications and there are a number of emerging challenges which will need to be overcome for the technology to be scaled up.

⁴ Operate differently from battery systems with the chemical reaction taking place in a reaction cell.

⁵ Flywheels and Super Capacitors presently tend to have greater application in large commercial or industrial sites to maintain energy supplies, rather than as part of the main electricity network.

instance the offshore wind potentials in Europe. Norwegian TSO Statnett is proposing a HV 'super-grid' vision by linking the offshore grid of Scandinavia with surrounding nations.

An essential element of a single, competitive EU energy market will be coherence and convergence with regard to systems and regulations. Among others, the Council of European Energy Regulators is working on issues around the cooperation of independent energy regulators of Europe and initiates the exchange, e.g. regarding smart metering, balancing and energy storage.

In line with the Third Package (of Regulations and Directives), another organisation, the Agency for the Cooperation of Energy Regulators (ACER) has been set up, and will be fully operational in March 2011. It will provide a framework for national regulators to cooperate and will have the regulatory oversight of the cooperation between transmission system operators. It is envisaged, that legally binding Euro Network Codes, which will take precedence over national rules, will be drafted by the European Network for Transmission Operators and will be approved by ACER.

Recognising the potential role of smart grids for the UK energy market, the smart grid working group of the Electricity Networks Strategy Group outlined a smart grid route map for the UK; outlining the potential path to test the feasibility, costs and benefits of smart grid technology. In parallel, the Energy Networks Association established a task group on smart networks; combining the industry's leading experts and feeding into the Electricity Networks Strategy Group.

9 Summary

9.1 Transmission and distribution basics

Electricity networks are split according to voltage, in Scotland circuits operating at 33,000 volts (33kV) and below are classed as distribution, while circuits operating at 132kV and above are transmission assets. Transmission is used for bulk power transport, while distribution is used for supplying towns (33kV) and routing power through urban areas and supplying rural communities (11kV). The transmission system in Scotland is sparse, with no 400kV assets at all north of the central belt. There are extensive distribution networks all over Scotland, including most of the isles. However these networks are generally very limited in their ability to accommodate large generation projects.

The commercial and technical frameworks that govern transmission and distribution differ from each other. In general the technical standards and commercial arrangements that customers must comply with are less onerous at distribution than at transmission.

9.2 Industry overview

9.2.1 Electricity networks

The generation, transmission, distribution and supply of electricity are all regulated by one government body – Ofgem. At transmission, the networks have a system operator (NGET) and separate owners (SHETL in the north and SPT in the south). In England, NGET also owns the transmission system as well as operating it. At distribution, the networks are owned and operated by a single company called a DNO; SHEPD is the DNO in the north of Scotland and SPD in the south.

SHEPD and SHETL are subsidiary companies of SSE, while SPT and SPD are subsidiaries of Iberdrola. All of these companies (including NGET's system operator and transmission owner businesses) must operate with strict business separation rules in order to comply with competition laws.

9.2.2 Other players

The real time balancing of the transmission system is performed by NGET as SO. However, the balancing and commercial settlement, pre and post real time, is performed by the market operator – Elexon.

Users of the transmission system include large generating stations (e.g. Hunterston Nuclear, Cruachan Hydro), with very few demand customers directly connected. At distribution there tends to be smaller generation projects, as well as a number of large (industrial) demand customers.

All demand and generation users must sell and/or buy electricity via an electricity supplier.

9.3 Commercial and regulatory frameworks

9.3.1 European level

At a European level there are currently various relevant legislative movements, including the 'Third legislative package' requires further liberalisation of the energy markets and therefore requires stricter business separation and transparency between market players. There is also the Renewables Directive that requires EU member states to take steps towards establishing beneficial charging and infrastructure changes to accommodate new renewables.

9.3.2 UK legislation

In the UK, the Electricity Act 1989 provides the back drop for the privatised (but regulated) market. There are various codes and standards that govern the transmission and distribution systems, with key documents including: Grid code, SQSS, BSC, CUSC and various statutory statements required from the SO and DNOs including charging methodologies and development statements (SYS at transmission and LTDSs at distribution).

Price control reviews are the mechanisms used to incentivise the network operators and owners to improve efficiency, reliability and to trial new approaches of system operation. These reviews are performed separately for transmission and distribution.

9.3.3 Offshore

There is a new regime that has been designed for offshore transmission (any offshore asset operating at 132kV or above) in response to the current and expected offshore wind, wave and tidal developments. This regime will appoint OFTOs to own these offshore assets, and extend NGET's role offshore as SO.

9.4 Connection process

9.4.1 Onshore

The processes for obtaining a connection at transmission and distribution are similar. After the customer (e.g. generator) submits an application for connection, the network operator takes up to three months to prepare an offer. After which, the customer has between one and three months to accept the offer. At transmission, there are fees levied for submitting a connection application. DNOs are no longer allowed charge for the submission of connection applications. However, if an embedded generator requires to contract directly with NGET (i.e. if the project is >10MW in the north and >30MW in the south) there are fees associated with processing this application.

Upon acceptance, the customer will either have to underwrite the connection (at transmission) or begin paying capital (at distribution) according to a schedule in order to advance the connection works. Underwriting can take two forms: FSL (unpredictable – correlating to expected annual expenditure) or IGUC (fixed and quantifiable according to a methodology).

9.4.2 Offshore

For offshore transmission connected projects, the process is slightly more complicated. Once the customer accepts the connection offer, the project enters a yearlong OFTO tendering process to appoint a preferred bidder to design, construct and own the offshore assets. The customer will have to underwrite the onshore works at initial acceptance, but is not required to underwrite offshore works until after the appointment of the OFTO.

9.5 Connection issues in Scotland

The level of installed generation currently outstrips demand in Scotland by a ratio of 1.73:1; this therefore means that Scotland is a net exporter of electricity to England (and Ireland). The interconnection (B6 / Cheviot Boundary) between Scotland and England is currently rated at 2.2GW. These circuits are already operating at full tilt, and hence are being upgraded to 3.3GW in 2012/13 with further uprating to 4GW expected subsequently. These planned upgrades are set against approximately 10.5GW of generation currently queuing for connection in Scotland (not including any offshore development, except Beatrice offshore wind farm). The infrastructure required to connect all of this queued generation is not expected to be completed until at least 2018 (mainly due to planning issues), which results in serious network access issues for generators in Scotland. On top of this, due to the significant amount of infrastructure required to take all of this electricity south to demand centres in the midlands and London etc, the transmission use of systems charges for generators in Scotland are considerable.

There are also network constraints within Scotland, notably in the northwest along the Beaulay to Denny 132kV circuits and the 275kV circuits running from Beaulay to Blackhillock and then south.

9.6 Access and Charging

Over the last few years there have been strong indications that the transmission access and charging regime would undergo some major reform. The Transmission Access Review debated a complete overhaul of how access was allocated, and there have been various proposals on charging from pay-as-bid auctions to postage stamp charges. In the event there has been no fundamental change to the charging regime.

However, there has been a major change to the access regime with the introduction of Connect and Manage. This means that more generators have access to the transmission system than previously. The change is important for new generators as it should improve their chances of getting a connection date of their choosing. However it won't solve all of the problems associated with an increasingly congested network. Work on building new capacity will be critical, as well as decisions on what generation is required where for security of supply purposes.

9.7 Looking forward

Over the coming years, the generation landscape in Scotland is expected to change significantly, with 10.5GW of new onshore generation planned. This number does not include any of the planned offshore wind (up to 11.5GW) or any wave and tidal development (0.7GW+ expected in the Pentland Firth alone). This generation will need require serious transmission reinforcement in order to accommodate it. Therefore, there are proposals to use large subsea links down the east and west coasts to bolster the existing system.

Along with these physical changes to the networks, there is also going to be a number of regulatory changes, including enduring connect and manage which will allow generation to connect ahead of wider transmission works being completed. It is also expected that transmission charging may move to a system based on per MWh exported instead of per MW installed.

Beyond the medium term there is potential for utilising smart grid technology alongside energy storage in order to maximise utilisation of infrastructure and facilitate more renewables penetration onto the grid.

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11 Appendix A – transmission underwriting

11.1 Introduction

The size of the connection (MW capacity) is a driving factor for the level of underwriting cost a user must bear during the connection process but location of the project is also a critical factor.

Transmission Network Use of System (TNUoS) charges are the ongoing annual charges that projects pay for use of the transmission grid but can also be a determinant in the setting of underwriting sums.

There are currently two transmission underwriting methodologies which can be chosen. They are:

1. Interim Generic User Commitment (IGUC) [21]. This gives fixed and quantifiable liabilities that are capped at a moderate level before consents are obtained for grid works and ramp up significantly thereafter.
2. Final Sums Liability (FSL) [28]. This gives project specific liabilities that can vary with the changing background, sometimes dramatically. They tend to be moderate initially but rise as the works progress.

Underwriting liabilities apply during the formal process of getting connected and provide security to the transmission companies against transmission grid works becoming stranded if generators withdraw from being built. If the project getting connected terminates ahead of connection the security payments are taken by NGET to cover costs, i.e. the liabilities are not refundable upon termination. If the project proceeds to connection the underwriting sums fall away, i.e. are zero. This may change in the near future with the period of liability extending into the first number of years after a project has connected and energised.

11.2 Final Sums Liability (FSL)

FSL underwriting sums can be difficult to assess. They are closely linked to the actual anticipated annual spend profile for the required transmission works. This means deep (and sometimes distant) reinforcements may be triggered and need to be underwritten.

FSL is the default position for onshore and offshore projects and will apply at signature of the connection offer. FSL amounts are directly related to the costs of the works needed to connect the project. FSL increases over time following an “S-curve” typical of the expenditure profile, i.e. small initially as only desk-top and environmental survey work is required, then increasing substantially once equipment is ordered and the works move to construction. Figure 11-1 gives an example of FSL underwriting liabilities for a large project signing agreements in 2009 and with a 2016 delivery date.

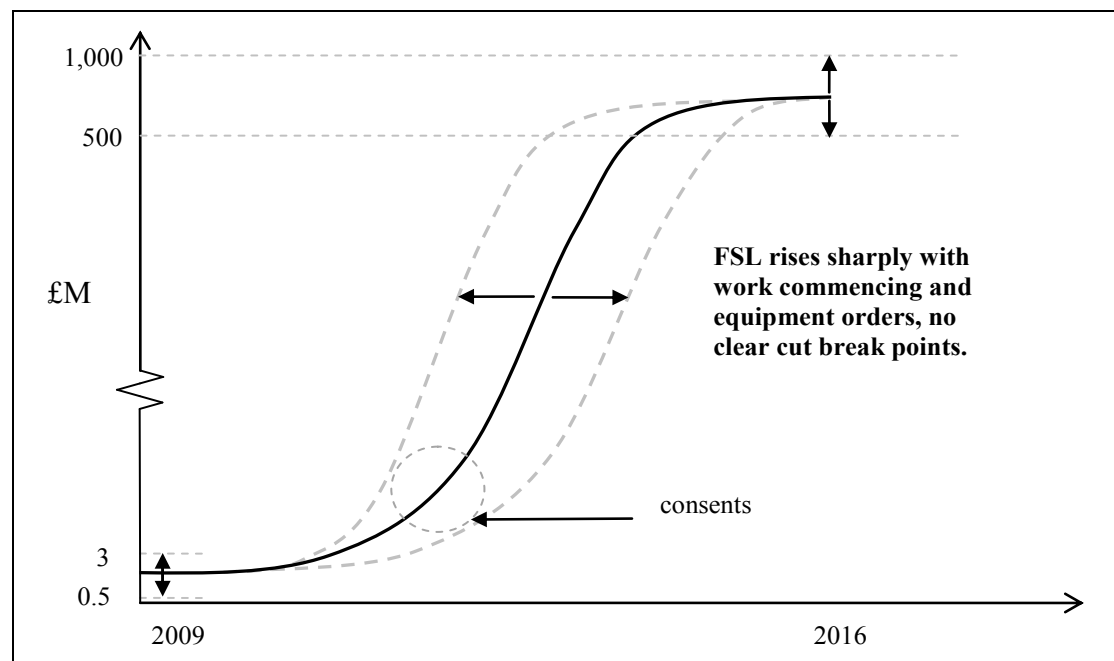


Figure 11-1: Liabilities expected, per project based on the FSL methodology [2]

11.3 Interim Generic User commitment (IGUC)

Underwriting liabilities under IGUC fall into two parts:

- Fixed costs ahead of grid consents denoted User Commitment.
- Fixed costs from granting of consents to completion of the necessary works. These are termed Cancellation Liability.

User Commitment Amounts are fixed at £1 per kW per year but capped at a maximum £3 per kW until the grid consents are obtained. Once the necessary grid consents are obtained the Cancellation Liability applies, which is calculated from the project kW capacity and the Transmission Network Use of System (TNUoS) charge as follows:

$$\text{Total Cancellation Liability} = \text{kW} \times 10 \times \text{TNUoS (£/kW)}$$

The Cancellation Liability is split over four years prior to completion and ramps up in 25% (of the end total) increments per year. This can be seen graphically in Figure 11-2. The example is based on a connection date in 2016, with grid consents obtained in 2012.

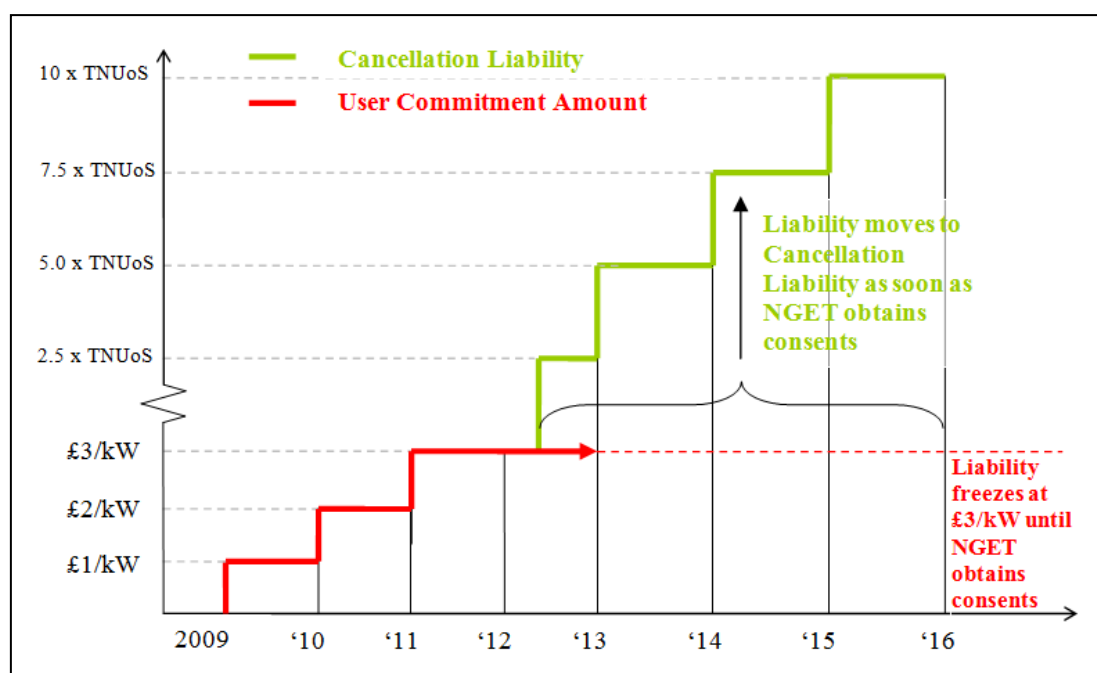


Figure 11-2: IGUC liability profile for grid consents in 2012, delivery 2016

12 Appendix B – OFTO tendering process

12.1 Introduction

The contract with an OFTO to design, build and own offshore transmission is awarded through a competitive tender process as set out below. The OFTO tendering process will initially be run on an annual basis (provisionally set to commence each April). This is to allow prospective OFTOs to bid designs which could encompass more than one developer, project and/or zone, the notion being to encourage cost efficiency. To enter the process an offshore generator must have a signed connection agreement with NGET and appropriate lease arrangements in place.

12.2 Annual process

The yearlong tendering process consists of the following stages.

12.2.1 Qualification stages

After Ofgem advertises the offshore project, OFTO bidders will need to respond to a pre-qualification and then a further qualification stage to basic competencies of the bidders in order that all the bidders at the subsequent stages all have the ability to actually deliver the offshore transmission assets required.

12.2.2 Invitation to Tender stage (ITT)

Once the OFTOs are properly qualified the offshore generator populates a data room with project information so that the OFTOs can prepare their detailed bids at the ITT stage. Bidders will be given four months to prepare and respond to the ITT.

12.2.3 Preferred OFTO bidder

The preferred OFTO bidder will be expected to fulfil a number of conditions at the preferred bidder stage. These include a demonstration to Ofgem that the financing proposals set out in its bid are in place. Once complete the successful OFTO is appointed.

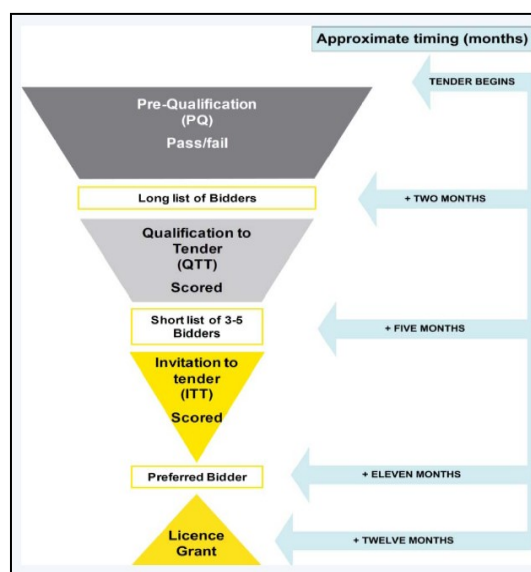


Figure 12-1: OFTO tendering process

13 Appendix C – Key industry documents

13.1 Transmission – technical codes

13.1.1 Security and Quality of Supply Standard (SQSS) [29]

The minimum set of criteria and methodologies that transmission licensees must use in the planning and operation of the transmission system is called Security and Quality of Supply Standards (SQSS). More detailed criteria are contained in the Grid Code.

13.1.2 Grid Code [30]

The technical code which defines the planning, connection conditions, operation and testing requirements for the management of the transmission system is referred as the Grid Code.

13.2 Transmission – access and charging

13.2.1 Connection and Use of System Code (CUSC) [31]

The legal document that constitutes the contractual framework for connecting to and using the transmission system is the Connection and Use of System Code (CUSC). The CUSC defines the stages for connection and application to a use of system agreement, as well as for disconnection. It also sets out the nature of “access” to the system.

13.2.2 Transmission charging methodologies

The costs for building and maintaining the assets that facilitate connections to the transmission system are recovered through a range of charges that a transmission system operator charges to all parties that connect to/and use the transmission system (e.g. generators and suppliers). These charges embrace the Connection Charges, the Transmission Network Use of System (TNUoS) and Balancing Services Use of System Charges (BSUoS).

There are charging methodology statements published on NGET’s website [32], [33].

13.3 Distribution – technical

13.3.1 Distribution Code [34]

Licensed DNOs need to maintain a Distribution Code, which comprises the technical framework and restrictions relating to the connection and use of their electrical networks.

13.4 Distribution – access and charging

13.4.1 Distribution and Connection Use of System Agreement (DCUSA) [35]

This forms a similar function to the CUSC for users of the distribution system. It has tended to be dominated by Suppliers and DNOs, although this may change in the future with increasing amounts of distribution-connected generation. Some new distribution charging methodologies are being brought under the governance of the CUSC, which means that parties to the DCUSA will have a formal role in any changes to the charging methodologies.

System charging - distribution charging

The electricity distribution licences requests each distribution licensee to prepare a methodology in respect of the charges for connection to its distribution system and a methodology in respect of the charges for the use of the distribution system.