Supporting Document 05

Information to support our proposed

growth capital expenditure programme

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Overview

This document sets out Scottish Hydro Electric Transmission Limited's (SHETL) approach to network investment during the RIIO-T1 price control period (1 April 2013 to 31 March 2021).

We need to invest in our network over the coming decade in order to accommodate the growth in renewable generation across the north of Scotland. Thus our investment planning is dominated by our assessment of the requirements of future renewable generation; we do not expect demand for electricity to change significantly from current levels.

In this document we detail the generation scenarios which form the basis for our investment planning, together with the resulting transmission projects that will be required to connect and provide grid capacity for that generation. We also detail how we propose to address the challenges that the investment programme brings in terms of uncertainty and deliverability.

Throughout our customer and stakeholder engagement, our stakeholders have been supportive of our role and approach to developing the network to accommodate renewable generation, and many have identified this as their most important issue.

For example, one stakeholder stated:

"…the delivery of an electricity transmission network which enables new generation to connect in line with its project timelines whilst helping to maintain security of supply in a cost effective manner is crucial to the delivery of Government 2020 targets and beyond. We therefore welcome the stakeholder engagement that SHETL is undertaking for its planned approach."

And another stakeholder said:

"…the expected drive for increased use of low carbon energy via the electricity network needs to be supported by a reliable network. It is essential that the network enables sustainable low carbon energy to be connected and minimises network constraints. The investments set out in SHETL's Green Paper will help the UK achieve these measures."

We believe that the approach we describe in this document represents a pragmatic approach to network development that ensures that the right network is delivered at the right time and at the lowest possible cost to customers.

Information to support our proposed growth capital expenditure programme

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Generation scenarios

This section sets out in detail our approach to identifying a set of generation scenarios as a basis for our RIIO-T1 investment programme.

In our planning, we distinguish between our investment programmes for the connection of individual renewable generation projects and for the development of the wider transmission system. In order to assess the range and timing of these programmes, it is necessary to adopt a central generation scenario and then examine the possible sensitivities.

In this section we discuss:

- Context
- Planning the network to meet current and future customers' needs
- Summary of our views on generation
- Establishing generation scenarios – The role of the ENSG
- SHETL's 'Best View'

Context

Over the coming decade we expect to significantly expand our network to facilitate the growth of renewable generation in the north of Scotland in order to meet UK and Scottish renewable energy targets. The potential scale and timing of this investment is not fixed as it depends on new generation projects proceeding. It is important for us to assess the most likely scenarios for the development of generation in the north of Scotland, in terms of volume, phasing and location of the different renewable technologies.

Current targets are for the UK to meet 15% of its energy demand from renewable energy, and for Scotland the Scottish Government's target[1,2] is for 100 per cent of Scotland's electricity needs to come from renewable sources by 2020.

Most forecasters expect that renewable electricity generation will be critical to achieving the national 2020 carbon reduction targets.

[1] http://www.scotland.gov.uk/Topics/Business-Industry/Energy/Energy-sources/19185/17612

[2] http://www.scotland.gov.uk/News/Releases/2011/05/18093247

Generation scenarios

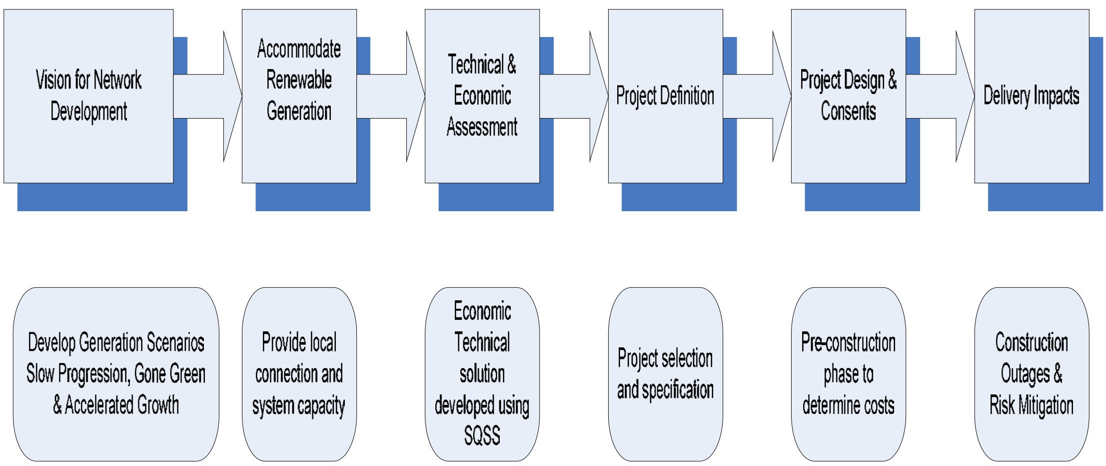
The national electricity transmission system, of which our network is a part, will play an important role in supporting the growth of our low carbon economy. As we plan for the next decade, we do not know exactly who is going to connect to our network or when. The generation scenarios we set out here are designed to assess and manage the uncertainty with the objective of matching the pace of transmission infrastructure development with that of renewable generation.

Planning the network to meet current and future customers' needs

Planning the network to meet our users' needs is one of the most important things we do.

Figure 1 illustrates the investment planning process, and the requirement at the beginning of the process to establish scenarios for the future development and connection of new generation in order to assess the requirement over the RIIO-T1 period for local connection and infrastructure works, as well as developing the wider interconnected system to ensure adequate transmission capacity.

Figure 1 Illustration of the components of the investment planning process



Generation scenarios

In transmission network planning there are rules that are set and administered at a national level which are used by all transmission companies. The most important of these rules is the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS), which sets out minimum criteria for the development and operation of the national electricity transmission system. Through application of the NETS SQSS, we gain an understanding of how much transmission infrastructure we might need to meet users' needs.

However, to do this there are uncertainties that need to be identified, assessed and a 'best view' reached.

We believe that the use of electricity in the north of Scotland is going to broadly remain at current levels over the coming decade. This is an important planning assumption.

The main uncertainty we face is in the future for renewable generation, which we believe will increase in the north of Scotland over the coming decade. However, we are uncertain about the volume of new generation that will be developed, where it will be locate and the timing of its connection. These were important questions in our stakeholder engagement. We believe that taking a GB-wide view of possible generation scenarios with a local sense-check of individual generators' aspirations, and the application of national planning standards, provide a robust engineering approach underpinned by evidence as the best way to plan for the future.

Summary of our views on generation that might want to connect to our network

The assumptions we make about generation that will connect to our system are critical to our investment planning decisions. If we get this wrong, then we might build too soon or too late. We recognise the potential cost to customers of getting our investment decisions wrong. We have been keen to understand the views of stakeholders on what might be our future generation mix in the north of Scotland, both over the RIIO-T1 period to 2020/21, but also taking a longer term view to 2030.

In this section we set out our views on onshore generation, wave and tidal generation, and offshore wind generation. We have used renewable generation growth forecasts based on UK and Scottish government targets, together with information from developers both in the form of their forecasts and their contracts for connection.

Generation scenarios

The established contracts provide a good basis for determining the requirements to provide local connection and new infrastructure works in order to connect the individual generation projects into the existing network. These contracts and broader forecasts provide the basis for assessing the requirement to develop the main interconnected 275kV and 400kV transmission system, and the requirement for HVDC links.

Onshore wind generation

Onshore wind generation is the predominant renewable generation technology that is actively connecting to the transmission system at the commencement of the 2010-2020 period. The activity is forecast to remain strong over the coming decade, with a number of large wind farm projects commencing construction following the gaining of consents and financing. Smaller-scale wind, hydro and other forms of renewable generation are also expected to continue to develop. The connections of these small schemes onto the lower voltage distribution networks will increase the export of power onto the transmission system and, hence, impact on our investment plans.

Figure 2 shows the anticipated connection profile based on some 4.5GW of contracted onshore generation in Spring 2011. This figure only reflects projects that have already entered into connection agreements with us. Clearly there will be other schemes in development that we are not aware of and this volume will increase in respect of later connection dates, as these schemes become known. Similarly, some currently contracted schemes may not develop and offset an overall growth.

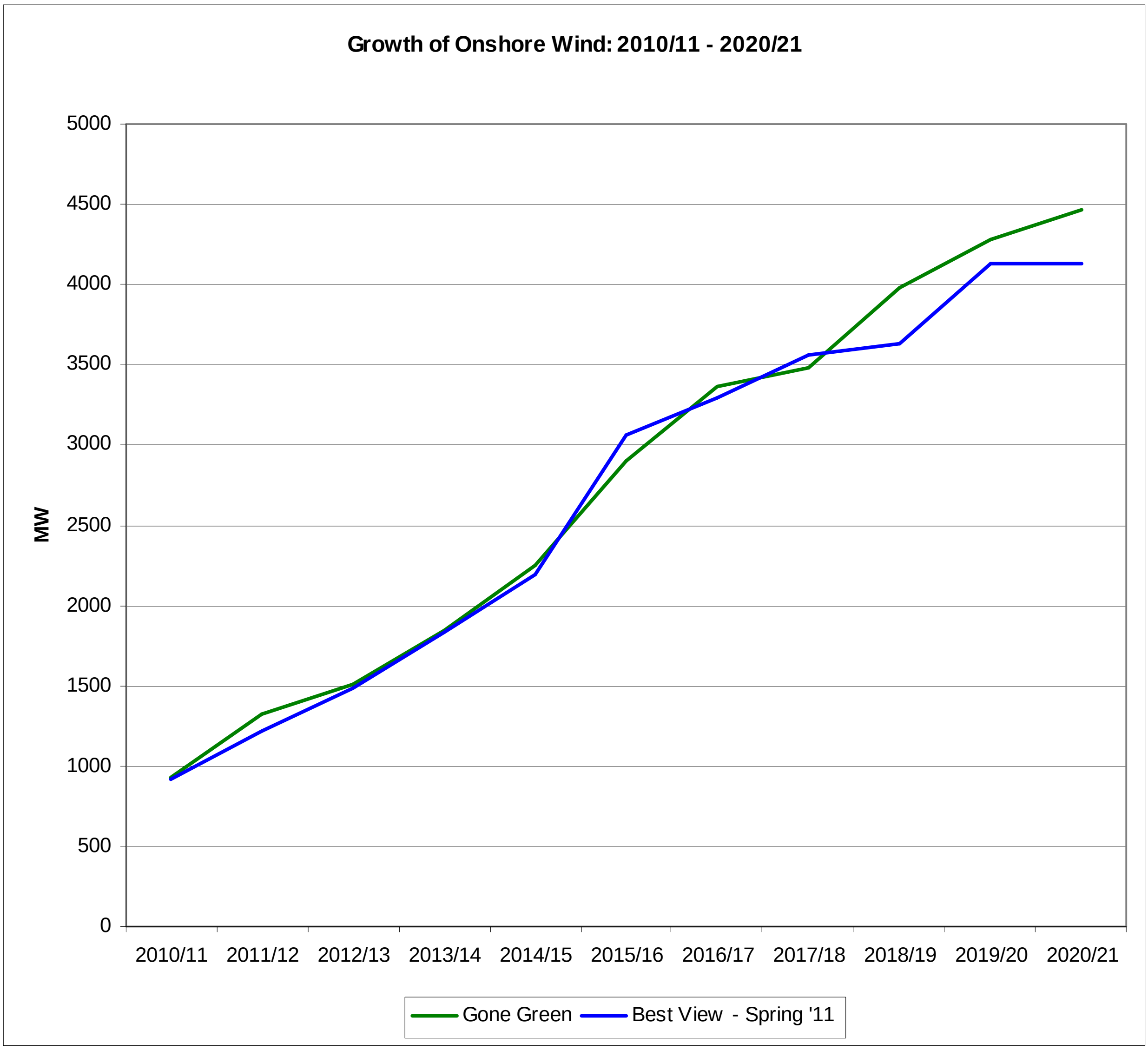
Based on this contracted generation profile in Spring 2011, our central forecast at is that onshore wind generation will rise from a level of around 1GW in 2010 to over 4GW by 2020, and thereafter slow to reach some 5GW by 2030.

Figure 2 also shows the forecast for onshore wind generation in the Gone Green scenario for the north of Scotland, and this is discussed further below. However, it can be seen that the two forecasts are closely aligned, with the relative decrease in contracted generation in the final years of the period reflecting the scarcity of connection agreements for that period at this stage.

An updated version of this Spring 2011 figure is show later, where the increase arising from further applications and agreements between Spring 2011 and the date of this Business Plan are reflected.

Generation scenarios

Figure 2 Onshore renewable – contracted development profile



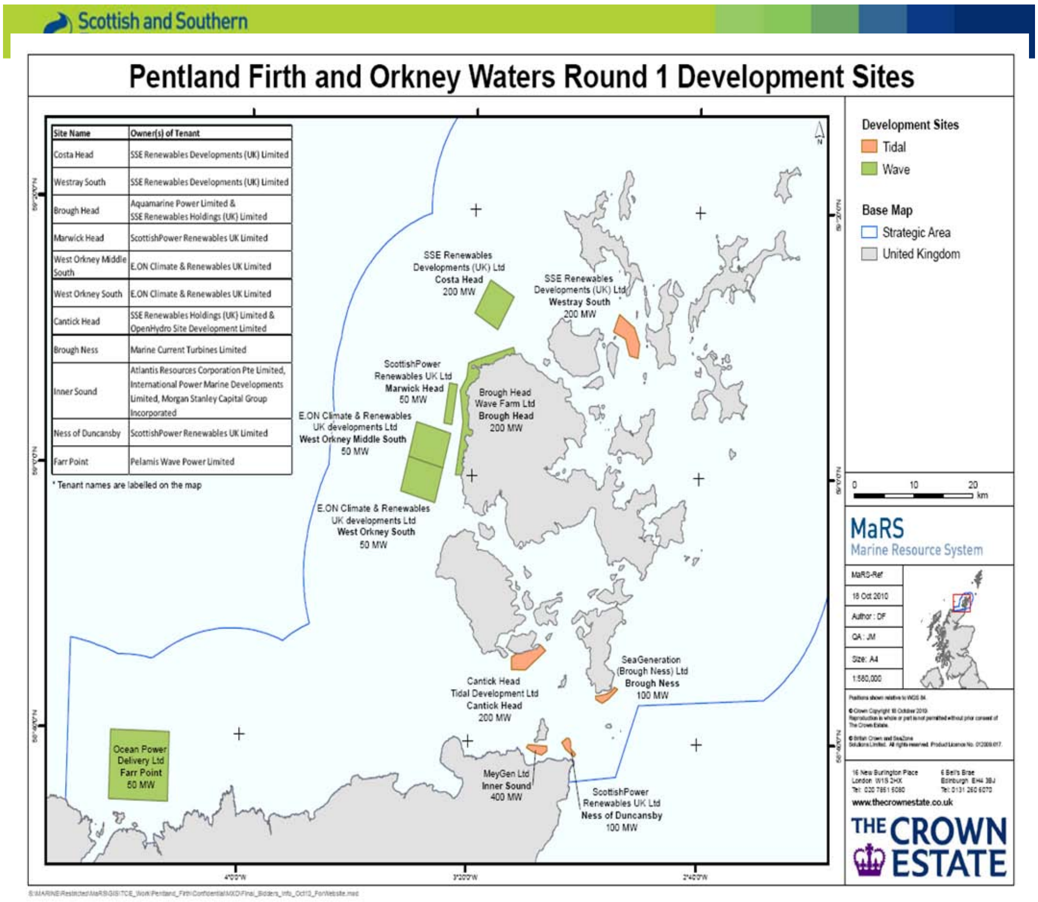
Generation scenarios

Wave and tidal generation

There is currently little marine and tidal generation connected to our network, although we expect this to change within the next decade, with a number of developers now seeking connection terms.

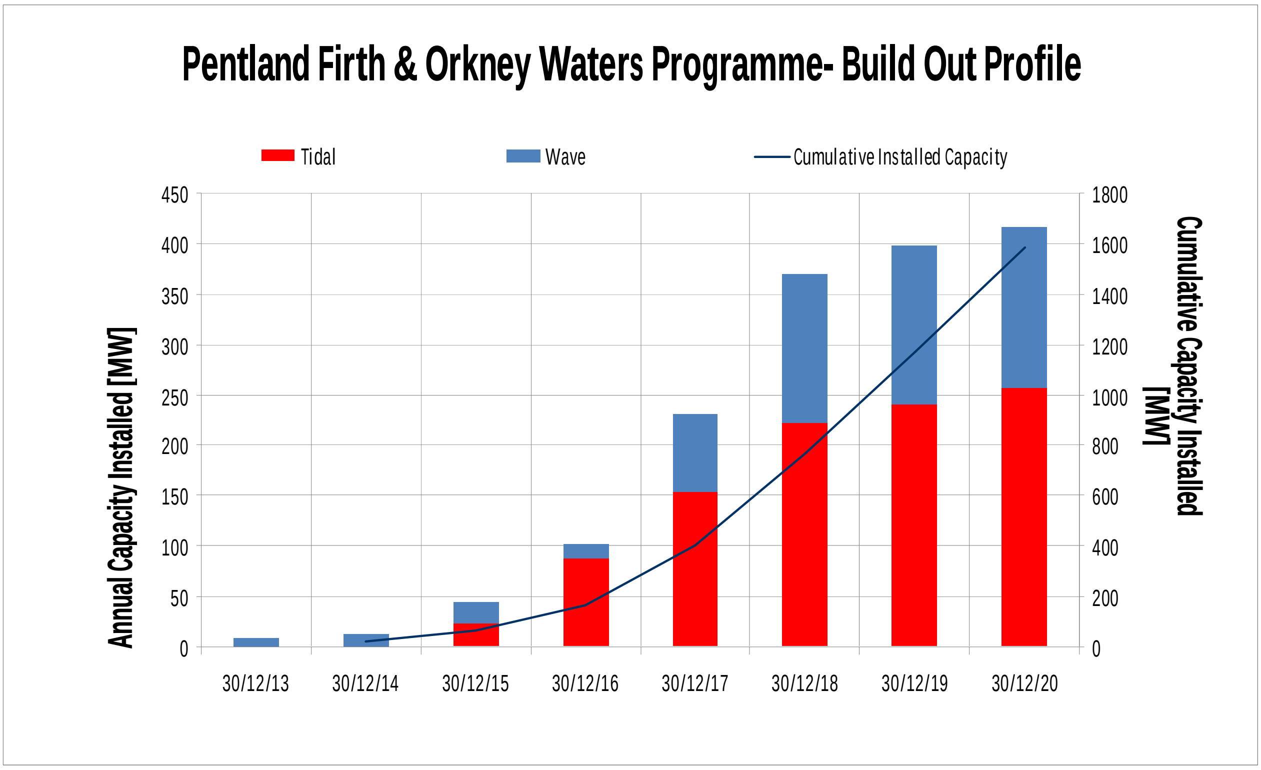
In 2010, the Crown Estate announced a number of agreements with marine renewable developers to allow them to develop projects in the Pentland Firth and Orkney Waters. The agreements indicate a total potential capacity of 1,600MW being phased in time to 2020. Their locations are shown on the map in **Figure 3**, and the build out profile proposed by the Crown Estate is shown in **Figure 4**.

Figure 3 Potential marine developments in Pentland Firth and Orkney Waters



Generation scenarios

Figure 4 Pentland Firth and Orkney Waters programme – build-out profile



In developing our investment plan, we have made a central assumption such that around 35-40% of the potential capacity in the Orkney Waters and Pentland Firth could be constructed within the period to 2020, representing around 600MW, and consistent with the central Gone Green Scenario (see below).

Marine technologies and the areas of deployment around the north of Scotland will significantly influence the timing and scope of future development of the transmission system, not only that currently the subject of Crown Estate leases in the Pentland Firth and Orkney waters, but also on the western seaboard of the Inner and Outer Hebrides, where other marine developments are proposed.

Generation scenarios

We expect to see the planned deployment of smaller scale schemes prior to the establishment of larger schemes.

A summary of the known wave and tidal generation at 2011 is shown in **Figure 5**.

Figure 5 Wave and tidal generation – contracted and prospective

Development		MW	Connect Date	Comments
Pentland Firth & Orkney Waters				
Inner Sound (Stroma)	Tidal	378	From 2015	Contracted for SHETL connection
Duncansby Head	Tidal	95	2016	Offer issued for connection
Costa, Westray and Brough	Wave	450	From 2016	Offer issued for connection
Marwick Head	Wave	50	2016	Contracted for SHETL connection
Balance of 1600MW		627		Awaiting formal applications
West Coast				
Islay Marine	Wave / Tidal	400		Contracted for SHETL connection
Lewis Wave	Wave	40		Offer in preparation

Offshore wind generation

Offshore wind technology is advancing rapidly and the industry is expected to see major and rapid deployment. Around the north of Scotland coastline in areas adjacent to SHETL's licensed area there is potential for several large offshore wind farms.

These comprise:

§ developments within Scottish Territorial Waters (STW);

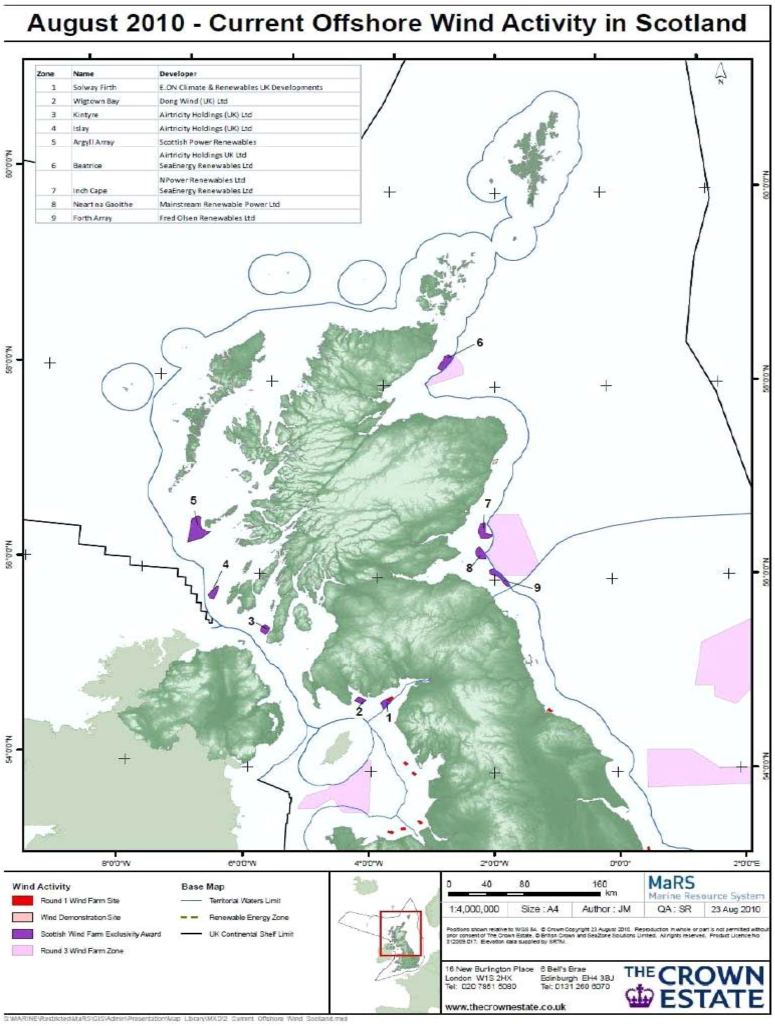
§ developments within the 12 nautical mile limit; and

§ Crown Estate 'Round 3' (R3) development leases which are outside the 12 nautical mile limit.

A summary of the potential developments which may connect into SHETL's transmission network are shown in **Figure 6** and **Figure 7**.

Generation scenarios

Figure 6 Offshore wind activity



Generation scenarios

Figure 7 Offshore wind generation – contracted and prospective

Development		MW	Connect Date	Comments
Moray Firth				
Moray Offshore Wind	R3	1,500	October 2016	Contracted for SHETL connection
Beatrice	STW	1,000	March 2016	Contracted for SHETL connection
Firth of Forth				
Firth of Forth	R3	3,700	June 2015	Contracted via NETSO. First 1GW may connect into Tealing, Dundee. Remaining capacity may connect to Scottish Power.
Inch Cape	STW	900	-	Awaiting application
Western Coastline				
Islay	STW	1000	-	Awaiting application
Kintyre	STW	400	n/a	Not being progressed currently
Argyll Array	STW	1,000	tbc	Likely to connect to Scottish Power area, but with some works on SHETL system

Our central forecast is that offshore wind generation will begin to appear in 2016/17 at an initial level of around 700MW, and rise to around 2.2GW by 2020, and continue to a 2030 level of around 3.6GW.

Further additional offshore wind around the coast of the north of Scotland, perhaps together with increased marine volumes, would require future large HVDC links from these locations to HVDC hub points on the Scottish mainland, with even higher capacity HVDC links taken from these hubs to the north of England.

For the majority of these developments, our initial assumption is that the connection will be either AC or HVDC subsea links, via the Offshore Transmission (OFTO) regime. Under the current offshore transmission regulatory regime, a competitive tender will be run by Ofgem to identify which developers takes the role of OFTO in order to builds these links. Our involvement will be in the provision of the connection from the shore into the existing transmission system, and the reinforcement of the main transmission system which will be required to accommodate the potentially high volume of offshore renewable generation.

Generation scenarios

Demand-side forecasts

While our focus is on new generation schemes, we are also aware of the impact of changing use of electricity on our investment programme. At a high-level, we forecast broadly steady use of electricity in the north of Scotland over the coming decade.

However, developments in 'smartgrid' and smart metering technologies are likely to improve efficiency of electricity usage in the region, potentially shifting times of energy use and storage. Electricity demand might increase, as we move away from a carbon economy, and will have a beneficial effect in utilising locally generated renewable energy, although it is likely to only mitigate the requirement to accommodate increasing power flows to the south of the area.

Establishing generation scenarios – The role of the ENSG

Over recent years a significant number of renewable generation schemes have applied for a connection to our network in the north of Scotland. Since 2005, 900MW has been connected with around 10,000MW currently under construction, consented and in the planning and development process. We also have further active connection offers for new generation and we expect to receive more applications.

Each new scheme requires a new connection to the system and may also need the local network to be extended. The local works necessary to provide a connection between the generator and the transmission system can typically be undertaken at the same time as the generating station is being developed to meet an agreed connection date.

As the number and size of generation schemes in an area increase, they can become the driver for wider reinforcement to the main interconnected transmission system. Such wider system reinforcement can take much longer than local works for the development of generation schemes. Thus, to ensure new wider system capacity is there when it is needed, it is necessary to take a longer-term view in network planning.

Generation scenarios

Longer-term assumptions on the mix, location and timing of future generation connections are initially undertaken on a GB-wide basis.

In recognition of this, in 2008 the Electricity Networks Strategy Group (ENSG) – a cross-industry group jointly chaired by the UK government and Ofgem – asked the three transmission licensees, with support of an industry working group, to develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020.

The Central 'Gone Green' Scenario

The central generation scenario established by the group, known as the 'Gone Green' scenario, comprised existing and forecast generation plant across GB, and made assumptions regarding the volume, timing and location of renewable generation based on known development activity, but adjusted to match the 2020 renewable targets.

This Gone Green scenario was used to identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate such a generation scenario. This work concluded with the publication of 'Our Electricity Transmission Network' in March 2009.

Since then, we, along with the other transmission licensees, have updated and adopted the Gone Green scenario as a key element of our investment planning. This central scenario was also used to develop National Grid's Offshore Development Information Statement, published in September 2010, following a consultation period to determine the most appropriate set of scenarios and testing sensitivities around the Gone Green case.

The current generation assumption in the Gone Green scenario updated in 2011 is shown in summary in **Figure 8**.

During the period of 2010-2020, including the RIIO-T1 period, the dominant renewable technology deploying in the north of Scotland is expected to be onshore wind, with the volume increasing from around 1GW at the start of the decade, and increasing at a rate of 350-400MW annually up to 4.5GW by the end of the decade. Thereafter the rate of onshore wind deployment is forecast to significantly reduce with around 5GW in total connected by 2030.

Generation scenarios

Figure 5.8 ENSG Gone Green generation scenario – Summary for SHETL

Capacity by Sub Fuel Type	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2025/26	2030/31
Gas	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202
Hydro	1,037	1,037	1,085	1,085	1,093	1,093	1,093	1,093	1,093	1,093	1,099	1,099	1,099
Pumped_Storage	300	300	300	300	300	300	300	300	300	300	300	300	300
Offshore Wind	10	10	10	10	10	10	695	795	1,375	1,835	2,235	2,935	3,575
Onshore_Wind	926	1,327	1,513	1,840	2,254	2,901	3,364	3,478	3,982	4,283	4,463	4,773	4,813
Tidal	10	10	10	10	10	29	60	104	180	220	310	830	1,020
Wave	0	0	0	0	0	11	30	56	103	190	260	545	600
Grand Total	**3,485**	**3,886**	**4,121**	**4,447**	**4,868**	**5,545**	**6,743**	**7,027**	**8,234**	**9,122**	**9,868**	**11,683**	**12,608**

Under this central scenario, offshore wind is forecast to arrive around 2016/17 with initial volumes in the Firth of Forth and the Moray Firth. By 2020/21 up to 2GW might be connected to the SHETL transmission system, with around 1GW of which being derived from the northern areas of the Firth of Forth. By 2030, this technology might have increased to some 3.5GW, predominantly from these two offshore areas.

For marine, wave technology is expected to appear in the Pentland Firth and Orkney Waters from 2015, rising gradually to 200-300MW by 2020. Similarly, tidal generation is expected to deploy at demonstration levels for the first few years of the RIIO-T1 period, with a total of 200-300MW also forecast to be installed by 2020 in these waters.

Thereafter, the rate of deployment is forecast to steadily gather pace, with the 1.6GW of marine technology established in the Crown Estate leasings by 2027, consistent with the anticipated resource forecasts for these waters.

Existing plant capacity is forecast to continue throughout the period, comprising the established hydro generation across the north of Scotland, and the generation capacity at Peterhead. No other assumptions have been made regarding the Peterhead infeed to the system of over 1GW, other than to note that Peterhead itself could repower with carbon capture and storage technology, or that an equivalent infeed capacity could be established from interconnector projects with Norway, or farther off-shore generation schemes.

Generation scenarios

Further volumes of generation may be developed, particularly in marine deployment, additional offshore leasings and additional onshore renewable generation in preferred areas. The potential introduction of new pumped storage schemes remains a possibility, but has not been included in the forecasts.

At the end of the RIO-T1 period, in 2020, the total level of connected generation is forecast to have risen by over 6GW from the start of the decade to around 10GW. By 2030, and with the further introduction of offshore and marine technology, this total figure is forecast to have reached 12.7GW.

The 'Slow Progression' Scenario

The ENSG group has also established alternative scenarios – 'Slow Progression' and 'Accelerated Growth' – to test the sensitivity of network development to slower and faster rates of renewable development, not only in Scotland, but also in England and Wales.

For the north of Scotland, 'Slow Progression' is more reflective of a view that there will be consenting effects on onshore wind that will delay some of the projects whilst others will either reduce in output or fail to proceed. This scenario might also reflect uncertainties in the investment environment for renewables in GB, arising from some combination of a weak economic climate, ongoing renewable support mechanisms and unfavourable charging regimes for use of the GB transmission system.

Deployment of onshore wind will continue over the decade, albeit at a slower rate of around 250-300MW annually, compared to the 350-400MW rate in the central Gone Green scenario. By 2020, 4GW of onshore generation is being approached, and thereafter deployment is forecast to reduce further with around 4.3GW connected by 2030.

Technology and environmental hurdles are assumed to delay the deployment of offshore wind and marine renewables, with a longer deployment phasing of a much-reduced volume. Under this scenario, offshore wind is forecast only to establish 550MW by 2020, with a further 500MW added by 2025, and a total of 1.6GW by 2030.

Wave and tidal marine generation is forecast to perform particularly poorly up to 2025, under this scenario, with levels only rising from 2025 to some 600MW by 2030. This generation is assumed to be almost exclusively in the Pentland Firth and Orkney Waters, under the Crown Estate leasings.

Generation scenarios

The current generation assumption in the Slow Progression scenario is shown in **Figure 9**.

The 'Accelerated Growth' Scenario

In the Accelerated Growth scenario, the assumptions regarding the potential growth in renewable generation are significantly more positive. There is a presumption that onshore deployment continues in line with the central Gone Green scenario, but that consenting effects and technology hurdles are far more easily overcome for offshore and marine technologies. The background climate is presumed to be significantly more favourable for general investment and, in particular, in support of renewable generation.

This scenario is also consistent with the Scottish Government's target for the provision of renewable energy in Scotland, with a new target set in spring 2011 for 100% of Scotland's electricity energy demand to be sourced from renewable energy generation.

As with the central case, the dominant renewable technology deploying in the north of Scotland through to 2020 is expected to be onshore wind, with the volume increasing to some 4.5GW by the end of the decade, and thereafter to 5GW by 2030.

Offshore wind is forecast to establish rapidly with the first 1GW in place by 2015, across the Firth of Forth and the Moray Firth. By 2020, some 3.6GW is forecast, including 2.5GW in the Moray Firth. By 2030, this technology might have increased to over 4GW, predominantly from these two offshore areas, although significant volumes of generation could also be expected in the waters of the Inner Hebrides, with a number of sites under initial investigation by developers.

For marine, wave and tidal technology are forecast to appear in the Pentland Firth and Orkney Waters from 2015, similar to the central Gone Green scenario, but to rise at a faster rate to 2020. Wave technology is forecast to increase to 500MW by 2020, then 600MW by 2030. Tidal technology is forecast to rise to 650MW by 2020, and continue to be deployed to a total of 1000MW by 2030. The 1.6GW of total marine resource anticipated for these waters by the Crown Estate are achieved around 2023/24, compared with 2027 in the central scenario.

The current generation assumption in the Accelerated Growth Slow Progression scenario is shown in **Figure 10**.

Generation scenarios

Figure 9 ENSG Slow Progression generation scenario – Summary

Slow Progression													
Capacity by Fuel Type	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2025/26**	**2030/31**
Gas	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202
Hydro	1,037	1,037	1,085	1,085	1,093	1,093	1,093	1,093	1,093	1,093	1,099	1,099	1,099
Pumped_Storage	300	300	300	300	300	300	300	300	300	300	300	300	300
Offshore Wind	10	10	10	10	10	10	10	10	555	555	555	1,045	1,645
Onshore_Wind	926	1,327	1,513	1,728	1,987	2,275	2,643	2,890	3,348	3,759	3,909	4,237	4,302
Tidal	10	10	10	10	10	10	10	10	10	10	10	60	370
Wave	0	0	0	0	0	0	0	0	0	0	0	25	250
Grand Total	**3,485**	**3,886**	**4,120**	**4,335**	**4,602**	**4,890**	**5,258**	**5,505**	**6,508**	**6,919**	**7,075**	**7,968**	**9,168**

Figure 10 ENSG Accelerated Growth generation scenario – Summary

Accelerated Growth													
Capacity by Fuel Type	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2025/26**	**2030/31**
Gas	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202	1,202
Hydro	1,037	1,037	1,085	1,085	1,093	1,093	1,093	1,093	1,093	1,093	1,099	1,099	1,099
Pumped Storage	300	300	300	300	300	300	300	300	300	300	300	300	300
Offshore Wind	10	10	10	10	110	1,305	2,385	2,675	2,855	3,215	3,575	3,875	4,175
Onshore Wind	926	1,327	1,513	1,840	2,254	2,901	3,364	3,478	3,982	4,283	4,463	4,773	4,813
Tidal	10	10	10	10	10	45	90	160	370	520	670	1,020	1,020
Wave	0	0	0	0	0	20	45	90	200	380	500	600	600
Grand Total	**3,485**	**3,886**	**4,121**	**4,447**	**4,968**	**6,865**	**8,478**	**8,997**	**10,001**	**10,992**	**11,808**	**12,868**	**13,208**

Generation scenarios

Summary of the three ENSG generation scenarios

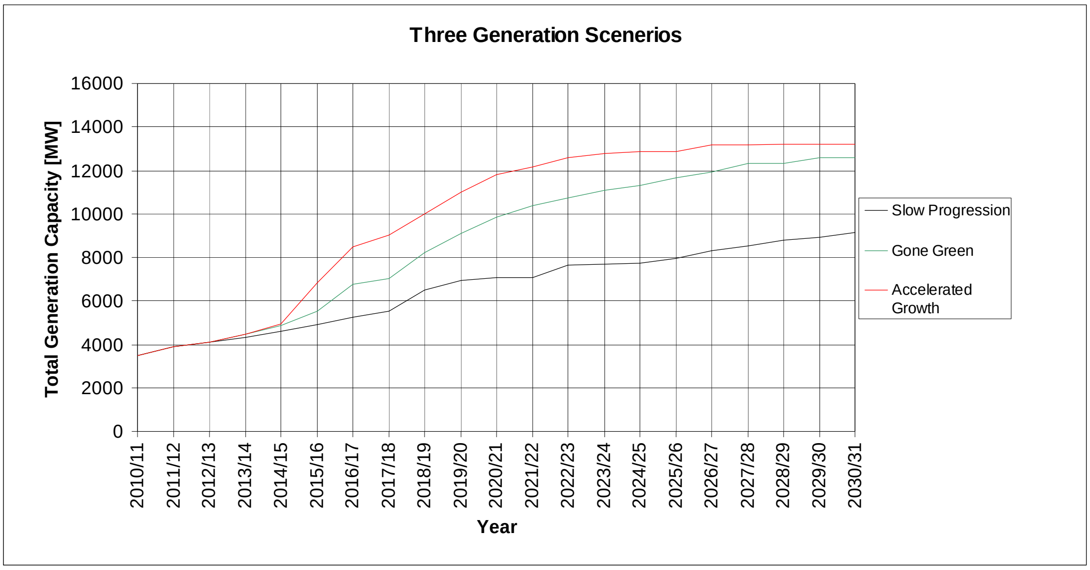
For the north of Scotland, the graph in Figure 11 shows the generation volume forecasts for the three ENSG scenarios.

Whilst the Gone Green and Accelerated Growth scenarios develop at different rates, they achieve a similar total level of generation by 2030 at around 12.6-13.0GW, of which the renewable generation volumes are around 11.4-12.0GW. However, by 2020, the difference is more marked with the Accelerated Growth scenario seeing an additional 2GW of renewables established above the 8.6GW in the central case. 1.4GW of this difference is attributable to offshore wind, with the balance of 0.6GW attributed to marine generation.

By contrast, the slower 'Slow Progression' case falls short of the central case by some 3GW at both 2020 and 2030, with contributions across all technologies.

At the end of the RIIO-T1 period, in 2020, the volume spread in renewable generation is almost 5GW, with 5.8GW in the lower case, and 10.6GW in the upper case.

Figure 11 The three ENSG generation scenarios



Generation scenarios

The variation of generation volumes in the three ENSG scenarios serves to demonstrate that there remains considerable uncertainty going forward on the absolute requirement and timing for a specific development project on the main interconnected system. Similarly, the requirement to provide connection and local infrastructure works for individual renewable schemes will remain uncertain whilst the developer is in the early stages of survey and consenting of his project. This is consistent with what our stakeholders have told us.

SHETL's Best View

The ENSG scenarios have been a very important stage in setting a high-level vision for the planning of our network to meet our national renewable generation targets.

Account then needs to be taken of local investment planning needs. Within our own geographic area, the volume, location and timing of onshore renewable technologies, marine and offshore wind generation are key influencing factors for developing our investment plan.

Using the Gone Green scenario as a starting point, we have then refined our central (SHETL 'Best View') generation scenario and associated investment plans based on the contracted position for connections, and in particular for onshore wind, and the expected requirements of individual and regional groups of users.

The updated Gone Green scenario, and its associated Slow Progression and Accelerated Growth outlying scenarios were established and set in April 2011, and a number of developments have taken place since that time, and some of those will continue to change. These include:

- Offers for connection of onshore wind schemes which were previously based on an outline position of a connection in 2018 have been converted to firm offers with specified connection dates. The majority of these offers allowed for connection dates earlier than 2018, arising from 'Connect & Manage' principles.

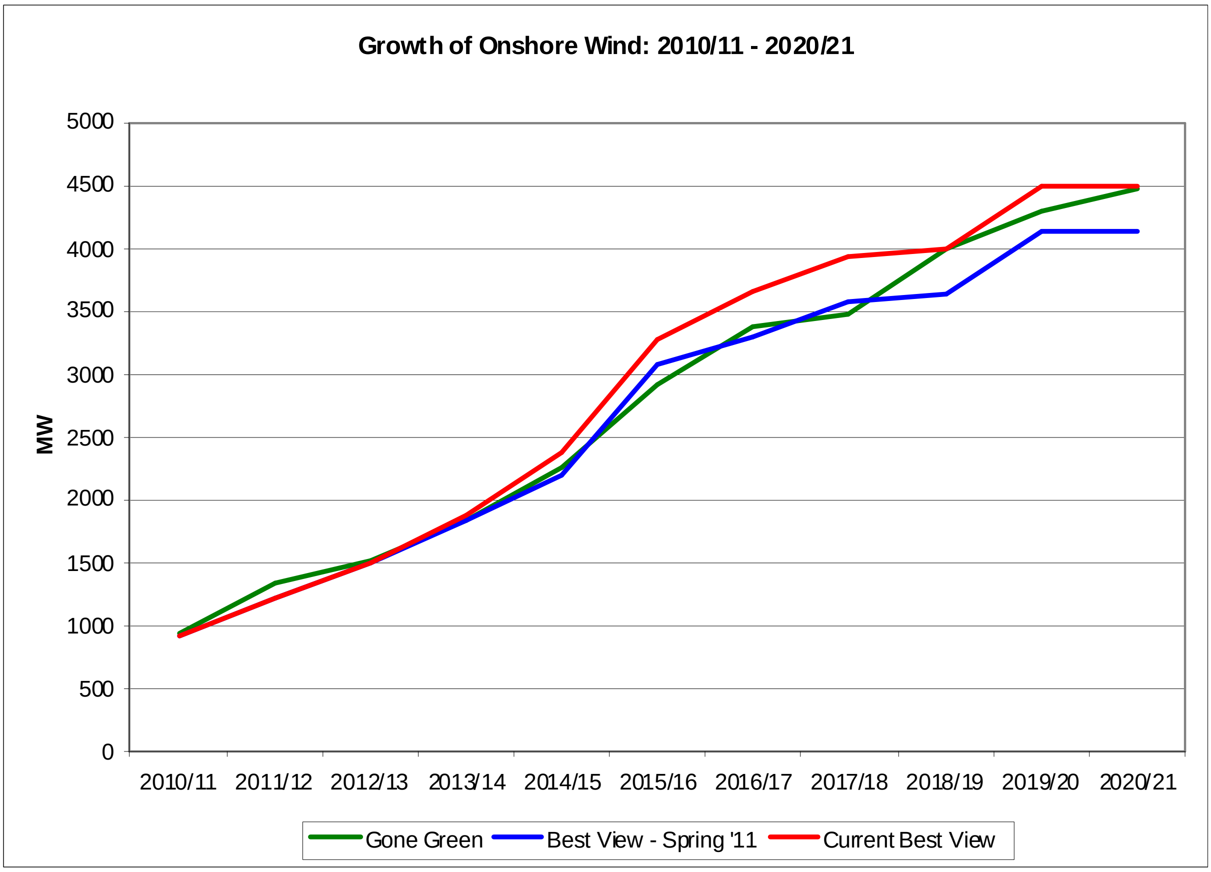
- Changes to contracted capacity for specific generation schemes where planning applications or consents indicated the likelihood of a, usually, lower permitted capacity, or where termination of connection agreements are foreseen.

Generation scenarios

§ The making of connection offers and the signing of new connection agreements with onshore wind and marine projects, since the establishment of the updated Gone Green scenarios in April 2011.

Figure 2 showed a comparison of the anticipated connection profile based on some 4.5GW of contracted onshore generation in Spring 2011. An updated version of this figure is show below (Figure 12), where the increase arising from further applications and agreements between Spring 2011and the date of this Business Plan are reflected.

Figure 12 Comparison of the Gone Green profile and the current SHETL Best View for onshore renewables



Generation scenarios

Figure 12 shows a comparison of the Gone Green profile for onshore renewable (largely wind) generation and the updated position taking these subsequent changes into account. A further 350MW of generation have been added to the contracted position. The figure shows that the SHETL Best View has a marginally increased capacity profile over the RIIO-T1 period, compared to the Gone Green scenario, driven by the above changes.

- Our best view in our central forecast is that onshore wind generation will rise to a level of around 4.5GW by 2020.

- For offshore wind generation, our central forecast is that windfarms will begin to appear in 2016/17 at an initial level of around 700MW, and rise to around 2.2GW by 2020, and continue to a level of around 3.6GW by 2030.

- For marine generation, our central assumption is that around 35-40% of the potential capacity in the Orkney Waters and Pentland Firth could be constructed within the period to 2020, representing around 600MW, and consistent with the central Gone Green Scenario.

As these levels are broadly consistent with the ENSG Gone Green scenario, they are also at levels which would meet UK Government targets.

The Scottish Government's target for the provision of renewable energy in Scotland, with a target for 100% of Scotland's electricity energy demand to be sourced from renewable energy generation by 2020 is more challenging.

It is more aligned with the ENSG Accelerated Growth scenario, for which the following volumes are forecast:

- Onshore wind 4.5GW – as per the central case.
- Offshore wind 3.6GW – including 2.5GW in the Moray Firth.
- Marine 1.6GW by 2023/24.

Thus our central case would not meet the Scottish Government's target; however our upper case would meet the target. In this regard it is important to note that our Business Plan is designed to 'flex' to meet the actual requirements of generators as and when they come forward.

Connection works

In this section we describe the processes involved in the provision of new connections.

Three main types of connection exist:

§ Connection of new demand or modification to an existing demand to the transmission network. This might also include infrastructure investment to maintain compliance with standards.

§ Connection of new generation scheme to the transmission network or modification to a generation scheme already connected. Again this might also include infrastructure investment to maintain compliance with standards.

§ Upgrading of existing Grid Supply Points (GSPs) to accommodate the increases in embedded generation connected to the Distribution Network Operators (DNOs) system.

Application of the connections process

Renewable generation projects come in the full range of sizes.

§ Small schemes, under 1MW, connect into the local distribution system generally without any dependency on works on the transmission system.

§ Schemes larger than 1MW may connect onto the local 33kV distribution system; however an assessment is made of the impact of the scheme on the transmission system ("Statement of Works").

§ Significantly larger schemes will directly onto the transmission network.

Applications for connection are made by the developer to National Grid either directly or, where the generation will be connected to the distribution network, via the DNO. National Grid then requests SHETL to design and quote for the necessary transmission works to provide, or upgrade, the connection and any local and wider infrastructure.

Connection works

The connection offer

There are a series of terms referred to by ourselves and National Grid to identify what type of infrastructure is required to allow a new generation or demand connection to become connected to the existing transmission system.

A summary of these terms is given below:

Connection assets Plant, normally the main transformer and associated lower voltage equipment up to the point of connection, which are funded by the user through capital contributions or by electing to pay annual charges for use of the asset via National Grid.

Sole-use enabling infrastructure Local system infrastructure which is being developed, designed and built solely for the benefit of the user making the application and requiring this to connect to the existing transmission system. This is not paid for upfront, but through annual Transmission Network Use of System (TNUoS) charges.

Shared-use enabling infrastructure Local system infrastructure which is being newly developed and built for the benefit of multiple applicants, or which is existing infrastructure being upgraded to accommodate new applicants in addition to existing users, effectively triggering the requirement for an increase in capability on the existing system. Again this is paid for through TNUoS charges.

Wider works (or main interconnected transmission system (MITS) infrastructure) When the main transmission system requires a significant change required to meet the network capacity requirements of one or more new users, such as a group of renewable generators. Again this is paid for through TNUoS charges.

Generally assets subsequently paid for through TNUoS charges will be underwritten by the applicant during construction. We note that this, and TNUoS charges in general, are currently subject to review under the TransmiT project being consulted on by Ofgem.

Works necessary for connection

Historically, new connections have been subject to the completion of all necessary upgrade works on the local and wider transmission system.

However, with the introduction of the “Connect & Manage” approach to access to the system, this contingency has been relaxed. Now, subject to some

Connection works

checks and balances, generator connections are made before the completion of the wider works. The potential consequence of this is system constraints until the wider works are completed. National Grid, as system operator, is responsible for active management of overall power flows and system constraints. Connections are still contingent on the completion of the necessary local infrastructure and connection works.

With Connect & Manage in place, developers now have more certainty regarding their access to the system. Developers with consented projects are able to request earlier connect dates than previously possible, and are able to confirm costs and establishing new project timescales for their connection. Developers awaiting project consents are able to indicate a future connection date, knowing that access to the system is dependent only upon the local connection and infrastructure works.
It is essential that good communication exists throughout the connections process between the developer, National Grid and us, with frequent engagement in all aspects of such projects to ensure realistic timescales are set and managed for all parties.

SHETL welcomes any developer wishing to seek a connection onto our network to discuss their project with us as early as possible in their process to ensure that all parties can gain a realistic understanding of the possible connection solutions, timescales and costs.

New developers may be unfamiliar with the connection process, and we are most happy to assist in their understanding in order to achieve a successful completion. We believe that the more collaborative working we are able to do together, with related stakeholders, the better chance there is for a successful outcome for all involved.

Our plans to improve our service around new generator connections are described in our supporting document **Future standards of customer service**.

Connection works

Our approach to designing new transmission connections

Over the recent years the increasing volume of new connection requests for renewable generation has been a significant focus for us.

To assist in the process of designing and quoting for connections, following developer applications to National Grid, we have established standard designs which have improved our efficiency in identifying accurate costs and timescales for their delivery.

While in general we continue to propose the lowest cost solutions to meet the needs of the developer, we are often asked to consider and propose alternative more expensive solutions, which can deliver an earlier completion date. An example would be where an underground cable route through, or around, an environmentally-sensitive site would be granted more readily than an overhead solution. This option can be offered, with the developer accepting the difference in costs.

Schemes are fully costed at the detailed design stage, based on comprehensive information sourced from recently completed schemes of the same designs and our framework contracts.

Our procurement process has established five year framework contracts, utilising multiple equipment suppliers and construction companies to provide us with sufficient staff and resources for completion of this programme of projects, as the volumes of projects increase per annum.

There are also benefits in this standardisation when working with developers, planning authorities and landowners as it provides a consistent approach which can significantly reduce the timescales in gaining the necessary approvals from all interested parties.

The volume of new connections in the pipeline has created a more fluid programme of work than ever, which becomes very difficult to quantify with any certainty. We continuously review this situation, in conjunction with National Grid, to ensure that the users commitment is still contracted and not withdrawn. However, with understandable uncertainty on the generator side over the development timescale, we need to be extremely flexible in our approach to delivering generator connections.

This makes the task of predicting the required expenditure, resources and supply chain needs very difficult for the duration of the RIIO-T1 period. Our contracted schemes extend to 2018, but not beyond.

Connection works

SHETL is confident that it can continue to deliver connections within agreed timescales during RIIO-T1. The variety and complexity of our network, together with the volume of new connections making requests does present issues in ensuring these measures are realistic – not least as each project has different requirements and there is no simple single solution fits all. Ensuring we have the necessary resources to carry out this initial work is key to assisting us in achieving this.

For example, we have seen over the past four years around five new 132kV substation connections to the network annually. Over the next period this is likely to grow to between eight and 12 which include several higher voltage connections at 275kV. There is also the potential of 400kV sites once this network voltage becomes available for connection to our system.

It is important that we have the necessary funding mechanisms in place to allow us to develop the network to meet these changing requirements, which can not be fully quantified at present.

About the funding of new connections

Overview

The following section sets out our approach to funding less certain sole-use and shared-use connection infrastructure that comes forward during the RIIO-T1 period.

The need for connection assets and infrastructure over the period is a function of the generation that comes forward. There is therefore uncertainty over the level of connection assets and infrastructure required.

In order to accommodate this uncertainty, we have set out our requirement for two revenue drivers over the RIIO-T1 period: one to finance less certain sole-use infrastructure; the second to finance shared-use infrastructure.

Generation scenarios

The modification of the Gone Green scenario into the SHETL Best View described above shows only slight changes to the profile.

However, before we can set an appropriate funding mechanism, account then needs to be taken of the potential success rate of the individual generation schemes being fully developed, gaining consents, meeting consenting conditions, commercial viability and project financing in order to materialise as a fully developed renewable generation scheme requiring a grid connection and access to the transmission system.

Clearly, there is uncertainty in forecasting both the volume of generation schemes and MW capacity that will reach such maturity, and in also identifying the specific projects to inform specific grid connection requirements and the location of transmission investment.

About the funding of new connections

The 'Slow Progression' scenario indicates some 2,900MW of new renewable generation in the period, giving a total of wind and marine generation of 4,450MW by 2020. By comparison, the central 'Gone Green' scenario indicates 5,700MW of new renewable generation in the period, with a total of wind and marine generation of 7,200MW by 2020.

On this basis, for the central case, we have assumed that 85% of the prospective investment in connection and local sole-use infrastructure will be required in the period. Variations above and below this level will be covered by the revenue driver mechanism described below.

For the local shared-use infrastructure, we have taken an assumption that up to 50% of the investment will be required in the central case. Again, variations above and below this level will be covered by a revenue driver mechanism which is specific to this category of infrastructure investment.

Scope of the revenue driver

For the purposes of the revenue driver, it is important that we clearly define the 'boundaries' to which the revenue driver (or drivers) applies.

We define local enabling works as incorporating:

§ local connection assets (for transmission-connected generation);
§ sole-use enabling infrastructure; and
§ shared-use enabling infrastructure.

These works facilitate or 'enable' the connection of new generation sites to the existing transmission network.

The **local connection assets** are those assets that are necessary to connect the customer's assets to the transmission infrastructure. The exact definition of local connection assets varies depending upon the type of connection.

For example, where the customer requires a double busbar-type connection, the local connection assets are those assets that connect the customer's assets to our substation. For teed or mesh connections, it is those assets that connect the customer's assets to the HV disconnector, or an equivalent point of isolation. These assets are new, single user assets

About the funding of new connections

and, as such, are paid for in full by the customer, either through an upfront payment or an annuitized payment over a period of years. As such, they sit outside of the revenue driver mechanism.

Beyond the local connection assets, work is required to connect the local connection assets to the existing transmission network. The extent of these works will depend on the generator's location. As with the local connection assets, this infrastructure will tend to be triggered by the connecting party and be for his sole-use. However, unlike local connection assets, **sole-use enabling infrastructure**, once constructed is funded through the price control mechanism.

Beyond any sole-use infrastructure, any works required to reinforce (or rebuild) the network to accommodate the new connection are referred to as **shared-use enabling infrastructure**. More often than not, this infrastructure already exists and serves other users of our network.

Shared-use enabling infrastructure is separate from wider (MITS) infrastructure. Later in this document, we set out that large capital projects that meet or exceed a threshold of £50 million fall within a different funding mechanism. They are therefore outside of the revenue driver mechanism that is set out here.

Funding mechanism

In terms of sole-use enabling infrastructure, uncertainty over the extent of this infrastructure as a result of future generation connections is currently accommodated through a SHETL-specific revenue driver. We support the ongoing use of a revenue driver to manage / accommodate this uncertainty in the RIIO-T1 period and we set out our best view of this mechanism below.

In terms of shared-use enabling infrastructure, we believe it is also appropriate to accommodate uncertainty in future demand for this infrastructure through a revenue driver mechanism.

To this end, and given the breakdown of likely projects, we believe it is necessary to develop a second and separate revenue driver to that used for sole-use infrastructure.

Ex ante allowance

However, before discussing the detail of our proposed revenue drivers, it is worth first setting out our approach to **the more certain** sole-use and shared-use infrastructure local connection work forecast to come forward during the RIIO-T1 period.

About the funding of new connections

We have identified a subset of connection projects to which an *ex ante* allowance will apply. As described above, this equates to 60% of our total forecast expenditure in relation to sole-use infrastructure and 30% in respect of shared-use infrastructure (£150 million and £100 million respectively).

In return for this *ex ante* allowance, we will deliver 1,258 MW and 1,096 MVA of sole-use and shared-use capacity associated with generation respectively, with any efficient over or underspend against this allowance being subject to the base capex sharing factor of 30% (see the supporting document **Determining our allowed revenue**). Only once the respective capacities have been delivered, will the revenue driver mechanism apply. The detail of this mechanism is set out below.

Revenue driver mechanism

In order to establish the correct level for the respective revenue drivers, we have looked at known connection projects during the RIIO-T1 period and assessed the total cost of delivering these projects against the generator's original capacity request for sole-use infrastructure (MW) and the delivered capacity (MVA) for shared-use infrastructure. This excludes any diversity over the projects that will come forward, which might have been applied elsewhere.

Our analysis is shown in Table 1 and Table 2 overleaf.

The use of MVA is necessary when it comes to understanding the impact of shared-use infrastructure local connection work, which will commonly reinforce the existing system and not be directly associated with any connecting generation.

In relation to sole-use infrastructure, MWs connected is a function of the generation that ultimately connects and does not necessarily have a direct correlation to our role in providing the generator's originally requested capacity. We therefore believe it is more appropriate to base the revenue driver on the generator's original capacity request; in this way, we are not exposed to the costs of providing infrastructure, which the generator does not ultimately use in line with its request. The alternative to this approach would be to apply an uplift of 20% to the proposed revenue driver rate to address this issue.

Only once the respective MW / MVA triggers have been reached, will the revenue driver mechanism apply. This is akin to the current TPCR4 mechanism.

About the funding of new connections

Table 1 Sole use infrastructure

'Scheme'	Designed connection capacity (MW)	Forecast scheme cost (£m)	UCA (£k/MW)
1	234	12.0	51
2	226	28.5	126
3	180	26.2	146
4	150	5.8	38
5	150	30.3	202
6	114	5.1	45
7	113	2.0	18
8	99	8.9	90
9	93	5.3	57
10	90	4.0	45
11	81	47.4	586
12	80	10.7	133
13	75	17.7	236
14	73	2.1	29
15	69	6.2	89
16	60	0.6	10
17	50	7.3	146
18	50	11.0	221
19	43	11.5	268
20	41	0.1	3
21	26	6.9	265
Total	**2,097**	**250**	**-**
Average	**-**	**-**	**119**

Table 2 Shared use infrastructure

Scheme	Delivered MVA	Forecast scheme cost (£m)	UCA (£k/MVA)
Keith- Tomatin	806	68.5	85.0
Beauly-Tomatin	622	52.9	85.1
Inverary-Crossaig	466	58.5	125.6
Taynuilt-Inveraray	466	27.6	59.3
Knocknagael-Foyers	420	18.5	43.9
Fort Augustus-Fort William	333	42.7	128.3
Dounreay-Gills Bay 132 kV	300	54.6	182.0
North Argyll-Dalmally	240	8.3	34.6
Total	**3,653**	**332**	**-**
Average	**-**	**-**	**91**

About the funding of new connections

As at TPCR4, the revenue drivers would comprise two elements: an element of pass-through of actual costs incurred and a unit cost allowance (UCA) realised on project completion. To this end, our proposed revenue drivers (one for sole use infrastructure, one for shared use infrastructure) both extend the current TPCR4 funding arrangements of 75% cost pass through of incurred costs upfront, with the remaining 25% being funded through the UCA on delivery. Because the UCA would be made in arrears, the mechanism would incorporate an element of financing costs.

Our proposals also include 100% pass through arrangements for projects above a certain threshold, so-called ‘high cost projects’.

This is because the inclusion of these high cost projects in the calculation of the UCA skews the UCA upwards to the disbenefit of consumers. Cost pass through can lend protection to consumers. We see this both in relation to high cost projects, where the inclusion of these projects in the revenue driver calculation could potentially result in higher costs to consumers depending on which projects actually outturn in the price control period, and, more generally, in relation to forecast costs that outturn to be substantially lower. It also reflects the uncertainty that is inherent in this type of work, particularly when forecasting across an eight-year price control.

High cost projects arguably have the greatest degree of uncertainty and are very difficult to ‘shoe horn’ into a generic mechanism. Therefore, a pass through approach is the most appropriate and realistic and ensures that the resulting UCA is more reflective of each project within the revenue driver ‘pool’. We would only expect one or two projects to fall within the high cost category. For sole-use infrastructure, we have set a threshold of £250 k/MW; for shared-use infrastructure, we believe the threshold should be £150 k/MVA. Projects falling above this threshold are excluded from the UCA calculation, the components of which are set out above.

Revenue Driver parameters

In 2009/10 prices we require a UCA of £95 k/MW for sole-use infrastructure and £83 k/MVA for shared-use infrastructure. It is important that as we go through the RIIO-T1 period, these costs are updated to reflect inflation.

Our funding proposal is set out in Figure 13.

About the funding of new connections

Figure 13 Overview of funding for new Connections (2009/10 prices)

Infrastructure	Ex ante allowance		Revenue driver	
	Cost allowance	Capacity	Unit cost allowance	High cost project threshold
Sole-use	£150 million	1,258 MW	£95 k/MW	£250 k/MW
Shared-use	£100 million	1,096 MVA	£83 k/MVA	£150 k/MVA

Strengthening our transmission system

This section provides detail on the programme of large capital projects which is likely to be required over the RIIO-T1 period and beyond. It discusses the prospective timelines and costs of projects, our approach to dealing with the uncertainties associated with individual projects and in the delivery of the overall programme, and the proposal for undertaking design and pre-construction works.

Included in this section are:

- § Proposed and prospective projects
- § Our SHETL 'Best Estimate'
- § Getting the timing right

What our stakeholders have told us

Stakeholder comments have reinforced our views on the uncertainty around the delivery of wider system reinforcements. A range of factors that we need to take into account were highlighted.

Recognising the wide range of project uncertainties in the approach to the regulatory funding of the projects is critical to us. Over the next decade, we could invest some £3-5 billion in our network compared to the value of the existing business of around £450 million.

This unprecedented growth would present new and very real business challenges. Against this background, it is our view that we should minimise customers' and our own risk over this growth period.

On **timely investment**, stakeholders welcome the proposals for the improvements in transmission infrastructure in the north of Scotland, as this is seen as an essential step in the enabling economic development based on the new renewable generation capacity anticipated in the area in the next ten years and beyond.

One stakeholder said:

"The availability of grid connections in the area will be key in firstly securing finance and later in the build out of new onshore and offshore wind and wave and tidal generation in the area."

A further stakeholder responded:

"SHETL's proactive approach to facilitating transmission development in a challenging and heavily regulated environment is welcomed given the level of uncertainty in the electricity market due to the breadth and depth of fundamental review of transmission charging, underwriting and market arrangements. Taking each proposal on a case by case basis, identifying uncertainties, adopting a robust engineering approach underpinned by evidence is the best way forward, and at this point in time seems to be a common sense approach and one that offers the most robust opportunity for project development and management."

On **anticipatory/strategic investment** some responses supported making anticipatory or strategic investments in transmission networks so that generation connections can be delivered when generation is ready. Such early investment in the transmission system, ahead of a demonstrated needs case is considered essential for the UK to make the transition to a low carbon economy and to achieve 2020 objectives.

The view expressed by some stakeholders is that, if not addressed early, onshore transmission issues could be a bottle neck for offshore renewable connections due to the significant planning and consenting timescales for such onshore work. A similar view suggested consideration of a mechanism that allowed SHETL to strategically invest in their transmission network.

However, there was also support for continuing the current regulatory framework along the lines of the Transmission Investment and Incentives (TII) mechanism for gaining regulatory funding for large capital projects, whilst uncertainties exist in respect of the regional generation growth rates, and the scope, costs, consenting and timings of the transmission development.

As part of this framework, there was support for the principle of progressing pre-construction (design and consenting) funding for potential transmission infrastructure developments, in order to optimise construction readiness with confirmed need, and avoid undue delay.

The proposed and prospective projects that might be required to accommodate renewables

For the north of Scotland, the volume, location and timing of onshore renewable technologies, marine and offshore wind generation are key influencing factors for developing our investment plan.

As described above, we have taken the 'Gone Green' scenario established for the national ENSG study as a starting point for informing our investment requirements. We have then looked at the evidence within our area of future generation connections, and refined our investment plans based on the contracted position for connections and the expected

Strengthening our transmission system

requirements of individual and regional groups of users.

From this, we have developed proposals for a number of major transmission reinforcements that progressively allow connection of an increasing volume of renewable generation to the MITS.

The basis for our analysis is the existing transmission system and those reinforcements which are recently completed or currently under construction:

§ A new 275/132kV substation at **Inverarnan**, near Sloy beside Loch Lomond, to support renewable generation growth in Kintyre, Argyll and Bute;

§ The replacement **Beauly-Denny** 400kV overhead line and associated substations that will facilitate the connection of 1.5GW of renewable generation;

§ A new 275/132kV substation at **Knocknagael**, near Inverness, that will provide transmission capacity for additional renewable generation in the far northwest, prior to the completion of the Beauly-Denny upgrade;

§ The reconductoring of the existing 275kV overhead line between **Beauly, Blackhillock and Kintore** to allow for the connection of an additional 850MW of renewable generation;

§ The installation of a second 275kV circuit on the existing overhead tower line between **Beauly and Dounreay** and the upgrades of the existing Beauly and Dounreay grid substations to allow the connection of an additional 400MW of renewable generation in the Caithness-Sutherland area; and

§ The replacement and upgrading of the **Beauly-Mossford** 132kV overhead lines with a double-circuit 132kV line and a new 132kV switching station near Mossford to provide transmission connection and access for renewable generation in the Strathconon and Strath Bran area.

The total cost of these projects is around £800 million which we are investing between 2006 and 2015.

From this base, we have identified further projects that are likely to be required in order to connect and support the forecast growth in renewable generation. These projects would accommodate further onshore wind, new offshore wind and marine generation. They include potential links to the main island groups. Taken together these network upgrades would provide increased transmission capacity for the export of this power to the southern demand centres.

In total, these schemes represent the majority of our capital expenditure investment requirements over the next decade to 2020, and our main focus is getting

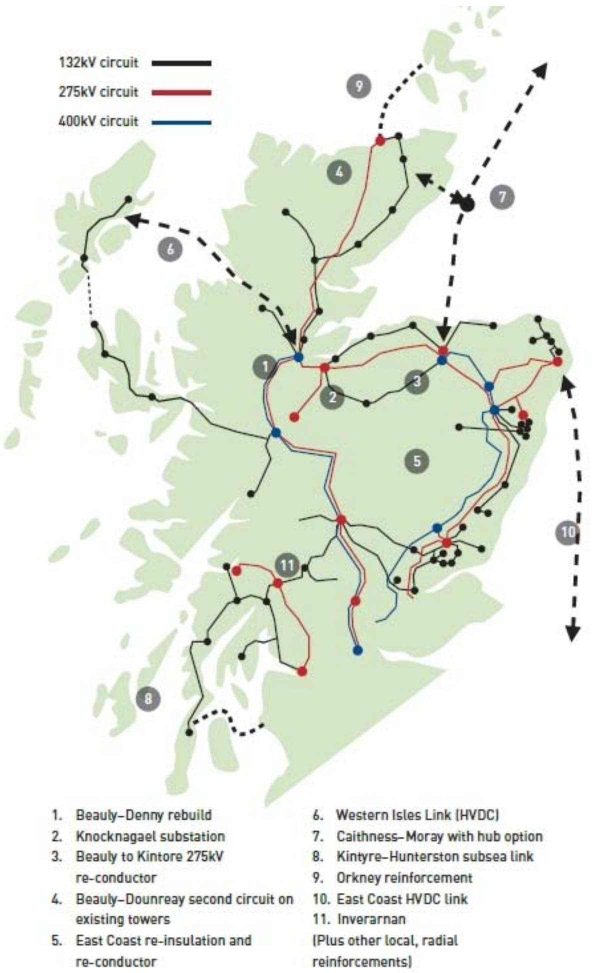
Strengthening our transmission system

these reinforcements right and then delivering them at the right time.

Figure 14 and the descriptions below provide an overview of the planned transmission system developments. For clarity, not all projects listed are shown on this figure, with the detail of the potential projects omitted for Beauly-Mossford, Shetland, Orkney Islands and Pentland Waters and Islay.

Figure 15 provides an overview of the projects which are under construction, or under development or are expected for the later years of the period and beyond.

Figure 14 Overview of planned transmission developments



Strengthening our transmission system

Figure 15 Summary of planned projects

	Completion date
Projects under construction	
Inverarnan	2010
Knocknagael substation	2011
Beauly-Denny	2014/15
Beauly-Blackhillock-Kintore	2014/15
Beauly-Dounreay	2012/13
Beauly-Mossford	2014/15
Planned system developments	
Caithness-Moray & offshore hub	2015 – 2017
Kintyre-Hunterston	2015 – 2018
East Coast 400kV Upgrade	2015 – 2018
East Coast HVDC subsea link	2018 – 2020
Western Isles link and associated onshore infrastructure on Lewis	Earliest 2015/16
Shetland link	Earliest 2015/16
Projects required for Offshore Wind and Marine Generation:	
Orkney West 132kV	2015 – 2016
Orkney West HVDC	2018 – 2021
Orkney South & East 132kV	2018 – 2020
Orkney South & East HVDC	2020 – 2022
Pentland Firth South (Dounreay – Gills Bay) 132kV	2015 – 2016
Pentland Firth South Second Circuit	2018 – 2021
Islay Link (Offshore & Marine)	2020 – 2022
Potential future main system projects:	
Beauly-Keith 400kV upgrade	Post 2020
East Coast HVDC - second subsea link	Post 2020

Caithness-Moray Strategy

The March 2009 ENSG report of the Electricity Networks Strategy Group (ENSG), 'Our electricity transmission network: a vision for 2020', recognised the need for reinforcement of the transmission network in the far north of Scotland to accommodate future onshore and offshore renewable generation in the region.

Our plans at this time are that the optimum network development to accommodate the proposed generation in this area and on the northern islands of Orkney and Shetland would comprise the following elements.

The Caithness Moray project:

- A new 600MW HVDC link between a new 132kV substation at Spittal near Mybster in Caithness and Blackhillock, Moray, to add to the export capacity of the Caithness region provided by the upgraded Beauly-Dounreay line;
- At Spittal, the new convertor station for the HVDC link, and 132kV switching equipment;
- At Blackhillock, the other new convertor station for the HVDC link, together with a 400kV switching station, connecting into the new 400kV network on the east coast;

Strengthening our transmission system

- Rebuild the existing Dounreay-Thurso-Mybster 132kV tower line at 275kV and the Spittal-Mybster 132kV line;
- A new 275kV/132kV substation near Cambusmore, at the crossing of the Beauly to Dounreay 275kV and Shin to Brora/Mybster 132kV overhead lines;
- A new 275/132kV substation near the existing Alness 132kV Tee point and interface with the existing Alness Grid Supply Point, and
- Reconductor the existing single 275kV circuit between Beauly and the proposed Cambusmore substation.

While this project comprises a number of elements, including some new onshore transmission assets, our initial view is that this is the most environmentally acceptable and cost-effective reinforcement to open up the region including the marine potential. The alternative option set out in the ENSG report was for full onshore rebuilds between Dounreay, Beauly and Keith.

The estimated cost of this scheme is around £800 million, and could be completed between 2015 and 2017.

Additional to the Caithness-Moray Project, and within the overall strategy for this region are:

- The option of an offshore HVDC hub and switching station in the Moray Firth with the uprating of the HVDC link between the hub and Blackhillock from 600MW to around 1.2GW (the hub and incremental works project), at a cost of £125M; and
- The option of terminating the proposed HVDC link from Shetland at the hub, rather than Blackhillock.

The hub and incremental works project has been developed over the past 18 months in response to a grant programme from the European Commission for innovative incremental works that might be added to existing planned works. In December 2009, SHETL was successful in gaining 50% grant funding (up to €74.1 million) for the project under the European Energy Programme for Recovery (EEPR). The hub and incremental works project is acknowledged to be a “strategic” investment that is unlikely to be economic without the grant funding.

SHETL is of the view that the offshore hub has the potential to represent an economic and efficient development of the transmission system in the north of Scotland. Our preliminary analysis suggests that this would be the most economic means to accommodate new generation connections in the far north; for example, the initial proposed marine generation in and around Orkney and the Pentland Firth or offshore wind in the Moray Firth.

Strengthening our transmission system

In addition, there is the innovation benefit of proving multi-terminal HVDC technology – essential for the realisation of large-scale offshore generation, using an integrated approach for offshore connections and leading towards a future offshore 'super grid'.

Kintyre-Hunterston

This project would allow for the connection of around 550MW of renewable generation in the Kintyre, Argyll and Bute area, which has seen significant development of onshore wind generation over recent years, and anticipates the future development of marine technologies.

This project comprises the installation of subsea cables between a new substation near Crossaig on the Mull of Kintyre and Hunterston in Ayrshire, and the rebuild of the existing 132kV overhead line between Crossaig and Carradale to a higher capacity 132kV construction.

The estimated cost of this scheme is around £200 million, and could be completed between 2015 and 2018.

East Coast 400kV Upgrade

The existing 275kV system on the east side of SHETL's licensed area runs from the boundary with Scottish Power in the Central Belt, to Dundee, at Tealing, onto Aberdeen, at Kintore, with connections at Rothienorman to Peterhead Power Station on the Buchan coast, before continuing to Blackhillock, by Keith.

Following completion of the Beauly-Denny overhead line, the uprating of this system to 400kV operation is required to further increase the capability to export renewable energy from the north of Scotland to the demand centres of central Scotland and the north of England.

SHETL works comprise a number of elements which include:

- The uprating of the existing 275kV tower line between Blackhillock (Moray) to Kincardine in the Central Belt to 400kV operation;
- The uprating of the existing 275kV tower line between Peterhead and Rothienorman to 400kV operation; and
- Substation works at Peterhead, Rothienorman, Kintore, Alyth and Blackhillock.

The estimated cost of this scheme is around £350 million, and could be completed between 2015 and 2018.

We have also identified a possible future requirement to uprate the capacity of the second 275kV tower line

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on the east, (XT1/XT2), and would achieve this by changing the conductors to an increased size and capacity. We will continue to review the requirement for this upgrade as generation volumes materialise.

East Coast HVDC subsea link

This project comprises the installation of a subsea HVDC link between Peterhead in the north of Scotland and Hawthorn Pit in north east England, over a route length of approximately 360km. The link will be rated around 2GW and will operate in parallel with the upgraded mainland transmission system to provide a significant increase in north-south transfer capacity.

SHETL is developing this project jointly with National Grid, and is sharing the design and development costs of the subsea link. Our current and early estimate of SHETL's 50% share of this scheme is around £700 million, and is programmed for completion in 2018.

Western Isles link and associated onshore infrastructure on Lewis

The Western Isles project includes a 450MW HVDC link between Grabhir on the Isle of Lewis, and Beauly on the Scottish mainland. A cable will be laid from Lewis to Dundonnell on Little Loch Broom, and then continue cross-country as underground HVDC cables to Beauly. The project includes AC/DC converter stations at each end.

The 450MW rating of the link is driven by the volume of contracted generation seeking connection on Lewis, which comprises two potentially large-scale developments and a number of smaller scale and community-based schemes connecting into the island's distribution network.

Preconstruction work is substantially complete, with the project ready to move to the construction stage. The timing of construction start and the resulting completion date will depend upon the larger developers confirming their readiness to proceed.

Additional 132kV transmission infrastructure on Lewis will connect the AC/DC Convertor station at Grabhir with the existing transmission system at Stornoway. This allows the smaller generation schemes to connect and allow the new link to have a role in securing demand on Lewis, and so reducing reliance on the existing diesel generation station.

The estimated cost of this scheme, including the 132kV infrastructure, is estimated at £430m and the earliest completion would be autumn 2015.

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Shetland link

The Shetland project comprises a new 600MW HVDC link between Upper Kergord on the Shetland mainland and Blackhillock on the Scottish mainland. The link comprises a single circuit of 320km subsea and 25km onshore underground cable, and includes AC/DC converter stations at each end.

The project is driven by the contracted generation seeking connection on Shetland, principally one potentially large-scale development, but allowing for some smaller-scale generation to be accommodated. The timing of construction start and the resulting completion date will depend upon the large developer confirming readiness to proceed.

The estimated cost of this scheme is around £450 million, and the earliest completion would be 2015. As described above, in the event that the proposed offshore hub is established in the Moray Firth, the link would be established from Shetland to this hub point, significantly reducing the radial length.

Orkney & Pentland Firth

Orkney Isles and the Pentland Firth are rich in renewable resource. Onshore wind has been developed on the islands for many years with one of the first development turbines established at Burgar Hill in the 1980s. Subsequent development has occurred for relatively small-scale generation, but with the potential for both larger and community scale schemes. For marine generation, Orkney has the EMEC development and test facilities for both tidal and wave technologies, and the aspirations to develop up to 1.6GW of marine generation via the Crown Estate leased waters.

In developing our investment plan, our central assumption is that around 30% of the potential 1.6GW capacity of marine generation already under consideration and development will be constructed within the period to 2020, representing around 500-600MW.

Based on connection applications received in late 2010 and early 2011, we have referenced in connection offers a requirement for an initial 132kV subsea link of around 180MW capacity between the Orkney Islands and Dounreay in 2015/16 to service the first tranches of marine sites off the west and north of the Orkney mainland, together with developing onshore renewables.

Should marine generation deploy in line with the connection applications and agreements, there would be a requirement for this to be followed by a link between the west of Orkney and the Scottish

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mainland of greater capacity, probably using HVDC technology, towards the end of the eight year period, around 2018-2021.

For the south side of the Pentland Firth, a twin 132kV link within Caithness will provide capacity for the first phases of marine generation, connecting into the Caithness 132kV and 275kV system between 2015 and 2016. This may also need to be followed by a link of greater capacity, either at 132kV or at HVDC later in the eight year period. This would depend upon the rate of growth of deployed marine services in these waters.

Further development of marine renewable is anticipated on the north side of the Pentland Firth, in the Flotta & South Ronaldsay areas, which may also be supplemented by small volumes of onshore generation, perhaps up to 100MW, across these southern isles of the Orkney Group. In order to accommodate this generation, there would be a requirement for an initial 132kV 180MW subsea link between this south Orkney area and the Scottish mainland, perhaps at the new Spittal substation, around 2018 or 2020. Dependent upon the rate of growth of the marine generation in these waters, there might then be a need for this to be followed by a HVDC link of greater capacity between 2020 and 2022, for which investment expenditure would commence in the later stages of the RIIO-T1 period.

The requirement to establish subsea links beyond the initial 132kV cables, and their timings, would depend upon:

§ All of the prospective marine generation materialises within the period;
§ The location of the generation clusters develop in a particularly dispersed manner, and
§ Other generation develops independent of these Crown Estate agreements.

The costs for the 132kV subsea links from Orkney are each estimated at around £125M.

There is a probability of more than one HVDC link being required for the three locations of West Orkney, South Ronaldsay and Caithness's Pentland Firth coastline. It is likely that these HVDC links will be connected to a new HVDC hub point on the Caithness shoreline, and then linked to a main HVDC hub at Peterhead, where export routes would exist on the onshore 400kV system and the offshore East Coast HVDC links.

The costs of the HVDC links are each estimated at £250M to a Caithness shoreline substation, and with a £500M link to the main system at Peterhead.

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132kV Local Infrastructure Projects

The 132kV networks in the north of Scotland perform one of two functions, as part of the overall integrated transmission system. Several are radial extensions to the main transmission system and their original purpose was to provide supply to communities in the western and northern areas beyond the main system.

Onto these radial single or double circuit 132kV overhead lines, hydro and small local generation schemes are also connected. Other 132kV circuits form part of the main interconnected system and operate in parallel with the 275kV circuits; the circuits running to the south and east of Beauly are the main examples of this function.

These circuits, categorised as shared-use infrastructure, generally have a capacity of around 100MW per circuit, and some upgrading, rebuilding or extension of these existing 132kV networks may be required where one or more large windfarm schemes are proposed to be connected on the circuit, perhaps together with an increase in the volume of relatively small renewable generators on the distribution network. Circuits whose original purpose was to provide local community demand, such as in Kintyre, Argyll & Bute are now forecast to experience a reversal of the net power flow with renewable energy now being exported out of the region.

For these circuits, the requirement for reinforcement is dependent upon the establishment of one or more specific generation schemes, and so there remains some uncertainty regarding the need, timing and scope of each prospective upgrade.

A summary of the 132kV circuits for which reinforcement is forecast is shown below.

	Prospective completion dates
132kV Local Infrastructure Projects under development and potential future	
North Argyll – Dalmally Substation	2015 – 2017
Taynuilt – Inverary	2016 – 2018
Inverary – Crossaig	2017 – 2019
Fort Augustus – Fort William	2017 – 2020
Beauly – Tomatin	2017 – 2018
Keith – Tomatin	2018 – 2020
Other related infrastructure projects	
Knocknagael – Foyers 275kV upgrade	2014 – 2016
Pentland Firth South (Dounreay – Gills Bay) (New circuit - as above table)	2015 – 2016

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In order to address this uncertainty we have proposed that a shared-use revenue driver mechanism is utilised which would provide funding for a percentage of the potential investment, with any additional investment being a function of the generation capacity connected or the firm network capacity provided on the upgraded circuits (see previous section).

Potential Future Projects

In total, the schemes above represent the majority of our likely capital expenditure investment requirements over the next decade to 2020, and our main focus is getting these reinforcements right and then delivering them at the appropriate time and at the lowest cost.

The projects identified and described above are sufficient for the majority of the contracted generation, which includes onshore wind generation in the Western Isles and Shetland, offshore generation in the Moray Firth and marine generation in the Pentland Firth and Orkney Waters.

Should some of this contracted generation be delayed in its proposed development, or indeed, fail to be developed, some specific projects may be delayed until such time as the requirement for transmission capacity is re-established. On the other hand, further investment and upgrading of the transmission system would be required within the price control period should all of the contracted generation, together with future additional generation, be successfully developed.

Particular areas and technologies which will significantly influence further development include the development of marine generation, not only that currently the subject of Crown Estate leases in the Pentland Firth and Orkney waters, but also on the western seaboard of the Inner and Outer Hebrides, where the planned deployment of smaller scale schemes may increase and precede the establishment of larger schemes.

The Crown Estate development zones for Islay and the Argyll Array are already being assessed by developers, and would require subsea links to points of strong transmission infrastructure on the Scottish mainland. Similarly, further additional offshore wind around the coast of the north of Scotland, perhaps together with increased marine volumes, would require future large HVDC links from these locations to HVDC hub points on the Scottish mainland, with even higher capacity HVDC links taken from these hubs to the north of England.

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Particular projects worthy of note which are most likely to be required or established post 2020 are identified below.

Second East Coast HVDC Link (Peterhead to England)

The proposed east offshore HVDC link is required to accommodate the first developments of the offshore wind in the Moray Firth, together with the first phase of marine generation outputs from the Pentland firth and the Orkney Waters. A second HVDC circuit could be required from an established Peterhead hub to the north of England in order to increase the capacity of the Scottish transmission system to export power in bulk to the more southerly demand centres.

The Islay HVDC Link

For the Islay offshore windfarm in the Crown Estate development zones and marine energy developments off Islay may require an onshore connection point on Islay to collect generation from multiple sites around 2020-2022. From that collection point a subsea link would be required to a point of strong transmission infrastructure on the Scottish mainland, either in SHETL licensed area or in Scottish Power Transmission network in the south of Scotland.

Beauly-Blackhillock 400kV

There may be a need, in accordance with the requirements of the NETS SQSS security standards, to rebuild one of the existing transmission routes between Beauly and Blackhillock, along the Moray coast, for generation north in the north of Scotland (north of the B1 boundary) and from the island groups of the Western Isles, Orkney and Shetland. This generation would benefit from both the increased transmission capacity and the additional system security that the completion of a 400kV ring system reinforcement would provide, in the event that volumes of renewables generation are of such a scale to warrant the relief of otherwise constrained energy.

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Our SHETL 'Best Estimate': Factors that will influence our investment decision

When we have identified particular projects that might meet users' requirements in a particular geographic area, we need to decide when to invest. The timescales indicated above are the dates by which we expect to be able to complete the individual projects. The question of when we start work and then now long that work takes is subject to a number of unknowns, or uncertainties, which are described below.

Project uncertainties

At a project level, the uncertainties include:

The needs case

This is a detailed piece of analysis that confirms that the technical and economic case for the project is made and is robust.

Since these transmission projects are driven by the requirement to connect and provide transfer capacity for the growth in renewable generation, the needs case is heavily reliant upon the certainty of renewable generation being developed and connecting to the system.

For an island group or an area in the west Highlands served by a radial transmission network, this can depend upon an individual, or a small group of, relatively large generation schemes, with the case supported by smaller schemes connecting onto the local distribution network. For the main interconnected system on the mainland, the case will depend upon the impact of the volumes of generation aggregating to form substantial flows of power from the north of Scotland to the south.

Some generation schemes will be already connected, whilst others will be under construction, or consented, or in the various stages of their planning process. Consequently it is necessary to confirm that there is sufficient certainty around a portfolio of generation to provide the requirement for a specific transmission project. An understanding of the phasing of the development of the generation schemes will also inform the timing of the transmission project.

One tool we have to inform the need case is the requirement for developers to provide a form of underwriting for the design and construction of the projects. This provides a strong signal and certainty that the project is ready to proceed, and will avoid unnecessary investment in the system.

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In addition to committed generation schemes, other pertinent information in support of the needs case is provided by the general activity of generation in an area, which may not be at the stage of commitment and underwriting. Specific generation developments may not have a connection agreement, but may be in scoping or making planning application to the local council or to Scottish Government.

Less certain, but still relevant, is the general resource potential of an area which may be reflected in the council's Local Development Plan, both identifying and supporting the development of renewable generation in its area.

Project scope

This is about making sure the reinforcement is not too big or too small and that it is at the right technical standard.

The scope of the project is determined from the requirement to provide adequate transmission capacity for the connection and power transfer of the developing generation in accordance with the national planning standards. It will be refined as generation volumes and locations are confirmed in order to provide the optimum design, but could be impacted by a significant change to the assumed generation.

Project duration

Getting the timing right for both commencing the build and connecting the generation ensures that we keep costs down for our customers.

The projected completion date for a project is determined by the requirements to provide physical connection to generation schemes, and adequate transmission capacity for the region, and determined by the timescales of the project itself to complete the various phases of engineering and design, planning and consenting, supplier procurement, manufacture, build and commissioning.

Timing of the completion date would be extended if any of these overrun, for example if:

- Planning applications become subject to appeals or unexpected conditions;
- System outage dates, required for integrating the project into the existing network, are restricted due to other work on the overall system; or
- Manufacturing or contractor capacity is limited for a particular technology or equipment type.

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Portfolio uncertainties

As noted above, the overall development of the various projects is subject to interactions between themselves and development across the wider and global marketplace.

System outage requirements

This is an issue of great concern within the north of Scotland, as a restriction on the number of concurrent outages is necessary to ensure the reliability and continuity of the transmission system to meet local demand and generation needs.

A number of competing pressures will be placed on the system over the next decade to allow for the integration of these specific projects into the existing network, to connect individual renewable schemes into the network, and to ensure the ongoing maintenance of the existing assets is not compromised.

Outage programming is a co-ordinated activity between ourselves and National Grid as system operator, with the system operator having responsibility for the operational integrity of the overall system, and co-ordination of the annual outage programmes.

We will continue to work closely with National Grid to ensure the programme is optimised and that the impact of any restrictions on the construction of the projects is mitigated. This issue is discussed in **Our Network Availability Policy** later in this document.

Supplier capacity

This is an issue about sourcing all the equipment we need which is increasingly on an international scale, particularly for the provision of transmission equipment.

We already procure transformers and switchgear, cables and overhead line conductor from suppliers across the world. The recent development in the growth of offshore renewable generation, often distant from onshore networks, and the increase in interconnections between countries and markets are resulting in an increase in the use of HVDC technology.

Recognising these uncertainties and the approach to the regulatory funding of the projects is critical to us and is discussed in the next section.

Reflecting the probability of all projects not proceeding within the period

We have described above the factors which lead to uncertainty over the need for individual investment projects, assessed on both a technical and economic fronts.

The uncertainty not only relates to the need for the project, but also for the scope and timing, and one of the key factors in the uncertainty in the need case is based on the portfolio of renewable generation driving the reinforcement. Within that portfolio, account needs to be taken of the various stages of readiness that groups of generation developments have reached at the time of assessment.

In order to forecast the likely range and spread of investment over the RIO-T1 period, we have taken the view that the most effective way of indicating the likelihood of the projects being required and commissioned in the period is to apply a ‘diversification factor’ to the sum of the construction costs of the possible projects.

This reflects our experience in progressing a programme of large capital projects, where projects tend to be established later, rather than earlier, than originally foreseen, and due to a number of differing factors.

There is potential difficulty in justifying the requirement of some specific schemes, where a regional portfolio of generation may only proceed to develop at a much slower rate than expected, and relative to development generally across the north of Scotland. This may be due to regional difficulties in developers gaining planning consents for their projects, perhaps due to local opposition against the cumulative effect of onshore generation, or may reflect a general difficulty in developing and deploying a specific technology type, such as tidal or wave generation.

Similarly, a particular transmission project may be directly dependent upon a single or a few large generation projects, and the delay or failure of these projects to develop would delay or shelve the directly associated specific project. Such a scenario might be the case for some of the island HVDC links and the large offshore windfarms, and the shared-use infrastructure of 132kV radial networks.

We have also taken into account the potential risks to the individual transmission project, described above, which include the changes to the scope of the project, impacted by a significant change to the assumed generation and the extension to the completion date, due to effects of:

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- planning applications becoming subject to appeals or unexpected conditions;
- system outage dates, required for integrating the project into the existing network, being restricted due to other work on the overall system; or
- manufacturing or contractor capacity is limited for a particular technology or equipment type.

In the central case in our Business Plan, we have diversified the overall construction costs of possible wider system reinforcements by 60% in order forecast a likely phasing of investment over the RIO-T1 period.

The selection of this diversification factor is based on our experience to date and our judgement of the possible outturn of investment by the end of the period. In particular it is informed by the possibility of one or more projects failing to proceed to construction within the period, and by the risks of delays to projects from the above factors. The potential sum of the wider works costs of some £4.6 billion over the eight year period, has been reduced to £2.8 billion in the central case.

Whilst the selection of 60% provides an indication the likely investment requirements over the period, the sensitivity of it can also be tested by the use of other such percentages. In addition, the investment requirements are also bounded by the outlying scenarios of lower and upper investment cases.

Nevertheless, it is important to recognise that individual projects will be developed through the pre-construction phases, and will be brought individually to Ofgem for funding assessment and approval (as described below). In this way, no judgements are being made which would affect the timing of the project moving to construction, beyond the basic assessments of need and timing informed by the indicated requirement of developers regarding the timing of their projects, and their requirement for local connection and the provision of associated capacity in the system's wider works.

For the upper case, a number of projects are advanced within the period. The case is based upon the Accelerated Growth scenario and assumes the successful deployment of marine generation and offshore wind within the period, so that the high capacity transmission projects related to these developments are advanced and commissioned towards the end of the period. Should all of the investments be required and deliverable, the investment profile over the period would total some £5.6 billion. With some reduction included to reflect potential delays or deferment across projects, again at 60%, this scenario indicates some £3.4 billion for these wider works.

The much more pessimistic lower case is based upon the Slow Progression scenario and takes the view that there will be consenting effects on onshore wind that will delay some of the projects whilst others will either reduce in output or fail to proceed. With the deferral of investments related to marine and offshore wind, the investment profile over the period would total some £2 billion. With further reduction included to reflect potential delays or deferment across transmission projects, this time at 50%, to reflect a more pessimistic environment for renewables, this scenario indicates only £1 billion for these wider works.

Getting the Timing Right

Design and pre-construction work

As stated above, we have made the assumption that the application of a ‘diversification factor’ to the sum of the construction costs is the most effective way of indicating the likelihood of the projects being commissioned in the period. This is only an assumption, and justified, individual projects will be progressed and delivered in as timely a manner as possible.

In order to ensure we are ready to progress the construction phase of each project, it is important that we are ready, and have given a focus to the pre-construction work.

The development of projects progresses in two phases, firstly the preconstruction works of design, environmental assessments and consents; secondly the physical construction phase. This split provides further protection against the risk of investing too early or too late, by progressing the pre-construction phase at relatively low cost, to a position where a decision can be taken to proceed to the significantly more expensive construction phase once the needs case and detailed cost are confirmed and have been fully assessed.

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We believe this arrangement provides a relatively simple, transparent and pragmatic solution to manage the considerable risks and uncertainties presented by these schemes to existing and future customers, as well as to our business. In particular, by only applying to Ofgem for construction funding as and when a project can be shown to be needed, customers will not be asked to pay for that project too soon.

For the second phase of construction, we are proposing to adopt a case-by-case approach to timely investment in wider system reinforcements. We will apply to Ofgem for specific project construction funding once there is a credible needs case to justify the project. If Ofgem supports our case, we will then make a detailed cost submission that will enable Ofgem to make a confident funding decision.

From our stakeholder engagement, there was support for the principle of progressing pre-construction (design and consenting) work and funding for potential transmission infrastructure developments, in order to optimise construction readiness with confirmed need, and avoid undue delay. For this first phase of design and pre-construction, it is important that this work is progressed in a timely manner, such that the decision to move to construction is ready at the appropriate and earliest opportunity.

The design and pre-construction preparation apply to projects for which investment can be anticipated based upon the indications from renewable developers on their indicated timescales for their projects, together with targets and aspirations for the development of renewable resource in regions across the north of Scotland, such as the prospective development of up to the 1.6GW of marine resource in the Pentland Firth and the Orkney Waters. In this regard, whilst many of the transmission projects can be expected to complete by 2020, other projects will be completed post 2020.

The total portfolio of possible transmission projects required as a result of the prospective generation for the wider works and the shared infrastructure projects is some £6 billion.

Pre-construction works for this portfolio of projects is forecast to be some £100-120 million, with some of these costs being incurred during 2010/11 to 2012/13, prior to the RIIO-T1 period. This represents some 2% of the total costs, and is proportionate to the overall costs.

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Over the RIIO-T1 period itself these costs are forecast at around £94 million. Of this total £60 million is required in the first four years of the period addressing the initial workload of preparing a number of projects for construction. The balance of £30 million in the latter four years prepares for projects expected to commence construction at the end of the period, or into the 2020-2025 period.

Some costs have been included on a non-project specific basis to allow for the emergence of new projects, or additional scopes of work, in the period which cannot be foreseen at this stage. These non-specific costs amount to some £15.5-16 million of the £94 million, of which some £6 million occur in the first half of the period, and some £9 million in the second half to allow for greater uncertainty in that later phase.

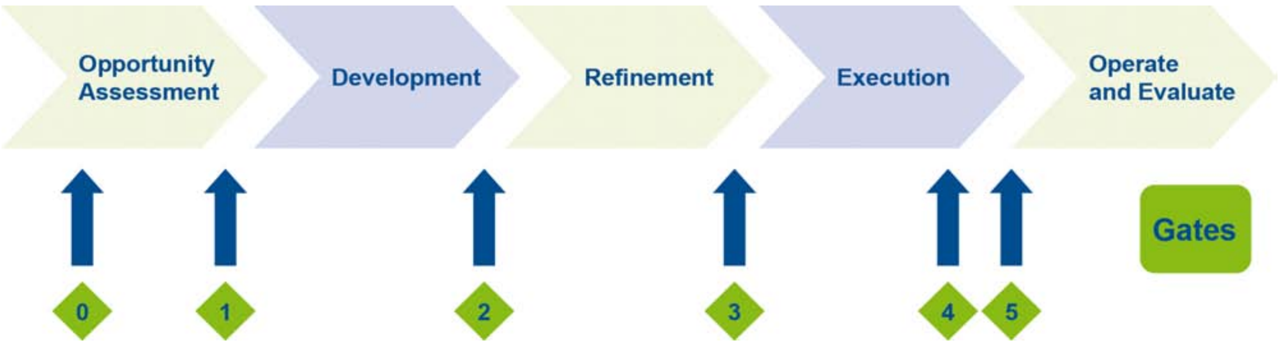
Delivery

To ensure that all transmission projects are governed, developed, approved and executed in a consistent and effective manner, each project will be required to work within the guidelines of the SSE Large Capital Framework (LCP).

The LCP consists of 5 main stages or gates (Figure 16):

§ Gate 1: Opportunity Assessment
§ Gate 2: Development
§ Gate 3: Refinement
§ Gate 4: Execution
§ Gate 5: Operate and Evaluate.

Figure 16 Gate Positioning in Governance Process



The design and pre-construction costs will cover development of the projects through the first three LCP gates and covers the following activities:

Opportunity Assessment

The opportunity assessment phase involves high level appraisal of the project needs case in determining potential technical solutions with a view to developing a project brief for further development. Typical activities within this phase include:

- High level economic assessment appraisal of options.
- Development of Single Line Diagram of proposed requirement.
- Network design studies.
- Identification of key interface points with other projects.
- Preliminary engineering based design evaluations.
- High level environmental appraisal for potential siting options (developed in conjunction engineering design option).

The key deliverable from this phase of the project is to verify the needs case for the project and provide a project scope for further development within the project team.

Development

The development phase builds upon the works carried out within the opportunity assessment phase with the key objective being to identify a preferred technical solution and to obtain any necessary consent for the project.

Typically at this stage of the project the project team will have a number of specified technical parameters (e.g identified system connection points) and geographical search areas to work within. The identification of the preferred technical solution requires input from both an environmental and technical perspective.

Environmental specialists will be engaged to assess the identified search areas with a view to determining a number of potential sites (e.g for a substation location) or route corridors (e.g for an overhead line route). Desktop surveys and available information will be utilised to inform this process which will then scope the requirement for further works and investigations.

Preliminary engineering studies are required at this stage to determine basic engineering parameters for the assessment of the various sites and route corridors. This may include initial geotechnical investigations, tower and line surveys, and topographic surveying.

Interaction and engagement with stakeholders is crucial to the successful development of projects. At this stage a contact would be made with key stakeholder: representatives of the local community; statutory consultees; MPs MSPs; and may involve formal public consultation.

Once the preferred technical solution has been identified there is a further requirement to carry out detailed environmental survey works (EIA surveys) and engineering design works in preparation for consent applications. For projects involving subsea cabling this will include significant costs for marine survey works. There is also the possibility of costs incurred due to consent applications being rejected and associated public inquiry costs.

Refinement

The refinement phase involves detailed engineering site investigation, engineering design and tendering works to finalise the project design and improve project costing accuracy in advance of the construction phase of the project.

Typical engineering site investigation works could include detailed soil investigations for substation platforms or overhead tower foundations. Further detailed engineering design works are usually required in advance of the tender preparation and contract negotiations. As well as the engineering aspects there is also a requirement to develop any environmental mitigations associated with the project consent conditions.

The logic applied at this stage is that effort applied at this upfront design stage provides more cost certainty and lowers the risk of change during the construction phase of the project. The key output measure from the refinement stage of the project is to ensure that the project has been fully designed and costed in advance of construction funding.

The pre-construction activity does not generally include:

- significant challenges for planning application or public inquiries assumed for all projects
- conditions related to the granting of planning consent
- type testing of equipment
- civil works preparation or mobilisation costs

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In conclusion, at the end of the design and pre-construction phase each project will have:

- All necessary consents in place.
- Undergone a robust design process with any outstanding design risks documented and understood.
- Project budget defined with high degree of cost certainty based on tendered prices for key contracts and detailed account of project risk.
- Demonstrated project management compliance with the SSE LCP framework.

About the funding of large transmission projects

This section sets out our approach to dealing with wider works uncertainty.

In summary, we are proposing to adopt a 'within period determination' mechanism. Under this mechanism, we do not receive an allowance for large capital project upfront as part of the price control settlement. Rather, once the needs case for a project can be demonstrated and we have undertaken pre-construction, we will then apply for our licence to be modified to allow construction funding.

This preoject-specific funding mechanism would apply to all network investment projects in excess of £50 million (in 2009/10 prices).

Context

Our Business Plan includes a *ex ante* base capital expenditure allowance of around £1 billion. However, our Business Plan also recognises that investment could reach as much as £6 billion during the RIIO-T1 period (or as little as £2.5 billion). The uncertainty over our expenditure is a function of the connecting generation, linked in part to the timing of these schemes and in part to whether or not they come to fruition.

Whilst we have developed two revenue drivers: one to address volume uncertainty associated with local sole-use infrastructure; a second to address volume uncertainty associated with local shared-use infrastructure (see previous section titled 'About the funding of new connections'), we need a further funding mechanism for wider work / large capital projects, which are unapproved at this stage but may come forward within RIIO-T1 timescales. For this purpose we have developed the within period determination mechanism for wider works described in this section.

The within period determination mechanism builds on the Transmission Investment Incentives (TII) mechanism established during TPCR4, following the Government's Transmission Access Review.

About the funding of large transmission projects

By ensuring that SHETL had the flexibility to come forward for funding at any point in the price control period when the needs case for a large capital project was made, the TII mechanism worked well in TPCR4. The within period determination seeks to further improve the TII mechanism and we believe offers the most appropriate approach to funding large capital projects during the RIIO-T1 period given the scale of the projects, the scale of our business and the scale of the uncertainty.

In addition to the within period determination mechanism, two other mechanisms have been proposed for dealing with this uncertainty: (i) a trigger mechanism and (ii) an upfront volume driver. However we do not believe these are appropriate mechanisms for SHETL.

Whilst we welcome the automatic nature of these alternative mechanisms, both of these mechanisms require TOs to put forward some element of cost forecasts at the price control review stage, which they are then held to. Given the scale of the projects in SHETL's area, this would result in an inappropriate level of risk resting with SHETL, and, potentially, inefficient spend for customers should, over the course of the price control, projects that were committed to at the review stage change in terms of their necessity.

To put this in context, we have around £6 billion of uncommitted, but named, large capital projects that have the potential to come forward during RIIO-T1. Given the uncertainty we do not believe that customer should be committed to a cost and delivery timetable for these projects now. Instead, we believe a more appropriate and prudent approach is to present our case for funding on a case-by-case basis as and when there is a genuine need.

We believe that our approach ensures that only those projects that remain justified at a point in time close to investment are given the green light in terms of funding. This approach has been supported by our stakeholders.

The following turns to our more detailed points: in particular our views on how best to apply this mechanism in practice to ensure that some of the more bureaucratic aspects of the TPCR4 approach are addressed.

About the funding of large transmission projects

Treatment of pre-construction costs

We do not believe that pre-construction costs (including planning, design and the preparation of planning applications) should be part of the within period determination mechanism. Rather, as at TPCR4, we propose such costs form part of our *ex ante* base capital expenditure allowance. This will avoid introducing unnecessary delays to these schemes during the early stages.

Project eligibility

Currently we believe that there is a lack of clarity around when the TII mechanism is actually applied. In this respect, we believe the best approach is one that is clearly defined. This is true of all uncertainty mechanisms.

To this end, we support a within period determination materiality threshold. For SHETL, we believe that the threshold is £50 million. Projects with a forecast construction cost that exceeds this threshold are eligible to progress to the submission of their needs case; all other capital expenditure would fall within either the *ex ante* base capital expenditure allowance or revenue driver mechanisms (including high cost project element that sits within this).

Two-stage process

We support a two-staged approach to the within period determination mechanism: the submission by the TO of its needs case, followed, if successful, by a robust cost assessment. To be clear, the project could only progress to the second stage once the needs case had been demonstrated and supported by Ofgem and wider stakeholders.

We believe this two stage approach, together with the materiality threshold, provides clarity over the due process and will help to filter projects to ensure that only projects worthy of the within period determination process are progressed through to the more detailed assessment. This will significantly improve the efficiency of the TII mechanism.

It is a key question at what point do we decide to make an investment? In our consultations with stakeholders over the past year, we set out our initial view that this should be as and when we can demonstrate that the investment is required and can be delivered. Our preference was to continue with the existing regulatory approach, i.e. we make the case to Ofgem at the appropriate time. We specifically sought stakeholder views on this issue and, in a recent publication, Ofgem noted that:

About the funding of large transmission projects

"There was clear agreement across stakeholders of the need to include a variety of flexibility mechanisms to help manage the uncertainty around costs, timing and scale of critical infrastructure investments. Stakeholders particularly welcomed the continuation of a mechanism for within-period cost determination closer to the point when TOs undertake construction, particularly for those reinforcements that are large scale."

In line with Ofgem and stakeholders, we agree that it would not be efficient to prescribe time windows for the submission of the needs case. Maximum efficiency will be reached if SHETL is able to bring forward its needs case as and when it is ready. There is always a risk in shoe-horning submissions to meet defined dates: this will almost always encourage submission before the case is fully ready; or delay projects while they wait to meet a rigid timetable.

Figure 16 shows an illustrative timeline, which we have followed to progress our TII projects within TPCR4. We believe this is consistent with the type of timeline that Ofgem and stakeholders could expect in respect of within period determination projects.

Form of the within period determination mechanism

We want to put in place a clear and transparent mechanism for uncertain costs relating to wider works. To this end, we favour a mechanistic solution, i.e. one that involves little if any adjustment to the licence following the Authority's approval of our needs case.

We believe that there are three parts to the licence condition that will facilitate the within period determination mechanism:

§ Initial assessment phase,
§ Delivery phase, and
§ Post-construction assessment phase.

Initial assessment phase

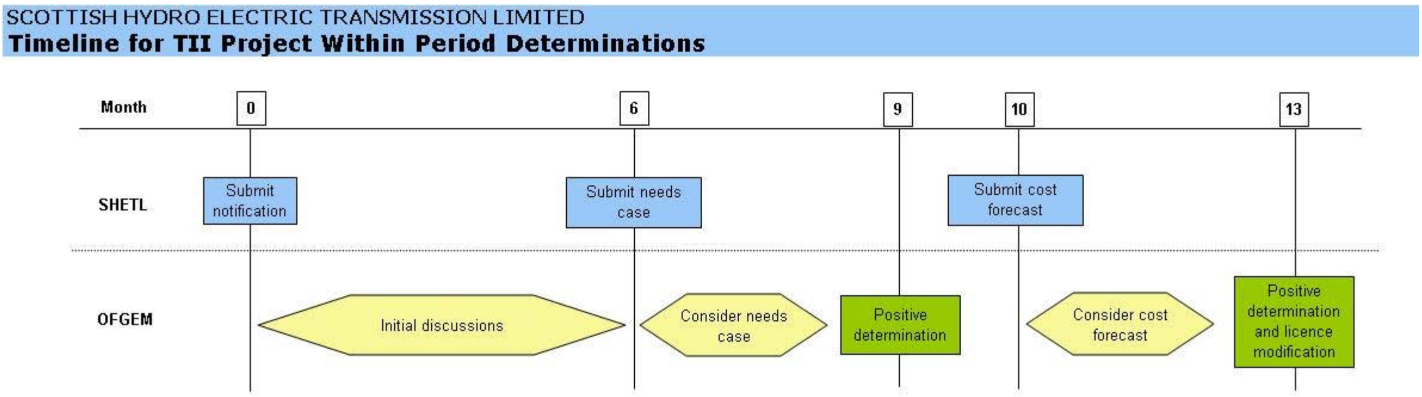
The initial assessment phase will follow the two stage approach set out above.

The key issues with the initial assessment phase are setting out the eligibility criteria, the information that is required for the assessment to be made and the timeline.

We believe that these issues are best addressed through a guidance document rather than in the licence. This document should include:

About the funding of large transmission projects

Figure 16 Timeline for within period determination mechanism



- An eligibility threshold which, for SHETL, is all large capital projects that commence construction after 1 April 2013 and are of forecast construction cost in excess of £50 million (in 2009/10 prices).
- No time windows for initial submission, but the requirement to provide six months notification of intention to submit a project.
- Information that must be included in the needs case submission including evidence of consultation with affected stakeholders.
- Timeline for Ofgem's assessment of the needs case, and the criteria that will be used in coming to its view. We believe that this would take around three months.
- Information that must be included in the cost submission.
- Timeline for Ofgem's assessment of the cost submission, and the criteria that will be used in coming to its view. We believe that this would take around three months.

About the funding of large transmission projects

The outcome of the initial assessment phase is a determination from Ofgem. This might be that the needs case has not yet been demonstrated (with recommendation), or that the cost forecast is not sufficiently robust.

Alternatively, Ofgem might determine in favour of the investment. In this case, Ofgem would determine on the scope of the investment project (outputs) and the efficient forecast costs. Ofgem's decision on costs might be an *ex-ante* allowance or might include an element of pass through of costs. Pass-through might be appropriate where the costs are outwith the control of the licensee, for example, currency fluctuations.

Delivery phase

If Ofgem determines that funding should be allowed for a large capital project, then this would result in a licence modification.

This modification would have two parts:

§ A revenue allowance, and

§ A description of the project milestones and outputs.

As with the TII mechanism, the revenue allowance would provide a return and depreciation on the agreed capital expenditure forecast. A 'shadow RAV' approach would be used with forecast expenditure added to the shadow RAV in the year it is incurred for the purposes of determining revenue. The financial assumptions we have described in our supporting document **Determining our Allowed Revenue** would be applied to determine the revenue. RPI would be applied as per normal regulatory arrangements.

An efficiency incentive mechanism would apply to the difference between actual and forecast expenditure on the project. We support the continuation of the current incentive mechanism that results in a one-off cash adjustment in the year following construction with a 25% sharing factor applied. However we note that this should be reviewed on a project-specific basis to determine an appropriate level of risk for the agreed financial assumptions. In some instances, it might be appropriate to cap and collar the incentive mechanism.

We do not believe that it would be appropriate to re-visit the construction cost allowance in the delivery phase. However, there is always the potential for exceptional events so provision to reopen in these circumstances should be available.

Again, as with the TII mechanism, project outputs should be defined in the licence. We do not believe it is necessary to include annual milestones in the licence, as the actual phasing of a project is hard to fix. That said, we do believe that there should be requirement for licensees to report progress (including expenditure) on an annual basis to Ofgem and stakeholders. This annual report would not be subject to external audit.

Post-construction assessment phase

On completion of the project, the licensee would be required to submit a final expenditure and technical report to Ofgem. This should be supported by an external auditors report.

At this point, in the first year after construction, three things would happen:

- The capital expenditure incentive mechanism would be automatically applied.
- An operating cost escalator would applied to increase allowed operating costs by 1% of the Gross Asset Value (GAV) of the new asset.
- Ofgem would determine on efficient outturn costs and the shadow RAV would be adjusted accordingly.

Thus the revenue allowance in the post-construction period would comprise a return and depreciation on the efficient capital cost, plus an operating cost allowance.

We believe that the shadow RAV should remain in the licence until the next price control, at which point it would be incorporated into the main RAV.

Delivering our capital programme

This section sets out our approach to addressing the challenge of resourcing and delivering the programme of large capital projects over the RIIO-T1 period. It covers the role of the Large Capital Project (LCP) governance framework, internal resourcing and strategic partnerships.

On resourcing and deliverability, some stakeholders commented on the importance of ensuring we can resource the delivery of these projects. We agree that this is crucial. In a recent report on our plans, KEMA, a leading authority in energy consulting, made the following observation:

"SHETL is evolving its supply chain and delivery strategy on three fronts to meet the rapid increase in expenditure through strategic developments associated with: internal resources, the external supply chain and contracting resources."

As a consequence, we devoted substantial effort in recent years to preparing for delivering our transmission work programme.

Our delivery framework

The SHETL investment portfolio is governed under the SSE Group's Large Capital Project (LCP) Governance Framework.

The LCP framework has been developed to ensure that all large investment projects are governed, developed, approved and executed in a consistent and effective manner, with consideration of best practice in project delivery.

SHETL's goal is safe, sustainable and timely execution of the portfolio, delivering projects in line with our Business Plan. Thus Project Directors and Project Managers must ensure that the level of project governance applied to all projects is comparable or better than the SSE Group Governance Framework.

The project delivery structure encompasses best in class project management techniques, using a Gated process and incorporating Project Review Boards, Compliance Reviews, Project Risk Reviews, Project Safety Reviews and Commercial, Insurance and Legal reviews. The Framework details what is required to manage projects across their entire life cycle from development to operations. While the Framework is not a detailed technical manual on specifics of project execution, the SHETL business unit produces the necessary standards, procedures and work instructions to enable the secure execution of transmission infrastructure projects. The Framework also describes the key roles required to populate project management teams.

SHETL Resourcing

The shortage of appropriate technical skills is well known within the industry. Two years ago, SHETL embarked on a strategy to recruit, develop and retain key project management resources to support the capital programme.

Many of the key skills required to deliver the programme are sector independent, including project managers, project controls, quality, risk management, health and safety management and site control. Since our strategy was developed, skills have been acquired from sectors such as petrochemicals, water, rail, oil and gas, pharmaceuticals, power generation as well as electrical. The focus has been on attracting experienced hires from these sectors and integrating them with experienced electrical engineering resource from SHETL's core business. SHETL has been able to attract quality resource and turnover has been minimal.

Project Delivery

In parallel with the recruiting process, it was also recognised that SHETL alone could never provide sufficient resource, of sufficient expertise to execute the entire programme. That was never our intention. SHETL is the client and as such, has developed a contractual framework where SHETL is positioned as the 'intelligent client'.

An extensive exercise was undertaken to secure a project delivery partner, where project delivery was the core business of that partner. A one year tender process was undertaken and KBR was selected as the preferred partner. KBR are an experienced project management contractor with expertise worldwide on a range on large projects, utilising a range of contracting strategies. KBRs core values are closely aligned to SSE and the availability of resource in the UK, and particularly Scotland, was excellent. The contract was implemented in October 2010.

The role of the delivery partner is to provide expert resource to supplement the SHETL core team. The specific role that KBR occupy on any project is determined by the risk profile of that project. The role may be on a supplemented resource, or PMC basis.

Delivering our capital programme

Securing the Supply Chain

SHETL relies heavily on the continued engagement and support of the global supply chain. To date, there have been no significant supply chain issues and SHETL's ability to deliver value for money has been robust.

It is recognised that SHETL's rapidly expanding capital programme will have an impact on the supply chain where competitors in the electricity sector, together with other competitor sectors, will challenge the continued ability to align supply chain delivery with the programme.

SHETL has embarked on a matrix alignment of the supply chain. Firstly, securing strategic partners (key suppliers, OEMs and system integrators) and secondly, contracting our key sectors of overhead lines, cables and substations in an integrated framework.

The first action is designed to give our key suppliers long term visibility of our programme, enable them to make appropriate investments and to give them a degree of certainty when engaging with SHETL. The second action is all about the early engagement of the supply chain, to assist SHETL in developing the most appropriate solutions, to drive down cost and improve overall value of the supply chain. Value for SHETL includes driving excellent health, safety and environmental performance, together with the surety of on time delivery.

SHETL however, can only assist with supply chain certainty to a point. Recent experience, where project certainty in other markets has encouraged the supply chain to support non-UK projects, has been unhelpful to developing SHETL's programme.

There remain a number of key challenges in the supply chain that require careful management by SHETL, and the industry. HVDC equipment and cable manufacture both require special attention. The global market for this equipment is strong and the supply chain limited. Both require long lead times for tendering and manufacture and require considerable investment by the OEMs to complete the tendering process. It is on that basis that it is important that project certainty is high in order that the OEMs commit to supporting SHETL and UK based projects.

We have proposed the within period determination mechanism with this objective – of providing more certainty to the supply chain – in mind.

Delivering our capital programme

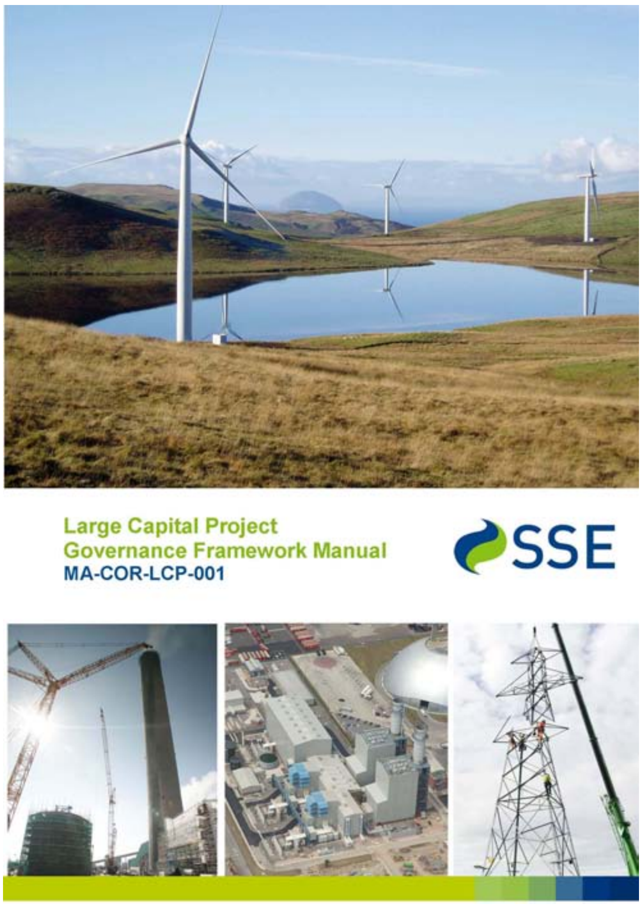
Large Capital Project Governance Framework

A key part of SHETL's strategy is to successfully deliver the required transmission investments in an efficient and economic manner.

With SHETL facing an unprecedented growth in its investment programme in order to meet the growth in renewable generation in the north of Scotland, a project governance framework was introduced in the autumn of 2010 into the business, recognising and responding to the challenge of bringing best process and governance to the transmission investment programme that is in front of the business over the next decade.

In his introduction to the Large Capital Project Governance Framework Manual, Colin Hood, Chief Operating Officer SSE, said:

"During this unique and exciting period in creating SSE's future, we have embarked on an ambitious Capital investment programme which will reshape our company and bring benefit to our shareholders and partners. The challenge for all involved is to deliver our projects safely, on time and with the level of returns committed to in our business plans. This Framework Manual will provide you with a clear structure and process to follow for project execution. Companies which demonstrate best in class performance in this area, apply their processes consistently and with rigour. It is my ambition that we have a common SSE way in this respect and that we execute projects consistently: using a common language, sharing our learning, developing our people and teams and delivering business benefits as planned."



Delivering our capital programme

The purpose of the Large Capital Project Governance Framework Manual is to ensure that all large investment projects for the SSE Group including transmission are governed, developed, approved and executed in a consistent and effective manner, with consideration of best practice in project delivery. The goal is safe, sustainable and timely execution of the large capital project portfolio, delivering business revenues and shareholder value in line with approved business plans.

The framework has been designed on the basis of people engagement, teamwork, knowledge sharing and continual improvement amongst project delivery groups and teams. It is phased with six gates at appropriate decision points, with clear, consistent deliverables for each gate. Project Governance rules are established and defined for each phase, with standard project organisational structures and key roles.

Governance Process

The process shown in **Figure 16** has five phases with gate-keeping as the project moves through the phases.

The purpose of the gates is to ensure transparency, scrutiny and appropriate approval on project development and required deliverables. As projects move through the Gates the required level of project definition and cost estimate accuracy increases. Clarity on project risks, as well as benefits will assist with business decision making. At each gate a decision is made to approve progression, put on hold or cancel the project.

Opportunity Assessment relates to developing and assessing investments necessary to meet licence requirement. This phase screens regulatory requirements; assessing the needs case and viability of technical execution. If necessary, development funds are requested during, or at the end of, this phase.

Development is the phase where selected projects are further assessed, defined and a preferred development option is selected.

Refinement is the phase where the selected option is further developed to a level which allows full assessment of the viability of technology and execution. Key requirements from this phase include gaining higher degrees of certainty on cost, programme and project risks. Execution and procurement strategies are selected and the business case is finalised. During this phase a gradual transition and transfer of responsibilities takes place between development and execution project teams. At the end of this phase, request for full capital investment is made to the appropriate Governance Review Teams.

Execution is the phase where the approved option is detail designed, procured, constructed and commissioned.

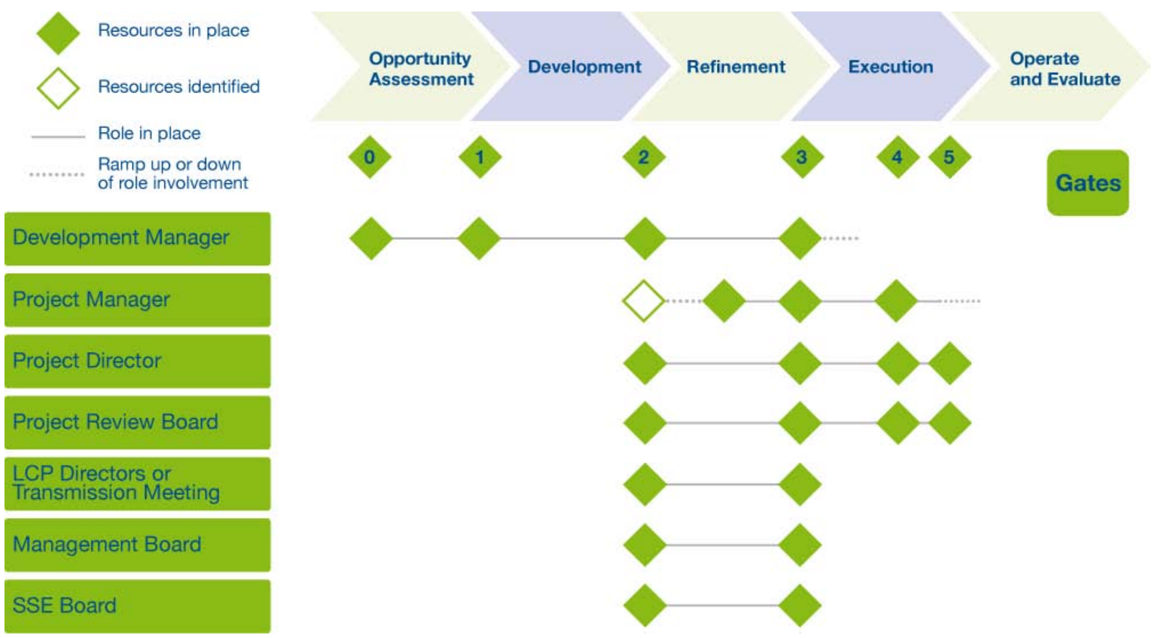
Operate and Evaluate is the phase where the asset is handed over to the system operator for operation and its performance evaluated.

Ownership Roles and Responsibilities

The establishment and longevity of governance roles in relation to gates are shown in Figure 17.

The SSE Board has authority to sanction project progression through Gates 2 and 3 for projects with a total capital investment greater than £50 million. The SSE Power Distribution Board has delegated authority to sanction project progression through Gates 2 and 3 for projects with a total capital investment less than £50 million.

Figure 17 LCP Governance Roles and Teams



Delivering our capital programme

SSE Governance Review Teams include the Transmission Meeting for SHETL's regulated projects. Project Review Boards are established by the Project Director and have a supervisory, assurance, guiding and assessing role for a project. The composition of these boards draws on key stakeholders from appropriate business areas. Project Team resource requirements are defined by the Project Manager and approved by the Project Business Unit Director. For large high risk projects a minimum project structure must be adopted by Gate 3 and key roles resourced.

Project Compliance Reviews

For high value / high risk projects, Compliance Reviews take place to ensure the project value is in line with the needs case and that all risks are being managed and opportunities exploited to the full. Compliance reviews can take place as a precursor to moving through Gates 2, 3, during the Execution Phase and after project handover to the system operator.

Risk Management Process

A Project Risk Plan is generated prior to Gate 1 and through Gate 2. The Risk Plan is maintained through Gates 3 and 4 by the Project Manager and approved by the Business or Project Director. As a minimum, the following risk areas will be considered: SHE, commercial, reputation, intellectual property, development, construction and operational.
A Risk Review Workshop is held between Gates 1 and 2, which is used to generate the initial Risk Register with mitigations. As a minimum, a further Risk Review Workshop shall be held prior to Gate 3 to update the Risk Register with mitigations and responses.

Financial Analysis and Reporting

Finance Group adopts an appraising, challenging, controlling and assurance role in the analysis and reporting of project benefits and costs. Corporate Finance undertakes independent investment appraisal up to the point of project sanction at Gate 3. Following handover (Gate 5), and a period of operation, a post investment appraisal of the project will be conducted.

Project Planning and Control

In order that a project programme and schedule is detailed to the correct level and provides transparency, the framework requires that it be constructed based on a project Work Breakdown Structure, which fully defines the scope of the project. Developing the work breakdown structure is a collaborative effort led by the Project Manager;

involving Finance, Risk, Commercial, Procurement functions and the project team of Project Engineering and Project Controls Engineers.

The level of breakdown agreed to, depends not only on planning and scheduling requirement, but also on the need for contractual and cost transparency. Based on this breakdown, a cost breakdown structure is agreed to allow budgeting and project cost management.

Following Gate 3, a measurement of programme and schedule control is established to report progress against commitments given in the needs case and approved programme.

Commercial, Insurance and Legal

To support a project's objectives to the greatest extent possible it is critical that integrated Commercial, Insurance and Legal (CIL) responses to project risks and opportunities are developed and implemented. The CIL responses shall include appropriate regulatory, commercial, procurement, insurance, contract management and dispute management approaches for the project and shall be co-ordinated through CIL Review meetings between senior individuals from each of the CIL departments (the CIL Group) and the Development or Project Manager. CIL Review meetings between the CIL Group and the Development or Project Manager are held as risks dictate as the project moves through each phase.

Conclusion

In conclusion, the purpose of the Large Capital Project Governance Framework Manual is to ensure that all large investment projects for the SSE Group are governed, developed, approved and executed in a consistent and effective manner, with consideration of best practice in project delivery.

The goal is safe, sustainable and timely execution of the large capital project portfolio, and for SHETL, the project governance framework recognises and responds to the challenge of bringing best process and governance to the transmission investment programme that is in front of the business over the next decade.

Our Network Availability Policy

Context

Transmission Owners (TOs), have an obligation to provide transmission services to the National Electricity Transmission System Operator (NETSO), as set out under the transmission licence (our Standard Licence Condition D2).

In addition, TOs have an obligation to comply with System Operator –Transmission Owner Code (STC) in accordance with Standard Licence Condition B12. Thus TOs have the obligation to make available their network assets to facilitate the safe, economic, and reliable transmission of electricity within its licensed area.

The activities of TOs can be affected significantly by factors that are outside of their control, primarily due to actions/decisions taken by the NETSO. Similarly the activities of the NETSO can be affected by TO actions.

In its role as NETSO, National Grid incurs costs when it takes actions to resolve constraints that can arise where there is insufficient capacity on the transmission system given the pattern of (scheduled) electricity generation and consumption. These constraint costs can be substantial and are, in large part, ultimately passed on to consumers.

Constraint costs are affected by the availability of the transmission network. This is, in turn, affected by "real time" activities of the TOs, for example taking equipment out of service for maintenance or refurbishment to protect the reliability and health of transmission network assets over the longer term.

Constraint costs may be reduced if the duration of these works is shortened or if works are undertaken at times of favourable energy flows (e.g. when a specific power station that would be behind a constraint is also on maintenance). TOs can also contribute to reducing constraint costs by taking actions that enable increases in circuit ratings either temporarily or permanently, which allow more power to be transferred.

To focus on actions that we, as a TO, can take which affect constraint costs without requiring the installation or upgrade of transmission network assets, we have prepared this document. Our network availability policy sets out what the NETSO, and other stakeholders, can expect from us insofar as our actions that affect the availability of the transmission network.

Our Network Availability Policy

Introduction

The object of SHETL's Network Availability Policy is to clarify what the NETSO, and other stakeholders, can expect from SHETL insofar as how our actions affect the availability of the transmission network.

Our policy sets out how we will plan and manage outages and deal with risks of over-runs. Our ultimate aim is to secure the lowest cost outcome for customers. This policy is in addition to our existing obligations under the licence and STC.

Information about system constraints

It is recognised that the Scottish TOs (SHETL and Scottish Power Transmission) do not have the same information available to them as National Grid on the likely impact of their actions on system constraints. While there are good reasons for this, which we support, this severely limits our ability to independently identify and resolve system constraints.

SHETL has therefore discussed with the NETSO the need for a Scottish TO–SO forum (bilateral or trilateral as required) that exchange relevant information. This approach will ultimately inform the ongoing development of our network availability policy, so that it can be complied with given the information available and to resolve information deficiencies where possible.

SHETL consider an SO–TO forum as essential to the successful development of an informed network availability policy. Progress on bilateral or trilateral liaison will be greatly aid coordination between the NETSO and TOs, such as through:

§ NETSO requests to the TO for voluntary improvements in its service, based on the NETSO's understanding of the latest information on the scale, location and timing of constraint costs.

§ The TO being able to offer enhanced services to the NETSO, which the NETSO could choose to take up, again based on the NETSO's understanding of constraint costs. These enhanced services could either be included, as options, in the network availability policy or developed and agreed during the price control period.

Policy Objective

The objective of this policy is to set out the principles to be applied by SHETL in seeking to agree, plan and organise transmission network construction and maintenance activities. These activities ensure that the availability, reliability and utilisation of SHETL

Our Network Availability Policy

assets is optimised having regard to the duties and obligations of transmission owners, the NETSO and end users of the services for which the assets are provided.

Our policy is to plan and organise outages to minimise the costs to customers, whilst meeting our legal, licence and regulatory output requirements to meet customer expectations. In this respect we need to take into account:

§ The cost of implementing any actual works on the transmission network which require a network outage on part of the SHETL transmission network, and
§ Potential constraint costs on the network, associated with this outage.

Prioritisation and planning of work

Over the coming decade we expect to significantly expand our network to facilitate the growth of renewable generation in the north of Scotland in order to meet national renewable energy targets. The potential scale and timing of this investment is not fixed as it depends on new generation projects proceeding. Nevertheless, our forecasts indicate that we could invest up to £6 billion in our network compared to the value of the existing business of around £450 million.

This level of investment will result in a significant increase of requested outages on the transmission network for associated construction and connection works. These outages are over and above the pressures of outages across the expanding interconnected transmission network required for essential operations, maintenance and fault repairs.

SHETL recognise that the things that we do with the NETSO to manage the system operation impact of our works are critical. However we need to reflect the increased pressure on securing system outages and the need to manage all costs directly associated with an outage, in order that these may be managed in the best interests of our customers.

Our policy assumes that critical outage “windows” will be agreed many years in advance, in particular for large capital projects.

In defining and prioritising outages, our policy is to apply the following principles:

Our Network Availability Policy

- § To ensure that the GB transmission network is operated safely and securely.
- § To ensure the development and maintenance of an efficient, co-ordinated and economical system of electricity transmission, and
- § To ensure consultation in a timely fashion with the affected network stakeholders regarding necessary coordination of activities to optimise the availability and utilisation of assets.

In meeting the above principles, our priorities in managing system outages, in order of precedence, will be:

1. The replacement, refurbishment and maintenance of transmission network assets, to ensure the ongoing safe and secure operation of the transmission network,
2. The development and reinforcement of the transmission network to minimise longer term system costs, and
3. The minimisation of short term constraints.

Policy Execution

Outage proposals are generally based on the TOs most efficient cost of delivery of its works. Schemes and implementation programmes are developed taking account of the potential for constraints, where known. The basis of assessment of the options is to minimise the overall cost to the electricity customer.

In addition, any efficient capital expenditure requirements identified by the NETSO may be included in TO plans.

To facilitate co-ordination of outages across the GB transmission system the NETSO chairs the regular Transmission Outage Planning (TOP) Forum. These forums include relevant representatives from the NETSO and the TOs as required.

Circuit outages windows will be formally agreed up to eight years in advance by the NETSO based on TO proposals and discussion at the TOP forum. Circuit outages plans will be formally agreed two years in advance, and refined at one year ahead. Annual (as a minimum) reviews of agreed outage plans and agreed outage windows (8yrs to 0yrs) will be carried out between the NETSO and TOs through the TOP Forum.

Our Network Availability Policy

The output from the TOP forum shall be an agreed outage plan for zero to two years ahead and agreed circuit outage windows for two to eight years ahead.

In the event that an outage is moved or compressed to improve the overall impact on constraint costs to customers, then the additional costs associated with the TO will be recovered from the NETSO. To move or compress this work could involve contractor / mobilisation / demobilisation, extended working days, increased manpower or alternative engineering solutions. If an outage requires to be changed, it must be rescheduled (and not cancelled) to enable the TO to deliver its necessary outputs within its required programme.

SHETL will utilise a single network outage planning tool to capture, in one location, all network outages in all timeframes. This will give the required flexibility and accuracy to meet the needs of SHETL, the NETSO and all other stakeholders in relation to co-ordinating outages in the interests of achieving the most efficient plan.

To ensure we minimise the real time costs as we continue with our works to strengthen the system, SHETL will facilitate regular stakeholder participation in programme coordination and provide transparency through publication of the programme to those stakeholders affected and those who can assist in directly influencing its efficient development.

SHETL will co-ordinate all outage planning activities centrally through a dedicated team working across new connections; investment planning, project delivery and network control. This approach will deliver a single point of contact for all stakeholders with an interest in network availability.

Through a ‘programming forum’ we will endeavour to develop levels of information sharing. In addition we will seek to ensure that the availability, reliability and utilisation of SHETL assets are optimised having due regard to our duties and obligations as a TO, the needs of the NETSO and impact on end users of the services for which the assets are provided.

The SHETL outage programming team will drive:

- liaison on the programme of circuit and equipment outages, with the NETSO and all stakeholders;
- liaise on any changes to these outages;
- aim to minimise the duration of those outages;
- bundling of outages; and,
- ensuring plans are in place to return equipment to service quickly should the need arise.

Our Network Availability Policy

Essentially, the team will ensure the most efficient placement of an outage, with regard to the information made available to SHETL through liaison with the NETSO and all other concerned stakeholders.

Critical to this will be level of interaction and timing of permissible information flow from the NETSO. This will also directly influence any timescales that will apply to requests for any changes to outage plans already agreed with the NETSO. These areas are expected to be informed through further discussion with the NETSO.

Where the NETSO requires to change an agreed outage window or an agreed outage, SHETL will consider the following options to minimise the associated constraint costs:

- Compressed working hours – shorter outages but longer overall project duration;
- Increased manpower – additional resource enabling shorter overall outage;
- Temporary increase in circuit loading – short term increased loading of circuit to reduce constraint with subsequent low loading period to minimise asset impact;
- Network reconfiguration – changes in network configuration (e.g. installation of a bypass), and
- Alternative engineering outage arrangements – outage requiring sub-optimal work procedures (e.g. work zone restrictions) and increased costs.

Where the NETSO requires to change an agreed outage window or an agreed outage, we will review all costs associated with rescheduling the outage and provide these to the NETSO. If the NETSO decides to reschedule the outage they shall recompense the SHETL for these costs, as per STCP 11-3.2. The NETSO shall also provide a preferred rescheduled date for the outage taking into account potential constraint costs.

We will publish our network availability policy and where ever possible seek to make available outage plans to those stakeholders affected and those who can assist in directly influencing its efficient development, and publish reports on our performance, on our website.

Managing risks relating to over-runs and delays to outages will be addressed through detailed return to service plans which will accompany all outages. Where SHETL incurs additional costs as a result of NETSO requested improvements to return to service times they shall be appropriately remunerated through the agreed incentive mechanism.

Our Network Availability Policy

Providing enhanced services over and above the baseline level of service

During the RIIO-T1 period, there may be opportunities for SHETL to do things that go beyond the minimum requirements of our network availability policy and which are in the interest of consumers. Opportunities may arise from a number of different sources, such as changes over time in the costs that a TO faces or innovations to asset management practices during the price control period, for example:

- Real Time Equipment monitoring;
- Thermal Monitoring;
- Sag Monitors;
- reduction of Emergency Return to Service (ERTS) times;
- short term ratings;
- temporary intertrip schemes;
- energy management schemes / constraint management across boundaries;
- temporary bypass schemes;
- hot-wiring schemes;
- Meteorological Office Ratings Enhancement (MORE);
- bringing investment forward; and
- greater use of short term ratings.

This may be driven by NETSO requests to the TO for voluntary improvements in its service, based on the NETSOs understanding of the latest information on the scale, location and timing of constraint costs. Alternatively the TO could offer enhanced services to the NETSO, which the NETSO could choose to take up, again based on the NETSOs understanding of constraint costs.

We will continue to keep opportunities for the provision of an enhanced service under review and progress such opportunities as and when they arise.