DECC - Research into GB offshore electricity transmission development. Lessons from other sectors.

FINAL REPORT

- V.2.1
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1. List of Abbreviations

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ATOC	Association of Train Operating Companies
CAISO	California Independent System Operator
CAMMESA	Compañía Administradora del Mercado Mayorista Eléctrico
CER	Commission for Energy Regulation
CREZ	Competitive Renewable Energy Zone
CPRS	Carbon Pollution Reduction Scheme
CPUC	California Public Utilities Commission
DECC	Department of Energy and Climate change
DEFRA	Department for Environment, Food and Rural Affairs
DFT	Department for Transport
DSO	Distribution System Operator
ENRE	Ente Nacional Regulador de la Electricidad
ERCOT	Electric Reliability Council of Texas
ESB	Electricity Supply Board
EWIC	East-West interconnector
FERC	Federal Energy Regulatory Commission
FREBA	Foro Regional Eléctrico de la Provincia de Buenos Aires
GB	Great Britain
GUDP	Grid Upgrade Development Plan
HLOS	High-Level Output Specification
HVDC	High Voltage Direct Current
IIP	Initial Industry Plan
ISO	Independent System Operator
ITC	Incremental Transmission Capacity
MEC	Maximum Export Capacity
O&M	Operation and Maintenance
ODIS	Offshore Development Information Statement
Ofgem	Office of the Gas and Electricity Markets
OFTO	Offshore Transmission Owner
ORR	Office of Rail Regulation
OTCP	Offshore Transmission Coordination Project
OWF	Offshore Wind Farm
PC	Public Contest
PSDH	Project for Sustainable Development of Heathrow

PSOU	Passenger Service Output Update
PT	Transmission Probability Factor
PUC	Public Utility Commission of Texas
ROSCOs	Rolling Stock Leasing Companies
RSSB	Rail Safety and Standards Board
SENE	Scale Efficient Network Extensions
SoFA	Specification Statement of Public Funds Available
SRA	Strategic Rail Authority
RETI	Renewable Energy Transmission Initiative
RGS	Railway Group Standards
RUSs	Route Utilisation Strategies
TAO	Transmission Asset Owner
TCE	The Crown Estate
TEN-E	Trans-European Energy Networks
TNUoS	Transmission Network Use of System tariffs
TOC	Train Operating Company
TPA	Third Party Access
TSO	Transmission System Operator
TSP	Transmission Service Provider
TYNDP	Ten Years Network Development Plan
UKCS	UK Continental Shelf

Introduction

The Government has set an ambitious target for the deployment of renewable energy over the next decade. By 2020, the Government expects that 15 percent of the United Kingdom's (UK) energy needs will be met from renewable sources and suggests around 30 percent of electricity may come from renewables. Offshore wind will play an important part in meeting these renewable energy targets.

The adoption of offshore wind generation has numerous advantages but one of the fundamental issues arising, is the high costs of offshore wind farms (OWF) and associated offshore transmission assets.

In addition to existing plans and extensions from Rounds 1 and 2, the Crown Estate (TCE) has tendered the development rights for up to 32,000MW of offshore wind generation under Round 3. In total, there is almost 50,000MW of capacity that is either subject to an agreement to lease (including Scottish Territorial Waters) or has already been leased. To facilitate the expansion of offshore wind, the UK Government has introduced a regulatory regime for offshore electricity transmission which effectively separates the offshore generation from the offshore transmission. Offshore transmission is a licensed activity, regulated by Ofgem (Office of the Gas and Electricity Markets), with the Offshore Transmission Owner (OFTO) licence awarded through a competitive tender process to encourage new participants and funding into the regime. The regime came in to effect in June 2010 with a transition process taking place from June 2009.

Government and Ofgem have consulted extensively on the regulatory regime and competitive tender process. The response to the joint further consultation on the enduring offshore electricity transmission regime in August 2010[1] indicated that while the competitive offshore electricity transmission regulatory regime creates no barriers to coordination, the current incentives may not be sufficient to bring about significant levels of coordination in practice. The Department of Energy and Climate change (DECC) and Ofgem are currently undertaking an Offshore Transmission Coordination Project (OTCP) to consider whether additional measures are required within the competitive offshore electricity transmission regulatory regime to further maximise the opportunities for coordination.

[1] Further consultation on the enduring offshore electricity transmission regime in August 2010 consultation included questions on the proposals for allowing a generator build option, a further opportunity to comment on the detail of the early and late OFTO appointment options, and requests to present views on whether any further actions were necessary within the offshore electricity transmission regulatory regime to facilitate the development of a coordinated onshore and offshore transmission system.

It is within the context of this project that DECC engaged SKM and sub-consultant CEPA to conduct a comparative analysis of offshore electricity transmission regulatory regimes in key countries with significant amounts of existing (and/or planned) offshore wind generation (Great Britain, Germany, Denmark, Netherlands, Ireland, France, Belgium, Sweden, USA, China) and articulate lessons learned from other relevant infrastructure sectors. The results of the project are covered in three deliverable reports:

Deliverable 1: A comparative assessment of the GB offshore electricity transmission regulatory regime with the regimes of other key countries.

Deliverable 2: An assessment of key lessons learnt from how other countries deal with coordinated electricity transmission development between the offshore developers.

Deliverable 3: Assessment of key lessons learned (which are relevant for the development of GB offshore electricity transmission systems) from how comparable infrastructure in other relevant sectors, such as oil, gas, and CCS pipelines in the UK and other countries, deal with coordinated infrastructure development between different developers.

This report is concerned with the lessons that can be learned from other sectors, both in the UK and internationally. Many of the coordination and cooperation issues that have been raised in the offshore wind sector have been encountered in other sectors. In many of these sectors evaluations of the problems linked with coordination and cooperation have been undertaken and solutions have been put in place. In several of the cases different countries or sectors have adopted different solutions to the same basic problem, allowing us to consider the strengths and weaknesses of the various approaches and under what circumstances the different solutions may be appropriate.

After developing an initial list of possible sectoral case studies we undertook a quick evaluation in terms of:

- areas of interest to this study;
- relevance of the situation faced by the sector compared to offshore wind; and
- availability of information (linked to this was also whether the relevant story was sufficiently developed to be worth including).[2]

This led us to focus on two broad case studies and then two themed multi-example case studies. These are discussed in more detail in Section 2 of this report. Then, building on the observations from Deliverable 1 and the lessons in Deliverable 2, we identified a small number of areas on

[2] Two of the possible case studies, Carbon Capture and Storage and Offshore telecoms were initially investigated but dropped owing to the level of development of the story (Carbon Capture) and the relevance of the experience (Offshore telecoms).

which to focus the lessons from other sectors. This is described in detail in Section 3 of this report. Finally, Section 4 draws together the key findings of this study and their implications for market-led systems like that in GB.

A series of annexes provides more detailed supporting information on the case studies.

2. Case study overview

This section provides an introduction to each of the case studies, including their relevance and key characteristics. As noted in the Introduction, few case studies are able to address all the issues that have been raised through our consideration of coordination in Deliverables 1 and 2; rather different elements are high-lighted by individual cases. We have also grouped shorter case studies under broad headings; later in this section we explain both the relevance of the broader heading as well as the individual cases.

Table 1 sets out the sectors considered and their relevance to the coordination concern addressed in this overall study. A sector which is considered to be relevant is highlighted with a "yes".

- **Table 1 Overview of the relevance of the sector case studies**

Case	Planning/ design/ information	Standardisation	Shared assets	Funding/User Commitment	Anticipatory investment
Rail	Yes	Yes	Yes	Yes	
Offshore oil & gas	Yes	Yes	Yes	Yes	Yes
Onshore electricity transmission					
Ireland	Yes	Yes	Yes	Yes	
Argentina	Yes			Yes	
Texas	Yes	Yes	Yes		Yes
Open season	Yes	Yes	Yes	Yes	
HVDC[3] Interconnectors		Yes	Yes	Yes	Yes
Australia				Yes	Yes
Market mechanisms					
GB gas entry	Yes		Yes	Yes	Yes
UK cable TV					Yes

Note, the colours in Table 1 represent our view of the case studies as to whether the experience is supportive/facilitative of coordination (green), examples of where coordination has not taken place, or did not lead to the expected outcome (red) or mixed/uncertain (blue).

We now summarise each of the case studies.

[3] High Voltage Direct Current

2.1. Rail

The reforms of the GB rail system in the mid-1990s introduced significant market pressure and greater transparency to different elements of the industry structure. This included both vertical and horizontal separation built around a national infrastructure provider (but where even the maintenance and construction activities were contracted out). This model was designed to allow information flows between market participants and consequently improve responsiveness to customer demand against the perceived problems inherent in the previous national vertically integrated monopoly of British Rail.

A lack of coordination between elements of the industry has led to poor decisions, inefficiency and higher costs for both customers and government (who provides the vast majority of the revenue for the sector). This is exemplified by observations like rolling stock being route specific so limiting the ability to better deploy assets in other areas when they are updated or no longer fully utilised. Consequently over the past decade or so it has become increasingly obvious that the chosen model has not delivered value for money. The McNulty[4] review, completed earlier this year, considered ways in which incentives between market segments could be better aligned and other actions to improve coordination in the sector.

In addition, options for different stakeholders to fund elements of the investment have existed. One of the key examples of this, Project Evergreen, high-lights issues around the user commitment and funding question.

Given the situation of the GB rail system as discussed above it provides a good comparator for many of the issues being faced in the offshore wind industry at the moment. Further, the recommendations of the McNulty Value for Money study provide an example of the types of response to improving coordination that can be considered for a market with many different actors.

2.2. Offshore oil and gas

During the 1970s and 1980s there was significant development of coordinated oil and gas pipelines to deliver North Sea resources to GB. These developments were built around major oil and gas fields which were able to support the development of key infrastructure while also allowing sharing of resources between the small numbers of offshore players.

More recently coordination issues have arisen around the development of new infrastructure to service the smaller fields that are now being developed. DECC and the industry have been working together to develop coordinated responses and elements of the industry are trying to work together to share facilities and develop common information/assessments of infrastructure needs.

[4] http://www.rail-reg.gov.uk/upload/pdf/rail-vfm-summary-report-may11.pdf

While the experience from the 1970s and 1980s demonstrates that offshore coordination is possible, the more recent experience built around smaller fields and a clear need to share infrastructure resembles much more closely the situation facing the offshore wind industry. Further, the fact that coordination has proven difficult demonstrates that issues of cooperation and coordination are not limited to the offshore wind industry. The developments around government-industry working groups to facilitate coordination and possible joint/common work to inform decisions provides interesting examples of actions that can be taken to facilitate coordination.

2.3. Onshore transmission

While the focus of the coordination debate is offshore transmission, many of the issues being addressed are ones that are equally valid for onshore transmission. Further, given the maturity of onshore transmission, there are numerous examples where the issues have already been addressed. The mini-cases under this general theme capture these points and individually high-light one or two of the key themes. The mini-case studies are discussed briefly below.

2.3.1. Ireland

Ireland is in the process of developing significant renewable generation capacity to meet an ambitious Government target. The development of the transmission network to support this new generation capacity is primarily the responsibility of EirGrid, the transmission system operator (TSO). Planning and initial development of transmission is the responsibility of EirGrid although the delivery of the final construction and operation is passed to ESB (Electricity Supply Board) Networks, the transmission asset owner (TAO).

In Ireland, a “grouping/batching” or “gate” based approach to coordinating new renewable generation based connections has been adopted. This allows the TSO an opportunity to better plan the efficient provision of the new connections. The process is now in its third iteration. There are also some interesting aspects linked to shared assets and the way in which they are funded and how additional connections then contribute to the original funders.

This approach is of relevance to the offshore wind coordination question since it offers one possible way in which projects can be grouped, not unlike the German system. It also offers an example of the way in which initial funders/developers can be rewarded for over-sizing shared assets (or coping with the under-utilisation of shared assets during initial years).

2.3.2. Argentina

Argentina gas developed a very specific customer driven approach to the expansion to the transmission network. Customers, whether major final users or suppliers/aggregators, are responsible for ensuring sufficient user coordination and commitment to support the development

of new lines. Further, the customers are then responsible for organising the provision of the new transmission line.

This is of interest because it both reflects the way in which user commitment can be mobilised, in a sense through a customer driven process not unlike open season which is discussed further below, and coordination achieved. Further, the fact that the development of the line is then outsourced is not that dissimilar to the way that GB offshore transmission has been handled through the OFTO regime. This approach can also be considered a market based system owing to the way that customers are expected to coordinate and then outsource the operations and consequently it could also be included under that theme. However, given that it is an onshore transmission example we have included it under this sectoral/theme heading.

2.3.3. Texas

Anticipatory investment is an issue that several jurisdictions have considered. We consider two examples under this theme, Texas and Australia. Texas is a state with significant renewable generation potential. In 2005 an approach to anticipatory investment was adopted where potential wind generation zones are identified and then connected to the grid prior to any wind farms being developed. This is an extreme form of anticipatory investment (sometimes referred to as “build it and they will come”) and the only example of its kind that we know from the electricity transmission sector.

Given the uniqueness of this example it provides a useful test of one type of anticipatory investment. While it may be extreme it helps elucidate some of issues around anticipatory investment which is one of the key concerns for offshore wind.

2.3.4. Open season

This is an approach to user coordination that requires developers of new transmission facilities to offer third party users an opportunity to request additional capacity to be included in the new facility. The approach has been used extensively in the US and is also used in some continental European countries for both electricity and gas transmission lines.

As an example of developer led coordination it helps illustrate a process that could be followed by offshore wind developers to test for the need for shared assets and could provide an approach that is appropriate for a market led network that expands in a localised, area by area manner (rather than the more centralised or TSO led gate approach covered by the Irish example).

2.3.5. HVDC Interconnectors

Interconnections between jurisdictions are becoming increasingly common with several key examples in Europe. Further, the use of HVDC to facilitate the movement of significant amounts

of power has raised issues around technological issues and standardisation. These interconnectors raise several issues that are similar to those faced by offshore transmission – coordination between the jurisdictions, sharing of assets and possible alternative models of ownership and operation. HVDC interconnectors can also be considered anticipatory investment in certain circumstances – this is especially true for Merchant Transmission lines. Further, some forms of coordination and sharing between OWFs could be considered as interconnections and consequently the lessons from the development of "pure" interconnections could illustrate some of the issues within offshore coordination.

2.3.6. Australia

As noted above, we consider two examples of anticipatory investment within onshore transmission in this sectoral themed case study. The first was Texas and the second is Australia. Recently a proposal was made in Australia to allow anticipatory investment in terms of over-sizing transmission capacity for new wind farms so that future developments can occur at lower cost (this is the alternative form of anticipatory investment to that considered in Texas). The proposal was consulted on with various options for user commitment thresholds and risk allocation mixes being considered. The final decision was to not make any changes from the current situation, but there are clear incentives for developers to build additional early capacity.

This example is useful as it:

- illustrates a more incremental, less speculative form of anticipatory investment;
- provides an overview of how another jurisdiction has considered the pros and cons of the over-sizing of investment approach to anticipatory investment; and
- provides an example of an incentive based approach to facilitating anticipatory investment which only penalises final customers if actual sharing of assets doesn't take place.

This is a useful counter to the Texas example and helps clarify the choices that jurisdictions can make.

2.4. Market mechanisms

A second general theme has been considered which is based around the ways in which markets are used in different sectors to coordinate users, identify investments and develop user commitment. Two key mini-case studies exist within this theme and they are described briefly below.

2.4.1. Gas entry

In response to concerns about excess demand for gas entry and the problems this would cause for meeting peak winter demand, a new regime for gas entry was developed in GB late in the 1990s

and early 2000s. This approach, based around long-term auctions where users could book capacity up to 17 years in the future was developed so that user requirements could be assessed.

If auction prices were above the long run marginal cost of new entry capacity and at least 50% of the incremental capacity was booked through the auction, the new capacity could be developed. Significant investment has taken place, much of it in the five year period from 2005, which met the concerns at the time about ensuring sufficient capacity to meet winter peak demand (something that had been questioned through some previous events). Clearly this regime was successful and sufficient capacity now exists, however, as supply sources change we cannot rule out the need for further supply capacity.

This example illustrates some of the possible solutions to coordination and cooperation issues in the offshore wind sector. The role of auctions, which could be considered another form of open season but one that is TSO led, to identify investment needs over the medium to long-term is another possible coordination tool that can work in a market-led environment. The degree of user commitment required is also an example of a GB system requiring less than 100% commitment with the remaining cost being socialised, unlike the offshore transmission system where 100% commitment is required. Consequently this provides a useful alternative approach whose impact can be assessed relative to the offshore transmission regime.

2.4.2. Cable television

The UK cable TV infrastructure was developed during the 1980s and 1990s, primarily through roll out of infrastructure in franchised areas. While companies may hold an exclusive franchise, competition (from terrestrial TV, telecommunications developments through video on demand over copper wire and satellite based services) meant that investment was made at risk and can be considered an example of significant anticipatory investment (of the “build it and they will come” type). Also, very high upfront investment followed by a slow build-up of revenue meant that financeability became a significant issue with market restructuring a result and the growth of a small number of major players replacing the separate local franchised operators.

The direct relevance of this example for offshore wind is limited. However, as an extreme example of anticipatory investment funded by investors at their own risk it is informative about how such an approach can influence investment and market structure/ownership over time. It also provides an interesting example of what scale of anticipatory investment companies are willing to make.

3. Lessons learned

Five key themes have been noted in Table 1 as to areas where coordination and cooperation examples are found in the case studies. Each of the sub-headings is considered in this section, with their relevance for the GB offshore transmission regime being developed.

3.1. Planning/design/information

The first area to consider is that of coordination and cooperation around planning, design and information. If we initially focus on the first two issues, planning and design, three of the case studies help illustrate this point.

- In Ireland the batching of new renewable projects into "Gates" and then being able to plan onshore transmission expansion projects for facilitating the generation provides a good example of the way in which planning can be coordinated. This is not that different to the German offshore transmission regime although the Irish system occurs much less frequently. The question of timing of batches is interesting – anecdotal evidence from Ireland suggests that the relatively ad hoc nature of the system means that projects may miss batch closing dates and then suffer from the uncertainty of when the next batch occurs. The German six monthly system clearly overcomes this concern but possibly at the cost of too frequent batches (at least for systems smaller than the German one).
- Open season based systems offer a similar way of coordinating the planning and design of the system but in a more responsive/ad hoc manner than the formal gate process – the Argentinean electricity transmission expansion process is another form of this. While this process is dependent on future users identifying their needs and committing to the new facility, it does offer more flexibility for systems which are more market led. Further, since a new project would not be stopped from occurring even if an open season process had recently taken place the approach does not suffer from one of the drawbacks associated with the batch process. Of course, some form of incentive to be involved in the open season process would be required for it to be encouraged.
- The planning and design of offshore oil and gas networks in the North Sea has become more of an issue as developments shift to smaller fields. Various approaches to greater planning and design have been used, including government-industry working groups. While these may not have led to specific outcomes, they do hint at ways in which greater coordination and cooperation can be supported.

If appropriate it should be possible to combine one or more of these planning and design approaches with the existing British approach to offshore transmission. Working groups and more formalised opportunities for coordinating the planning and design of offshore systems ought to be possible.

The final aspect of this issue is that of information. One of the core aspects of planning and design is information flow. In GB an Offshore Development Information Statement (ODIS), which is similar to the seven year statement used for onshore electricity transmission, has been put in place for offshore transmission. Other sectors provide further examples of types of information flow that could be supportive of coordination and cooperation.

- In the rail sector a new long-term, 25 year, view of the future structure of the industry has been developed as a tool for helping coordinate and plan the shorter five-year horizon business plans that have dominated investment since the reform in the mid-1990s. (It should be noted that the water sector in England & Wales introduced a new 25 year strategic direction statement as an input to the last price review.)
- PILOT, the joint government industry working group for the oil and gas industry has discussed a possible role with respect to it jointly undertaking research on infrastructure needs which would then be provided as common information for all possible stakeholders.
- Several of the electricity transmission mini-case studies, especially Argentina and the open season approach, are very information dependent. For other customers to become involved they require sufficient information to be placed in the public domain so that an assessment of whether involvement in the project is appropriate.

As the cases demonstrate, options to improve information flow could be either centrally provided, either by the TSO or some other appropriate agency, or left to specific project developers. Both types of information may be needed and could build on existing information sources, such as ODIS in GB. Of course, information systems suffer from the problems of potentially stifling innovation or delaying choice as information is collected, collated and published as “formal” views. As such, it is important for information to be facilitative but not deterministic.

To summarise this section:

- planning and coordination issues can be addressed through various processes:
  - batch based systems can offer a simple way for some form of central agency or designated body to coordinate on a regional or national basis but owing to the need to hold specific timed gates or batches there is a risk that projects will miss a batch and suffer a delay;
  - open season type approaches offer a way of forcing marked-led systems to test whether other potential users exist and to provide a way in which project based coordination occur but clearly loses the possibility of more regional coordination; and
  - coordination can be facilitated through industry/government workshops. While this can be an alternative to choosing a specific agency to lead national or regional coordination it also suffers from the fact that decisions may be difficult to achieve;

- information is key to ensuring the best possible decisions can be taken with respect to planning and coordination:
  - long-term plans can provide useful framing scenarios within which decisions are taken;
  - short-term plans can be important in signalling where development is occurring, the facilitative investments necessary etc; and
  - such plans have to be facilitative and informative but not straight-jacketing/ deterministic.

3.2. Shared assets

Ensuring coordination between users so that economies of scale and scope are achieved through the sharing of assets is central to the delivery of any possible benefits of coordination and cooperation. Examples of sharing assets include:

- The necessity for new oil and gas pipelines in the North Sea to be shared so that the smaller fields that are now being developed are economic. While sharing is necessary, coordination has proven harder than expected with a more significant role for the government, through DECC, than was the case when larger fields were being developing in the 1970s and 1980s. Since there is an economic imperative for the companies to cooperate it appears that this is starting to occur, but less rapidly than might have been expected.
- The Irish approach to coordinating rounds of onshore renewable generation is an example of a process by which sharing of assets/economies of scale can be achieved without a fully centralised system being put in place. The Gate based system allows a grouping of projects and subsequently more appropriate transmission investment decisions than if they were considered on a project-by-project basis. In some respects this is not that different to the German approach to offshore transmission but happens less frequently and so may be better placed to gather projects together (although it may then be less responsive – but that may also be a feature of a smaller system like Ireland's than the larger German one).
- A final way in which sharing of assets can be encouraged is the requirement to have an open season process as part of any new transmission development. This is less comprehensive than the Gate-like process in Ireland since the open season is based around a specific new transmission facility development, but it may be a better process for handling discrete developments in different areas. Obviously the process slows down the approval process but it should ensure that projects are identified appropriately – especially if there is some form of penalty linked to developing an additional transmission facility within a specified time period is put in place.

What is clear is that there are processes that can be used to help ensure that coordination and cooperation through asset sharing takes place allowing a benefit for consumers. Some of these may be applicable to offshore transmission – for example the role that DECC could take in an industry-government working group and also consideration of some form of localised Gate or open season process. There do, however, need to be incentives for sharing assets, this links with the discussion about anticipatory investment later in this section.

Given the role that open season as "gates" (as a form of batching projects) can play for both planning and sharing assets a further discussion of the possible role for these types of approach is provided at the end of this section. The strengths and weaknesses of the various approaches were discussed in detail in Section 3.1 and so are not repeated here.

3.3. Funding and user commitment

The examples of funding and user commitment, which is normally in the form of guarantees or direct funding of investment although it can be based on meeting actions or other criteria (for example in Germany electricity transmission based around contracts being signed etc), illustrate what is possible under different circumstances. Unlike some other sectors, offshore transmission in GB requires full user commitment – this is currently under review as part of the CMP192 process.[5] Some of the relevant examples include:

- The socialisation of costs seen across much of continental Europe for onshore transmission has led to provision of transmission services for generation, especially wind farms. This is exemplified by the example of Spain where significant onshore wind farm development has been supported through, among other aspects of the renewables regime, the regulatory regime built around full socialisation of connection costs. Of course, this is potentially at the expense of electricity customers if the lack of geographic price signals for generation (the effect of full socialisation) leads to inefficient generation development.
- Gas entry in GB offers an interesting example of a mixed system. User commitment is required, but it is 50% of the capacity, with the remaining 50% being socialised. Evidence of investment actually undertaken and anecdotal evidence about user attitudes suggest that this lower level of user commitment was important for investment decisions. 50% user commitment is not unusual as a trigger – it is higher than that seen in Argentina.
- Two other examples provide different approaches to the problem of shared, or potentially shared, assets being pre-funded by one or more users. In the GB rail regime where a stakeholder funds and develops a project they will not necessarily benefit if additional unexpected users arise in the future. Project Evergreen, the development of enhanced

[5] See comments in the July 2011 minutes to the OTCG, available from the Ofgem website.

capacity between Oxford and London through the Chilterns franchise, is an example of this. The train operating company (TOC) was awarded an extended franchise on the basis of funding the investments for Project Evergreen which is now into its third phase. However, although meant to be funded by the TOC any additional revenues from selling surplus capacity to third parties was to be retained by Network Rail, the main infrastructure company, rather than the TOC. Irish electricity transmission provides an alternative example where, if an asset has been funded by one or more users and a new user starts to share the assets within 10 years of their development then a contribution payment towards the investment is made to the original funders.

Overall, these examples show that changing the level of user commitment could facilitate a change in attitude to combining projects and cooperating. Socialisation of costs is clearly a possibility and could be linked to the more general considerations that are currently underway about the onshore transmission mix of load and demand as part of Ofgem's Project TransmiT. Of course, there is a potential risk with the socialisation of costs which is that inefficient decisions are taken and that stranded costs occur. While fully stranded assets may be unusual it is possible to believe that some stranded costs occur – when costs are socialised this means that the risk is being borne by consumers rather than developers.[6]

3.4. Anticipatory investment

Four specific examples of anticipatory investment are considered below, the first two are from onshore transmission while the third and fourth are from completely different sectors. It should be remembered that there are multiple types of anticipatory investment, specifically:

- completely speculative anticipatory investment where facilities are provided prior to any projects that would utilise the assets have been announced; and
- over-sizing of facilities that are being provided for a specific announced project.

Both these types of anticipatory investment are relevant for British offshore transmission.

The relevant other sector cases are:

- The recent consultation in Australia on whether anticipatory investment, in terms of over-sizing transmission facilities is interesting. The consultation compared variants of two basic approaches:
  - a mix of incentives with risk retained by the developer; or

[6] Whether socialisation of some of the costs leads to a lower cost of funding for the developer and consequently lower "business as usual" costs for consumers needs to be traded off against this risk of consumers paying for stranded costs.

– protection against stranding (through the socialisation of costs) and the risk that customers would face significant additional costs (as these may be very long transmission lines).

The final decision focused on incentives rather than socialisation. Developers can over-size facilities if they wish, at their risk. There is, however, an upside provided through the incentives. If new generators choose to avail themselves of the existing over-sized facilities, they can negotiate a price with the owner of the existing infrastructure that lies between the sunk value of the incremental investment and the stand-alone cost of connection. Under the regulatory regime customers will pay the cost of a stand-alone connection – that is believed to provide the developer with the incentive for anticipatory investment as they have the opportunity to push for an access charge from the new generator in excess of the incremental cost of the over-sizing of the initial investment.[7]

- An example of the broader and riskier version of anticipatory investment is provided by Texas (and California). The development of new transmission lines without any projects clearly can send a strong signal about the desire to develop new generation facilities. If the sites that are identified are clearly ones that will be utilised at some point in the future then the costs are limited to the funding costs for the years until generation develops and the potential risk that the capacity developed is insufficient to fully utilise the anticipatory investment.
- The rail sector in Britain also provides an example of anticipatory investment in terms of over-sizing facilities. If a rail operating company (passenger or freight) request an expansion of capacity, they are able to over-size the capacity and then resell the surplus capacity to other operating companies if the opportunity arises – although as shown by the Project Evergreen example the initial funder will not benefit from the sale of this additional capacity. A similar sort of approach was proposed for the Project for Sustainable Development of Heathrow (PSDH – which covered terminal six and runway three) where the airlines that would pre-fund the investment would receive financial rights if the capacity was allocated to other airlines in the future. These examples show the close relationship between the funding/user commitment issue and anticipatory investment (if the developer does not fund the anticipatory investment).
- As noted in section 2, the development of the UK cable TV industry could be considered one of the most significant examples of anticipatory investment that took place in the 1980s and 1990s. While ultimately successful in terms of service delivered, financially the sector is unlikely to be considered a success. Significant restructuring was required to

[7] This consultation was completed in 2011 and it will be interesting to see how the industry responds to this. While the rules are clear there are no examples yet of how the industry will act.

allow a viable industry to develop with sunk investments being written-off through the take-over process. The relevance to offshore transmission is primarily around the fact that while this was a major source of anticipatory investment it was done very much at risk. It is unlikely that offshore transmission would develop in this way, although it is clear that the markets were willing to fund this investment with a much higher risk profile than would be expected to exist with offshore electricity.

Anticipatory investment is clearly possible, with relevant electricity transmission examples existing. However, what is also clear is that unique circumstances, like the UK cable TV situation, need to exist for market based funding to occur with the anticipatory investment at risk. For anticipatory investment to be funded by developers there needs to be the possibility of a significant upside through the allocation of residual rights – such as being able to capture the difference between a stand-alone and shared asset based approach. It is far from clear that these conditions exist in the GB offshore electricity transmission sector, although there may be some circumstances around zonal development that could be made sufficiently attractive through incentives for anticipatory investment to be developer funded.

It is more likely, however, for anticipatory investment to occur when some form of socialisation of cost or possibly risk is provided. Whether this needs to be full socialisation, as seen in some of the continental electricity transmission systems, or partial, see for example the GB gas entry and Argentinean onshore electricity transmission user commitment requirements of 50% or less, is an open question.

Arguments for incentive based anticipatory investment can be found – the recent Australian decision over onshore electricity transmission being an example – but these are unproven. It would also require a strong regulatory commitment to allowing the stand-alone charge to be levied even when sharing of assets occurs for the incentives to be viewed as meaningful. The best GB examples have included some socialisation of costs but, as noted earlier, this comes at the risk of stranded costs being borne by consumers in the future.

3.5. Standardisation

There are some potential issues around standardisation – arising from the lack of coordination and technology development – for offshore electricity transmission. Some aspects linked to coordination have been addressed elsewhere in this section – if a coordinated development occurs questions about choice of technology (HVDC versus AC[8] for example) will naturally be taken care of. Other technology issues, such as whether required technology will be developed do raise

[8] Alternating current

interesting issues (possible coordination of industry research etc) but are really outside the scope of this consideration.[9]

Standardisation through coordination (but not necessarily technology) is less of an issue in other sectors. There is, however, one coordination example from the case studies that is relevant. In the rail sector in Britain there is one major standardisation issue – that of rolling stock. By making rolling stock route specific inefficient utilisation of stock has occurred and consequently costs are greater than would otherwise be necessary. Greater coordination and standardisation of stock would allow more efficient use and reallocation between routes. In part this ought to have occurred, the three rolling stock leasing companies (ROSCOs) responsible for the majority of stock should have been incentivised to ensure that stock was standardised. However, that was not the case, the incentives on the operating companies to have standardised stock were low (or non-existent) and consequently the incentives on the ROSCOs did not work. Better coordination is planned for the future so that this problem can be overcome.

This provides an example of the problems of coordination standardisation and one way in which it can be overcome. Clearly there is always the risk of losing innovation if unnecessary standardisation takes place, although there is also clearly a cost trade-off and clarity about what types of innovation are useful/necessary and which could lead to costs borne by consumers and which should be at the developers expense is a difficult area. This is something that was considered by DEFRA's (Department for Environment, Food and Rural Affairs) Cave review for the water industry in GB. The solutions to supporting innovation are not that dissimilar to those considered in the energy sector, possible development funds which companies and third parties can bid for, more supportive industry structures etc.

3.6. Further evaluation of open season and "batch" based coordination

Several of the key differences concerning coordination and cooperation between a TSO-led (or situations where there is more centralisation of decisions) and market-led approaches can be seen in the comparison of "gates" (or batch based systems) and project specific approaches like open season. Table 2 provides a comparison of certain aspects of the two approaches.

The comparison in the table summarises what we believe are the key difference between the two broad approaches. What is clear is that the project based approaches like open season are more linked to market-led approaches while gate or batch based systems are more linked to the TSO-led approaches. What is also clear is that while a project based system ought to be able to achieve the

[9] There have been circumstances where industry bodies are created to support basic technology development. For example, UKWIR, the UK Water Industry Research agency acts as a route by which technology and processes can be jointly developed.

best design and utilisation of the specific asset it does not necessarily lead to the best design and utilisation of the overall network. So, the degree of coordination and cooperation is likely to be more limited under the open season based approach – although it retains the other benefits of the marked-led based approach.

- **Table 2 Comparison of gates and open season**

Approach	Characteristics of the infrastructure provided	Coordination issues
Open season Focus is on a single piece of infrastructure	Fixed infrastructure option being considered (based on the primary project) Option is to achieve the best design and utilisation of that asset	Market-led as the developer (or some similar project focused stakeholder) leads the process. Information issues only relate to the specific project.
Gates Focus is on the national system (although possibly a regional approach could also be used)	All infrastructure options are being considered (based on the national or regional system). So best choice of infrastructure option should be taken. Then option is to achieve the best design and utilisation of the whole system.	TSO-led as this becomes a part of the central requirement for infrastructure provision. Could become a part of a national/ regional information system.

4. Summary

What is clear from the case studies from other sectors is that:

1) coordination issues are not unusual, especially in market-led systems;
2) but possible solutions do exist and these require appropriate:
   a) processes to be put in place; and
   b) incentives that are aligned between stakeholders.

Several of the British case studies illustrate the fact that market-led systems often face coordination problems – rail and oil and gas being good examples. However, they also illustrate attempts to address the problem through the latter bullet. In both sectors the role for government is changing with it needing to either take a greater role in facilitating coordination and cooperation or tasking some other agency/organisation to do this.

When considering the case studies the following three questions need to be considered:

- Possible mechanisms to bring about coordination and cooperation include market-led, TSO-led and voluntary based systems. Which is appropriate and when? As discussed in Section 3, open season and other project based coordination approaches are more appropriate for market-led systems although there is a cost in terms of possible broader aspects of coordination that might be lost – as described in section 3.6.
- Do coordinated systems naturally occur or do they more often relay on a central "facilitator" which may in turn be a created agency (such as a regulator) or a rule (possibly enshrined in legislation) that allocates responsibility for this facilitator rule? The answer to this is quite clear, a facilitator is needed and this role needs to be clearly allocated, although the basis on which it is allocated is more flexible. And
- Are there examples of excess coordination? Again, the answer to this is yes. Two examples can be considered – the Texas approach to anticipatory investment is bound to raise concerns about stranded assets, while the GB gas entry auction approach could arguably be seen as having led to excess capacity.

The implications for offshore transmission are quite clear. Specifically:

- routes by which planning and design coordination should be created exist and could be based around industry-government working groups and/or enhanced information processes like open season;
- where there are clear benefits from sharing assets there should be sufficiently strong incentives or TSO/central authority leadership to build on the processes described above;

- these incentives can also be linked to providing anticipatory investment, at least in terms of over-sizing facilities. Whether anticipatory investment in terms of building prior to any projects should be encouraged is a different question and raises the real concern about the risk of stranded costs; and
- whether the investment is funded by users, developers or socialised may be a separate issue, although the right mix of funding is likely to be one which captures elements of all three possible sources, as shown by examples like gas entry. But getting the right mix will affect the overall level of incentive and the consequent risk of over-investment.

Overall, for market-led based systems like the GB offshore wind regime, there are some clear lessons as to how coordination and cooperation can be facilitated if that is felt to be appropriate. To further encourage coordination within a market-led approach, any additions should be incremental and build on the existing approach.

Central to the incremental additions would be a system to encourage information flow and user commitment to facilitate shared assets. Some form of open season type approach ought to be able to deliver this. To encourage this some form of incentive, possibly like the Australian approach based around allowing the stand-alone cost even when assets are shared (although this could be time bound to share the benefit with customers).

A similar outcome ought to be possible through the socialisation of some of the offshore costs – although what proportion should be socialised is less clear. This would be an alternative approach to an incentive based open season type approach.

Appendix A GB Rail

A.1 Introduction

The GB rail industry has developed over the course of nearly two hundred years. Nonetheless, it remains in a constant state of change, needing to reflect shifting population/transport patterns, accommodate the needs of a variety of rail users and deliver government's social goals.

The monopoly nature of the infrastructure, long lead times and high cost mean that anticipation and coordinated planning of shared future demands is essential. The separation of infrastructure, rolling stock and services provision has created particular coordination problems in the industry recently. The May 2011 McNulty Report[10] on barriers to improving value for money in the industry points the finger at a lack of constructive cooperation in a number of areas.

This case study examines the GB rail sector, providing information on:

- industry structure and regulatory regime;
- overall system planning;
- sharing of assets;
- pre-commitment and anticipatory investment;
- standardisation; and
- a summary of the industry's investment delivery performance.

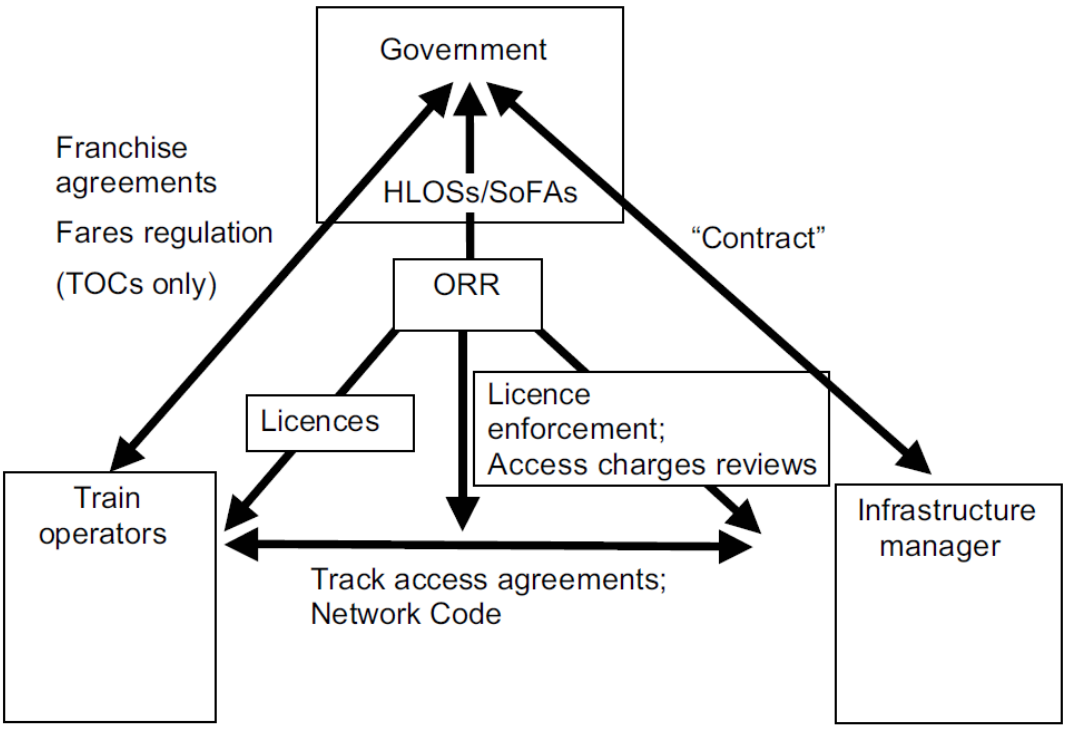
Two appendices provide more specific detail on two issues discussed in this annex.

A.2 Rail industry structure and regulatory regime

Rail is a complex industry in Britain, developed through a mixture of private and public initiatives, and subjected to periodic waves of reform. The current structure includes regional franchises, freight and open access operators sharing capacity on rail largely owned and maintained by Network Rail. The industry receives a strong steer from government (including the devolved governments), matching the level of financial support it provides.

Figure 1 below provides a simplified illustration of the industry structure and roles.

[10] McNulty (2011) "Realising the potential of GB rail: Report of the Rail Value for Money Study" Department for Transport http://www.rail-reg.gov.uk/upload/pdf/rail-vfm-detailed-report-may11.pdf



- **Figure 1 Structure of the rail industry**[11]

The structures shown above in Figure 1 are summarised in the following sections.

A.2.1 Role of government

While GB rail is privatised, it has a large degree of control from central government via the Department for Transport (DFT), the Office of Rail Regulation (ORR) and the Rail Safety and Standards Board (RSSB). The government, through DFT, "provide strategic direction" and "procure rail services that only it can specify."[12] This role includes franchise competitions, monitoring and enforcement. Transport Scotland, the Welsh Assembly, Transport for London and Merseytravel also have input in their respective jurisdictions. ORR is the industry economic and safety regulator. ORR control periodic access charge reviews and control the allocation of capacity. RSSB was established as a not-for-profit company in 2003 by industry stakeholders to improve health and safety performance of the railways.[13]

[11] Source: McNulty Report (2011)
[12] http://www.dft.gov.uk/rail
[13] See RSSB website http://www.rssb.co.uk/

A.2.2 Rail users

Rail users include franchised operators, open access operators and freight operators.

The majority of passenger services are provided by franchisees. These operators have long-term contracts granting various rights but also require specified outputs such as cleanliness, standards of facilities, and punctuality of services. Some franchises are made viable through DFT subsidy, whereas others may be "cash-positive" for some or all the contract and pay DFT for the right to operate.

Franchise agreements are not uniform. For example, to extend its minimum franchise term, Chiltern Railways was required to propose infrastructure investments, such as its Evergreen projects. Chiltern bear the project cost and delivery risk on these projects, but can transfer the assets to Network Rail on completion or receive a guarantee that a future franchisee's usage level or that they will buy the assets at net book value.[14]

Open access operators provide services without a franchise or concession. They apply to ORR for access rights and to Network Rail for train paths.[15]

A.2.3 Infrastructure manager

Network Rail is the infrastructure manager, owning and operating mainline track and signalling infrastructure. They are responsible for the management and development of the infrastructure. They must ensure that "all schemes are compatible and integrated with existing railway operations" and be confident that "when schemes are completed, they can be operated and maintained safely, reliably, efficiently and cost-effectively."[16]

They were set up by government following the "rail administration" of Railtrack as a company limited by guarantee and have a licence regulated by ORR. Network Rail recover their costs through a network grant from government (GBP 3.3b in CP4 per annum) (65 percent CP4 revenue) and regulated access charges (27 percent CP4 revenue). Figure 2 below provides a summary of CP4 access charges.

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[14] http://assets.dft.gov.uk/publications/pgr-rail-passenger-franchises-historicaldata-pdf/report.pdf
[15] Hull trains and Grand Central are the only current open access operators.
[16] http://www.networkrail.co.uk/aspx/4171.aspx

Charge	User					Estimated annual CP4 income (£millions)	Recovers	Unit of charge
	TOC	Open Access	Freight for coal services	Freight for spent nuclear fuel	Other freight			
Variable usage charge	Yes					183	Maintenance and renewals costs that vary with traffic	Per vehicle mile (or by weight for freight)
Capacity charge						155	Costs to Network Rail from increased network traffic	Per actual train mile operated
Electrification asset usage charge	All running electrically powered services					7	Maintenance and renewals costs of electrification assets that vary with traffic	Per kWh
Traction electricity charge						181	Costs Network Rail faces in providing electricity for traction purposes to train operators	Per kWh
Coal spillage charge			Yes			2	Costs from coal spillage	Uplift on charges for vehicles carrying coal
Freight only line charge			Yes			4	Fixed costs associated with freight-only lines	Uplift on variable charges
Fixed track access charge	Yes					869	Remaining income required to meet Network Rail's total revenue commitment	Allocated between operators by vehicle mileage

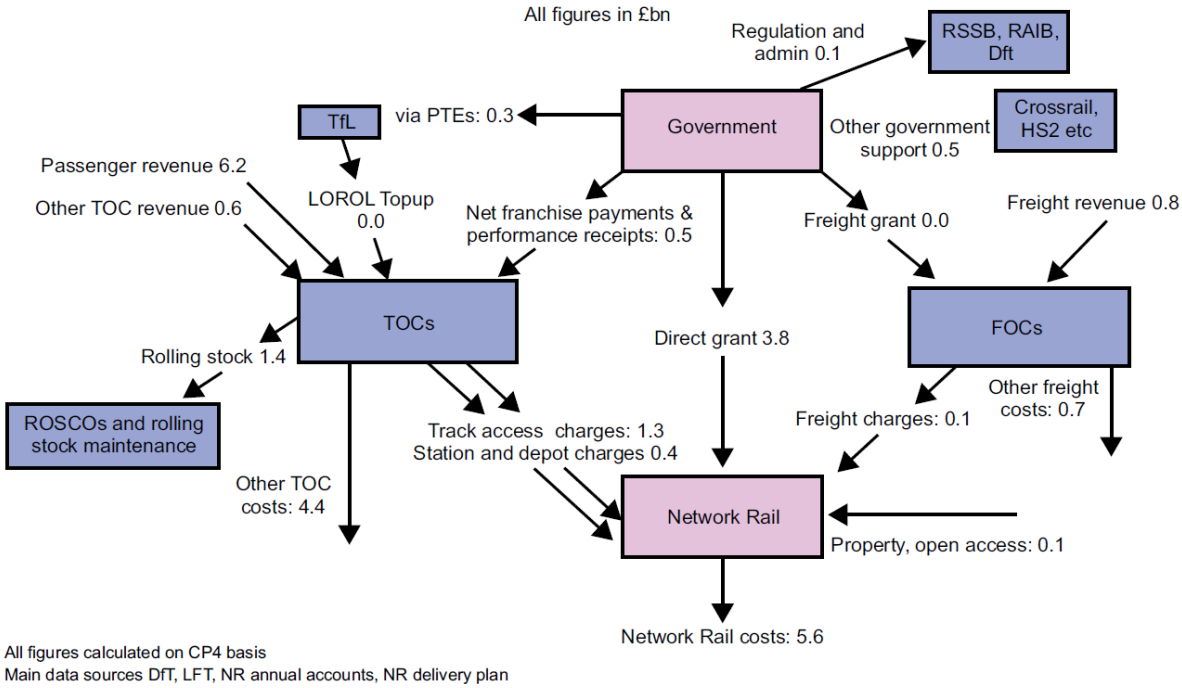
- **Figure 2 Existing structure of track access charges**[17, 18]

Network Rail's current track access charge structure, established at PR08, is a "two-part tariff" with fixed and variable elements. Variable charges based on estimates of marginal cost (differentiated by user type and type of vehicle) are paid by all users where applicable. The balance in required income is met from franchised train operators through a fixed charge. Fixed costs are allocated across these franchisees based on traffic metrics at a number of different levels of geographical disaggregation.

[17] From CEPA (2010) "High level review of track access charges and options for CP5: a report for ORR" http://www.rail-reg.gov.uk/upload/pdf/charges_review_cepa_report_june2010.pdf
[18] Source: CEPA / ORR

A.2.4 Revenue flows

Figure 3 below shows the money flows in the UK rail industry.



- **Figure 3 Rail industry money flows 2009/10 (GBP billion)**[19]

Figure 3 illustrates the important role of government. However, the cost structure of the industry is reflective of one that has been established for a long time, with legacy issues and sunk costs.

A.3 Overall system planning

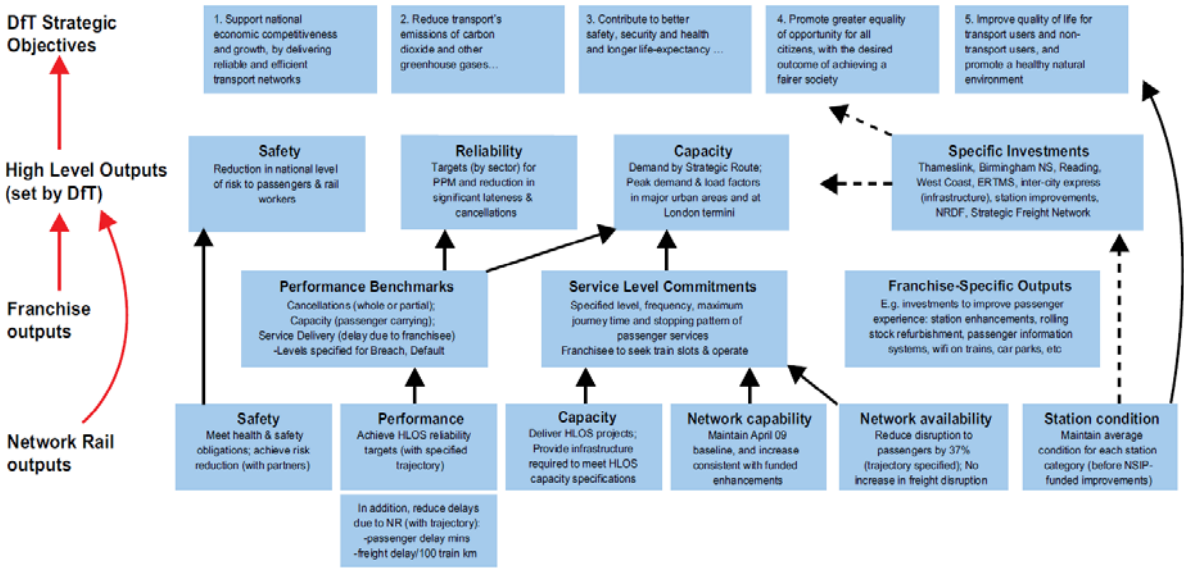
To a large extent the overall rail system has already been planned. Further strategic planning is only incremental in comparison to the extent of the network as a whole. The industry was initially developed from the 1830s by private companies in a relatively laissez faire manner resulting in much duplication and inefficiency in design. However as competition between each other and emerging transportation substitutes made rail unprofitable, eventual nationalisation under the Transport Act 1947 provided an opportunity for rationalisation and consolidation.

Today, the government is the main driver of the direction of the industry and system planning. Government funding is crucial for the viability of Network Rail and franchisees have outputs required in their franchise arrangements.

[19] Source: McNulty (2011)

The Railways Act 2005 established the High-Level Output Specification (HLOS) and Statement of Public Funds Available (SoFA) processes to shape the direction of the industry through the outputs to be subsidised and to set funding for the next five years.[20] HLOS defines the outputs to be funded and SoFA proposes the funds. This is then translated into Network Rail's regulatory settlement, set by ORR and the DFT HLOS1 set targets for the end of CP4 including safety, reliability, capacity, and major projects and other investments in support of DFT strategy and objectives. ORR needs to determine the targets for Network Rail to meet the HLOS, how much revenue is needed to deliver them efficiently and the implication for this on its regulated charges.

Figure 4 below shows the outputs as a hierarchy as found in the McNulty report.



- **Figure 4 Hierarchy of railway outputs (England and Wales)** [21]

The McNulty report explains that going forward, the next HLOS will be informed by "Planning Ahead" a series of cross-industry plans for the direction of the industry over the next 25 years, led by Network Rail, the Association of Train Operating Companies (ATOC) and the Rail Freight Operators' Association.[22] These will feed into Network Rail's Industry Strategic Business Plan and help to try to future-proof investment plans without needless over-specification.

[20] Slightly different processes exist in Scotland
[21] Source: McNulty (2011)
[22] See http://www.era.europa.eu/Core-Activities/Interoperability/Pages/TechnicalSpecifications.aspx. More information on this process and the information developed is provided in appendix 1 to this annex.

The DFT will also have influence through its franchising and role in supporting most major new projects. The plans for HS2, the second phase of high-speed rail in England for example are being led by government.

These processes are in turn influenced by the Route Utilisation Strategies (RUSs) developed by Network Rail to establish cross-industry plans for the medium to long-term. McNulty characterises this as "a form of 'predict and provide', with the RUSs setting out demand forecasts and the enhancements required to meet any resulting gaps."[23] These enhancements will be mainly covered under the SoFA.

This is supported by more minor investments driven more directly by the private sector such as with Chiltern Rail's Evergreen schemes or freight adaptations on lines to Southampton part-funded by British Associated Ports.

A.4 Shared assets

Rail capacity is shared between operators but not everywhere and not always to the same extent. Adaptations for heavy freight or fast commuter services affect all users but benefits are spread unequally. Consequently coordination and anticipation of future needs is important given the long lead time for investments to be realised.

To use the network, operators must have a track access contract with Network Rail approved by the ORR. Most access of these contracts last for five to ten years. Access granted under these contracts is governed by the Network code.[24] The network code includes:

- the translation of access rights into the construction of the timetable;
- changes to access rights following changes to the network;
- information flow requirements;
- process for establishing performance agreements between Network Rail and train operators;
- procedures for appeals to the ORR; and
- access dispute resolution rules.

When terms for access are unfair, access can be appealed to ORR who have "concurrent jurisdiction with the Office of Fair Trading to investigate potential breaches of the Competition Act 1998 in relation to the railways."[25]

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[23] See page 78 of McNulty report.
[24] See http://www.rail-reg.gov.uk/server/show/nav.241
[25] http://www.rail-reg.gov.uk/server/show/nav.95

ORR have developed model contracts with standard provisions for freight and for scheduled, franchised passenger services. They have also developed "track access options" which are contracts for access rights in the future. These allow an investor to secure access rights to take advantage of a proposed investment. Track access contracts however are not the only contract required as applications are required for other facilities including stations. These also must be on reasonable terms.

Access applicants must first negotiate terms with Network Rail. Network Rail then consults with stakeholders that might be affected by the new rights and deals with any arising issues with the applicant. Network Rail expects this process to take six weeks. If there is agreement, the contract can be approved by ORR under section 18 of the Railways Act 1993. If the applicant cannot get the desired access or terms, they can apply to the ORR to force Network Rail to allow access under section 17 of the Act. ORR approval can take between six and 12 weeks. They must make decisions on disputed applications within two months of receiving all relevant information.

Detailed further information on the access process is provided in ORR's guide to the regulatory framework.[26]

A.5 Pre-commitment and anticipatory investment

There are a number of ways of funding, procuring and delivering rail investments in GB. Large projects are usually driven by government (see previous sections) whereas smaller enhancements are negotiated directly with Network Rail through Principal Agreements. Some schemes are fully funded, managed and delivered by Network Rail, some are part-funded by interested stake holders, and others are developed by third parties and then sold to Network Rail.[27]

Track access options (introduced in the previous section) provide a concrete mechanism through which both an operator can secure future access to the network and an investor can receive greater confidence that they will have an asset that will generate benefits.[28] These agreements are made between train operators and facility owners (usually Network Rail). The most high profile case of use of these options is the Crossrail scheme in London.[29]

Track access options must be approved by the ORR. They will usually be allowed "where they are supported by focused and dedicated financial investment in a railway facility." This will be such that the option will be contingent on an investment at a specific location, facility or wider scheme

[26] ORR (2008) "Starting mainline rail operations: A guide to the regulatory framework" http://www.rail-reg.gov.uk/upload/pdf/387_cm.pdf
[27] Appendix 2 to this annex provides an overview of Project Evergreen, one of the key examples of stakeholder led investment in GB rail.
[28] http://www.rail-reg.gov.uk/upload/pdf/350.pdf
[29] http://www.rail-reg.gov.uk/server/show/ConWebDoc.9362

being completed. Track access option rights are on a use it or lose it basis. Therefore the "promoter" must satisfy themselves that once the option has been granted, it will be fully used. Conversely, buy-back mechanisms are also required in all options longer than 15 years, and can be exercised if a third party demonstrates additional benefit from a proposed alternative use.

Applications must take less than 18 weeks but can take longer, up to six months, when there are major objections.

A.6 Standardisation

The fragmented approach to system-wide planning in the industry is reflected in the management of technical and operational standards. The McNulty Report reported comments that the industry had too many standards, often overlapping, conflicting with each other and resulting in additional cost and delay.

The McNulty Report cites a number of industry bodies that seek to act and speak for the industry at a system-wide level. These include the Department for Transport, Network Rail, ORR, the RSSB, trade associations, individual operators and suppliers. McNulty reported that while each feels it is acting in the best interest of the industry, they feel progress is hampered by the other parties' pursuit of self-interest. Examples of the projects that have suffered because of the lack of a cohesive approach include next-generation signalling technology, regenerative braking technology and standardisation of rolling stock.

Standards for subsystems (infrastructure, energy, locomotives and passenger rolling stock, and telematic applications for passenger services) and components used on the railways are governed by the European Technical Standards for Interoperability. These standards are set by the European Railway Agency, an agency of the European Commission. Revisions of standards are made in coordination with other European standards bodies and relevant notified bodies. In its activities, the Agency co-operates with the railway representative organisations and national safety authorities, as well as with the European standardisation bodies and notified bodies.

Where the European standards are incomplete or do not apply, National Notified Technical Rules provide guidance. These are mainly included in the Railway Group Standards (RGS) applying to Network Rail. The RSSB manages the 171 RGSs and other industry standards, guidance material and codes.

Companies also use their own standards for design and procurement. McNulty notes that Network Rail has 1,250 company design standards and 122 guidance notes. Other more general European and national standards also apply to the industry. McNulty found evidence that derogations to some standards can take at least 15 months. This has clearly been a problem since it has limited the ability to move rolling stock around the country.

A.7 Investment delivery performance

McNulty cites recent examples of enhancement schemes with significant cost overruns and delays:

- West Coast Mainline modernisation was funded at GBP 3b in 1990s but eventually cost GBP 9b despite reduction of the specification from 140mph to 125mph;
- Thameslink programme funded in 2003 at GBP 2.7b but with forecast to be GBP 5.5b;
- GSM-R cab radio fitment, funded at GBP 117M in 2003, now forecast to be GBP 196M; and
- Halcrow estimated the average cost overrun from output definition to completion was 67 percent.

Network Rail has now refocused some their assessment efforts at the earlier scoping stages of projects to reflect these errors. However this reflects a risk of under-scoping where costs can ultimately be met through regulated fees or the DFT grant.

A.8 Summary

Clearly the reforms of the 1990s while meant to enhance transparency and efficiency have led to significant coordination and cooperation issues. The McNulty report has high-lighted several ways in which the process can be improved, including:

- longer-term planning horizons which will inform the five yearly regulatory and investment process (this is similar to the approach that has been adopted in the water industry in England & Wales with strategic direction statements providing the broader horizon); and
- ensuring that standards are appropriate, support efficient use of the system and do not create over-lapping and conflicting situations. This can also include stream-lining the bodies responsible for the sector.

Annex A.1 The twenty five year Rail Plan

A report, entitled 'Planning Ahead 2010: The long-term framework,' was published by a combination of the Rail Freight Operator's Network, the Association of Train Operating Companies (ATOC) and Network Rail.
(http://www.atoc.org/clientfiles/File/Planning%20Ahead%20(August%202010)%20(2).pdf)

In formulating this report, input was sought from the National Task Force, the Sustainable Rail Programme and the Technical Strategy Advisory Group. The 'Planning Ahead' report contributed to a report by Sir Roy McNulty, who went on to high-light the need to develop a strategy for the medium-term in his 'Rail Value for Money' study.
(http://www.rail-reg.gov.uk/server/show/ConWebDoc.10401)

The main issues to tackle include how to meet growing demand, how to increase the market share of rail for both passengers and freight, provide value for money and a better customer experience.

A list of aims by 2035 is given in this report. These are:

- Passenger satisfaction levels of 90%+;
- Double passenger capacity, reduce journey times and better connectivity;
- Improve freight product offering and increase market share;
- Relative to Europe, have high reliability and safety numbers;
- A financially sustainable railway system; and
- Reduced carbon dioxide emissions.

This led to a further advisory role to the UK Government and Scottish Ministers in developing their HLOS and details of this partnership's proposals were published in September 2011 in the Initial Industry Plan (IIP).
(http://www.atoc.org/clientfiles/File/Final%20IIP%20EW.pdf)

In the IIP, a number of policy issues are addressed. These include:

- Sustainability policy;
- Energy and Climate Change policy;
- High-speed Rail;
- Fares;
- Regulatory and franchising frameworks; and
- European legislation.

The IIP is intended as a starting point for discussions with the DfT and ORR on the priorities for CP5[30], but also goes beyond that in looking ahead at the future of rail over the coming twenty-five years. It does specifically address a railway system by the end of CP5, especially in terms of facilitating a financially sustainable model.

The IIP also gives indicative targets for outputs that they believe are feasible. These largely correspond with the aims listed in the first set of bullet points, but give values to achieve e.g. reducing industry CO2 emissions per passenger kilometre by 25%, and reduce the annual net cost of rail to the taxpayer to GBP 1b (down from GBP 3b).[31] In the HLOS, output targets are given, so this is a similarity between the two.

Forecasted figures for the end of CP5 and beyond are given within this IIP to aid the development of the HLOS in predicting how measures will contribute to their specific output targets. Analyses from the McNulty Report are utilised in adding to this study.

The DfT will publish the HLOS for Control Period 5 in summer 2012, with Network Rail responding before autumn 2013, when the ORR will give feedback. Network Rail's more detailed CP5 delivery plan will be published in early 2014.

[30] Control Period 5 will go from 2014-19
[31] P.7 IIP

Annex A.2 Project Evergreen

How does this fit in with the national rail system?

In 2004, a White Paper, 'The Future of Rail,' was published. A year later the responsibilities for the strategic and financial planning of the railways is passed on from the Strategic Rail Authority (SRA) to the Secretary of State for Transport. National policy, specifically PPS1 and PPG13 emphasise the need to promote development on public transport routes and provide an attractive and sustainable alternative to driving a car.

How does Chiltern Railways operate?

In 2002, the SRA granted a franchise to Chiltern Railways for a guaranteed minimum of 10yrs with the capability of a 20yr agreement contingent on delivering further investment. This stage involved carrying out a process called a 'Passenger Service Output Update (PSOU),' two of which have now been delivered. The major investment projects have been titled Project Evergreen and then a number to denote which investment this related to.

What were Project Evergreen 1 & 2?

Project Evergreen 1 started immediately after being granted the Franchise Agreement. This involved reinstating a double track between Princes Risborough and Aynho Junction.

In 2004, Chiltern Railways contracted to delivering Project Evergreen 2 – increasing line capacity between London and Princes Risborough and increasing the number of platforms at London Marylebone. This increased the minimum franchise term to 12yrs.

As part of the first PSOU, one noted improvement was redeveloping Aylesbury Station. Chiltern Railways contracted this and their minimum franchise agreement was increased by a further 6 months.

Some of the works remain under the control of Chiltern Railways, while others have been transferred to Network Rail.

What is Project Evergreen 3?

Chiltern Railways proposed this project on 1 August 2008, as the first stage of the second PSOU process. This PSOU process concluded in January 2010. Chiltern Railways entered into an Asset Protection Agreement and Asset Purchase Agreement with Network Rail, stipulating that Network Rail would purchase the completed works. BAM Nuttall was contracted by Chiltern Railways to conduct this project.

The proposal included:

- Improvements to existing line between Bicester and Oxford;

- Connect this line to the London to Birmingham main line;
- To build a new station at Water Eaton Parkway; and
- Improvements to existing structures e.g. around Oxford Station.

This will allow Chiltern Railways to run a service between Oxford and London twice an hour, with reduced journey times and new options. The train station will be more conveniently located to access the centre of Oxford.

The project is split into three phases, each of which has different funding and objectives. The key deliverables of this scheme are noted in Table 6.1 of the Order document:

Phase 1 New Bicester Chord line; track doubling Gavray Road Junction - Langford Junction, and Islip Junction – Peartree Junction; new line Woodstock Road Junction-Oxford station; rebuilding Bicester Town, Islip and Oxford stations; new station at Water Eaton Parkway; resignalling throughout; closing and replacing level crossings; mitigation works.

Phase 2A W12+ clearance for double track, Wolvercot Tunnel and elsewhere.

Phase 2B Double track Langford Junction-Islip junction and Peartree Junction- Woodstock Road junction; second platform at Islip station; new MoD connection and widening of A41 bridge for 3 tracks; mitigation works.

Phase 1 and 2A will cost a combined GBP 111M, while Phase 2B is projected to cost GBP 74M. This compares to Project Evergreen 2, which cost GBP 80M.

Chiltern Railways are fully funding Phase 1 as a commercial venture. Phase 2A is being funded by the Department for Transport, to help facilitate the East West Rail Link (Section 1.5). Phase 2B will only go ahead if the East West Rail Link is authorised.

Specifics of the Phase 1 agreement:

- Chiltern Railways take on the specification risk by funding the outline design and development work.
- Chiltern Railways also take on the costs and risks of delivery and will pay the contractor based on project deliverables.
- Network Rail will then pay Chiltern Railways at a pre-agreed rate when certain milestones are reached.
- Chiltern Railways and any successors (from 2022) will then pay Network Rail a facility charge for the next 30 years at an agreed rate with the ORR and take on any revenue risk.
- Any traffic associated with the users of the East West Rail Link will pay Network Rail a fee, but Chiltern Railways will receive no financial benefits from this.

- This means that the Franchise Agreement for Chiltern Railways is now valid for a 20yr period from 2002. And
- Also First Great Western Ltd has relinquished rights to operate passenger services between Oxford and Bicester and this was transferred to Chiltern Railways in May 2011. First Great Western stated in a letter of support that this would benefit the wider rail network.

The table below gives a summary of the expected net benefits for the entire Franchise Agreement duration and for its last full year in 2021 (Source: Chiltern Railways).

- **Table 3 Chiltern Railways Business Case**

Summary Business Case 18 December 2009		
	Total 2010-2021@ £m	**For Year 2021@ £m**
Income	157.3	21.6
Network Rail facility charge	- 116.5	-12.1
Incremental maintenance & renewals	- 26.3	-3.0
Incremental train operating costs	-7.6	-1.2
Station operations, marketing, staffing	-5.5	-0.8
3rd party agreements	-18.1	0
DfT payment for Phase 2A works	18.0	0
Total cash flow	**1.1**	**4.6**
Note: @ 2021 is the last full year of the Chiltern Railways Franchise Source: Chiltern Railways		

What is the East West Rail Link?

This is a project based on creating a 'knowledge arc' between Oxford and Cambridge, while improving access to Milton Keynes. The East West Rail Consortium is a partnership of local authorities and other agencies, including Oxfordshire County Council, has planned to re-open lines from Oxford and Bicester.

"Work is now proceeding on the EWR funding model, and on a detailed "Programme Entry" Business Case. It is expected that this will be formally submitted to the DfT in the autumn of 2010, Programme Entry secured in 2011 and DfT Rail High Level Output Statement [HLOS] identification secured in 2012. Conditional Funding approval is anticipated for 2013, followed by Invitations to Tender being issued and Full Approval secured in 2014 (i.e. the start of Network Rail CP5). This would enable construction to start in 2015, and services to commence in 2017." (http://www.chiltern-evergreen3.co.uk/uploads/Statement%20of%20Case%20amended%20final%20060810.pdf)

How have plans changed since the project proposal?

In January, following the apparent success of the project, ministers announced plans to now award fifteen year franchise contracts rather than ten year agreements.

The ORR announced in March 2011 that Network Rail had taken over responsibility for Project Evergreen 3 due to 'significant risks to timescales.' The start of new services had been delayed from May until September at the point of this announcement. This follows the hiring of an independent contractor, Halcrow, undertaking an evaluation of the project progress so far. The service was launched on 5th September 2011.

Appendix B GB Oil and Gas offshore pipelines

B.1 Introduction

Oil and gas have been extracted from the North Sea in earnest since the 1970s with the discovery of the large Forties and Brent oilfields. The location of the fields in the North Sea (Forties is 110 miles from Aberdeen; Brent is 116 miles from Lerwick) meant that significant pipeline infrastructure is required to transport the oil and gas to land.

Oil and gas production in the North Sea peaked in 1999, since then output has been falling at an average of 5% per year. As the fields mature the offshore infrastructure faces a number of challenges. Firstly, the maintenance costs of the infrastructure increase and faults are more likely- as is reflected in the recent leak from Shell's Gannet Alpha pipeline. Secondly, as the large fields reach the end of their useful life, the infrastructure must adapt to the challenges of extracting oil from the smaller more marginal fields, often requiring larger contractors to share infrastructure with smaller producers.

Whilst the industry output is declining in the UK, it still is responsible for 350,000 UK jobs and almost GBP 8b a year in tax revenues and maintaining this industry requires a suitable tax regime and incentives to invest in the development of new fields, which has already been sparked by increasing oil prices.

This case study analyses current issues in the UK oil and gas sector, with a focus on the surrounding coordinated development in the industry, which has proven of key importance as the industry matures. The remainder of the annex is split into five sections:

- Industry structure and regulatory regime;
- Third party access to pipeline infrastructure (including the possibility of common carrier arrangements and issues of standardisation of contracts);
- Investments for reaching new, smaller fields;
- The tax regime; and
- Depreciation and decommissioning of existing assets.

These are discussed in greater detail below.

B.1.1 Industry structure and regulatory regime

Actors

BP is the largest oil producer in the UK, with 23 fields, and other large oil producers in the UK include Nexen, Shell, and Total. As UK oil fields mature, the industry now focuses on increasing the productivity of existing fields and developing smaller fields that were previously considered non-commercial. Major oil companies, especially BP and Shell, have begun to sell their UK fields

to focus on international opportunities, and this has left the market open for smaller companies. For example in 2003, Apache purchased the Forties field from BP for USD 630 million, and other smaller operators, such as Talisman and Nexen have similarly acquired significant production assets. In 2009, five of the top ten producers were smaller operators. In June 2010, five smaller operators- Premier, Encore, Wintershall, Nautical Petroleum and Agora Oil- discovered the 300m barrel Catcher field, a find on a scale that was not expected to be present in the North Sea anymore. Finds of this size, spurred by high oil prices, have led to a 'renaissance' in the North Sea.

Transmission infrastructure[32]

There is an extensive network of pipelines to transport extracted oil:

- BP operates two 110-mile pipelines, one connecting the Forties system to Cruden Bay, on the mainland, the other connecting the Ninnian system to the Sullom Voe oil terminal on Shetland Island.
- Britoil Plc operates a 150-mile pipeline linking the Bruce and Forties fields to Cruden Bay;
- Talisman operates a 130-mile pipeline connecting the Piper system with Flotta on the Orkney Islands; and
- Shell and Esso jointly operate a 93-mile connection between the Cormorant oil field and Sullom Voe;

In addition there are small pipelines that connect each North Sea oil platform to these major pipes.

There are also four main pipelines that carry natural gas from offshore platforms to onshore landing terminals:

- The Shearwater-Elgin Line, operated by Shell, transports gas to the landing terminal at Bacton, England.
- The 200-mile Scottish Area Gas Evacuation, operated by ExxonMobil, transports associated natural gas from UK continental shelf (UKCS) fields to St. Fergus, Scotland.
- The 250-mile, Central Area Transmission System, operated by BP, links fields in the Central North Sea to Teesside.
- Shell operates the 283-mile Far North Liquids and Gas System linking the Brent oil system with St. Fergus.

[32] Adapted from US Energy Information Administration's 'Country Analysis Briefs' accessed at: http://www.eia.gov/emeu/cabs/United_Kingdom/pdf.pdf

Regulatory regime

In the UK, DECC is responsible for licensing, exploration and regulation of oil and gas developments on the UKCS. In terms of coordination and development, the regulatory role is relatively limited, and the producers determine the development of the industry. Despite virtually all the oil and gas being in Scottish waters, oil is a reserved matter and is handled by the UK government. DECC is also responsible for the environmental issues surrounding the industry, and the Health and Safety Executive must approve every well before it is drilled. In addition, any pipe within 12 nautical miles of the UK coast requires a lease or license from TCE, who must also approve any pipeline. The lease varies with the length and diameter of the pipe; TCE must also be informed of any pipeline that is laid anywhere on the UKCS.

Offshore pipelines are covered by the 1998 Petroleum Act, which states that any work executed for the construction of a pipeline in, under or over territorial seas and other controlled waters and the use of any such pipeline is subject to the written authorisation of the Secretary of State. Authorisation will only be provided to a 'body corporate'[33] and a for a Pipeline Works Authorisation to be granted other requirement such as the establishment of the route of the pipeline and the steps to be taken to avoid the interference with fishing and other activities must be met.

B.1.2 Third party access

Over recent years the focus has been less on building pipelines, rather for the shared use of existing pipelines. The smaller accumulations that are currently being found in the North Sea cannot sustain their own pipelines and infrastructure, and must be able to use existing pipelines through Third Party Access (TPA) arrangements: the availability and accessibility of this infrastructure ultimately determines the future exploration in the North Sea.

In 1996, a voluntary code of practice was set up providing guidelines and procedures to enable interested parties to become users of the available offshore infrastructure. This was updated in 2004 and 2009 and applies to all infrastructure in the UKCS. The main principles governing the Code are[34]:

- Parties provide meaningful information to each other during commercial negotiations;
- Parties support negotiated access in a timely manner;
- Parties undertake to ultimately settle disputes with a referral to the Secretary of State;
- Parties resolve conflicts of interest;

[33] A "body corporate" is one which has perpetual succession and a legal personality distinct from that of its members. In the United Kingdom a body corporate includes companies with limited or unlimited liability, companies limited by guarantee, charter companies and bodies created by statute.
[34] 'Code of Practice on Access to Upstream Oil and Gas Infrastructure on the UK Continental Shelf', January 2009, DECC and Oil and Gas UK

- Infrastructure owners provide transparent and non-discriminatory access;
- Infrastructure owners provide tariffs and terms for unbundled services, where practicable;
- Parties seek to agree reasonable terms, with risks reflected by rewards; and
- Parties publish key, agreed commercial provisions.

The code is supported by the PILOT industry-Government taskforce, which took over from the Oil and Gas Industry Taskforce in 2000. PILOT aims to be a forum for co-operation between industry and government. In particular, it does this in order to achieve full recovery of our hydrocarbon reserves, enhancing the level of activity in the UKCS, lifting commercial barriers to the entry of small and medium sized companies to exploit the resources available. Appendix 1 to this annex provides some further information on PILOT and DECC's stated views on its achievements to date.

However, in 2009, the Energy and Climate Change Committee's 'UK offshore oil and gas' report high-lighted that the code and other supports were not working. The Oil Gas Independents' Association high-lighted that the failure of the code was restricting the ability of its members to operate and threatened to push all the returns to the infrastructure provider rather than the producer, who takes all the risk. A particular challenge was that companies within a dispute were unwilling to take the other company to the Secretary of State, for fear of upsetting them. Oil and Gas UK, which maintains the code, concedes that there are problems and acknowledges that the access to infrastructure element of the code has not been successful.

The Government's response to Commission's 2009 report was to concede that there was a problem with the existing code, but argued that primarily this was exacerbated by the changes in the industry: for infrastructure systems with a number of TPA arrangements, there were standardized contracts already in place (as is recommended by The Code) However, for infrastructure systems with few or no existing third parties, it can take time for terms and conditions to be formulated for a new user. This is especially problematic if the infrastructure is aging or requires some form of additional support or adaptations from the service provider- for example, for carrying heavier oils.

Options for enforcing closer cooperation have been considered, in particular through a 'common carrier' system. In the boom following increasing oil prices in the last year, smaller producers have proven increasingly in support of such a step.[35] However, at the time of the Energy and Climate Change Committee's report, the then Secretary of State would not support this, nor would Oil and Gas UK, who believe that such a step would be very complicated and expensive. The 2009 Commission concluded that the government should have a greater role in strengthening the current system.

[35] 'Tide turns on search for oil in North Sea' (Oct 2010), Financial Times, accessed at http://www.ft.com/cms/s/0/7f538c9c-cf03-11df-9be2-00144feab49a.html#ixzz1VrZicKn3

The current coalition government have been very critical of previous TPA arrangements, suggesting that the existing legislation was 'piecemeal' and 'inconsistent'[36] and it aims to strengthen these in the Energy Bill that is currently passing through Parliament.

B.1.3 Investments for reaching smaller fields

Most of the significant remaining areas for prospecting in the UKCS are in the area to the West of Shetland, roughly 100km from the coast. These fields are estimated to hold between 2-4b barrels of oil and gas, but unlike the fields in the North Sea proper, these will for the most part require entirely new infrastructure to function. The area is 400km from the nearest gas terminal, and would require a new pipeline to be built to connect it to the mainland. In addition, extreme marine and weather conditions make development costly and dangerous.

Common carrier arrangements have again been considered for new developments. These were proposed for building pipelines in the North Sea previously, but were never undertaken because the banks were not prepared to finance a pipeline unless large throughput from a very big field was guaranteed.[37] Some form of subsidy, tax break or coordination is thought to be required from the government for the West of Shetland fields to be commercially viable in the long term. Oil and gas consultancy Hannon Westwood estimate that funding of as much as USD 8-18b could be required from the government to ensure long-term supply for the UK.[38]

Neither the producers nor the government are enthusiastic about active government involvement in this area: the Oil and Gas representative who gave evidence to the Energy and Climate Change commission was in favour of tax incentives for the industry; the then Energy Minister was concerned that any government intervention- whether through funding or regulation- would deter the major producers from involvement in the sector.[39] The preferred option was for the government to act as a facilitator for the companies making agreements and common arrangements. The Commission Report accepts this position but suggests that if progress on the West of Shetland development does not occur at the agreed timescale, the government should be prepared to take on a more active, regulatory, role.

Recent experiences high-light how difficult this may be. From 2006 onwards, a joint government-industry taskforce developed four commercially viable options for 'multi-field' gas gathering hubs, in an attempt to develop the fields as effectively as possible. Cooperation was planned between a

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[36] Louise Smith, (May 2011) 'Offshore oil and gas industry: Library of House of Commons Standard Note'
[37] Evidence of Professor Kemp, 19 March 2009, to the Energy and Climate Change Committee, http://www.publications.parliament.uk/pa/cm200809/cmselect/cmenergy/341/9031904.htm
[38] 'North Sea: Opportunities West of Shetland', (March 2011), Financial Times accessed at http://www.ft.com/cms/s/0/01519612-50fa-11e0-8931-00144feab49a.html#axzz1VrY4VRwX
[3939] Energy and Climate Change Commission Report (2009), p40-41

number of producer firms- Total, Chevron, BP, ExxonMobil, DONG Energy- and was considered a significant development for coordination in the market.

This taskforce aimed to 'identify whether there is an economic collective technical solution to the development of the resource base to the West of Shetland with a potential development horizon within the next five years compatible with project timing ranges and system export ullage' and 'to identify what commercial approach might make development attractive to contributing field owners'. It also considered TPA possibilities. The gas hub concepts developed in the first phase of the project were either onshore or offshore, with offshore hubs either in shallow or deep water, and with one deep water option including oil as well as gas.

Despite the clear cooperation in the first phase of the task force project, it has failed to agree a solution, and cooperation appears to have halted since 2008. Companies such as Total favoured a low-cost development, whilst the government favoured a large piece of infrastructure, such as a floating deepwater offshore platform, which could cost as much as GBP 500M.[40] In 2010, Total and Dong announced the development of the Laggan and Tormore fields, but discussion of further Taskforce cooperation appears to be limited.

B.1.4 Tax regime

The profits arising from oil and gas fall into two fiscal regimes:

- Petroleum revenue tax- this is a field based tax, and only applies to fields developed before 1993; and
- Ring-fenced corporation tax, which incorporates supplementary charge. Corporation tax on upstream oil and gas is set at 30% and a supplementary charge of 32% is set on adjusted ring fenced profits (this was increased from 20% in 2011, discussed in more detail below).

UK oil and gas are estimated to have brought in GBP 248b in tax revenues over the last four decades. As is to be expected, this tax rate- currently 62% marginal tax on new fields- is not popular with producers. Oil & Gas UK gave evidence to the Energy and Climate Change Committee that 'material improvements in the current tax regime are now required to stimulate additional capital investment', and BP noted that while the current regime was relatively fair in global terms, it had not adapted to the requirements of the mature basin, and was complex and unpredictable.

In 2009 the government introduced a 'Field Allowance' which will allow new fields with a fixed allowance that is offset against the supplementary charge that companies would pay. Once the

[40] 'Storm clouds gather over the West of Shetlands, Britain's last gas frontier' The Times, June 2008, http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article4227674.ece

allowance is used up (depending on the amount of oil and gas produced and the oil and gas prices) then the company pays the standard North Sea tax rate. The Field Allowance is applied to small fields, ultra heavy oil fields and ultra high temperature/high pressure fields. This received mixed reactions from the industry, with Oil & Gas UK suggesting it was a 'step in the right direction' but BP suggesting it would further complicate the tax regime.

Overall, though this and some other small changes made in 2009 were welcomed by the industry and the Energy and Climate Change Commission, it was not felt by either party that the government were doing enough to support the North Sea oil industry.

In the 2011 Budget, the new coalition government announced that it would increase the taxation on the oil and gas production industry to fund a cut in fuel duty. This would stabilise prices allowing fuel duty to increase by inflation only when oil prices were high, arguing that when oil prices are high, the companies are more profitable and thus should pay more. When oil prices fall again below a trigger price of a proposed USD 75 a barrel, the supplementary charge would return to 20%.[41] This change was very unpopular with producers, and it was reported that Centrica, Valiant Petroleum, Statoil, were reviewing their investments, with an expected fall in investment from GBP 33b to GBP 23b over the next ten years, with 25 projects unlikely to go ahead, and the lives of 20 producing fields to be shortened by at least 5 years.

B.2 Depreciation and decommissioning of existing assets

A prominent issue in the North Sea currently is the decommissioning of the existing assets. This work is expected to continue over the next 20 years, and is estimated to cost GBP 23b. The industry aims to keep the infrastructure running for as long as possible, for accessing marginal fields (as discussed above) and also to support carbon storage in used reservoirs. This is another issue where the industry is dissatisfied with the tax system as money set aside for decommissioning is taxed, in contrast to the regime for decommissioning liabilities in the nuclear industry.

B.3 Summary

While the oil and gas industry in the North Sea was a good example of how shared assets can be developed in a coordinated and cooperative manner, this seems to have been driven by the fact that significant players existed with major fields. Now that the focus is on smaller fields where the economics are much more affected by the infrastructure provided, similar coordination and cooperation problems to those for offshore electricity are being encountered.

Solutions to this are being developed – both by private operators and also as part of a broader government industry framework. Whether the government supported schemes will deliver the

[41] Louise Smith, (May 2011) 'Offshore oil and gas industry: Library of House of Commons Standard Note'

coordination that is needed is not clear. However, it may provide the initial starting point from which private cooperation develops.

Annex B.1 The PILOT Task Force

DECC's stated views on the achievements

- Attracting new players and global investment – a diverse range of new players entered the basin, which has led to the development of more small fields and technology. A range of new companies and operators have entered the market.
- Fallow initiative – this has stimulated activity by placing still prospective acreage into the hands of companies that want to develop it.
- Access to infrastructure – companies are able to negotiate with pipeline owners, etc, for access. This has helped enable subsea tiebacks to infrastructure hubs, although there are still ongoing challenges in this area.
- Stewardship – initiative to critically analyse the potential of each producing asset.
- Technology development – working to foster innovation and facilitating the development and implementation of new technologies. This led to establishment of the Industry Technology Facilitator.
- Skills – the industry workforce has increased by 100% throughout the life of PILOT, and oil and gas academy OPITO was established following work in PILOT.
- Exports – there has been a higher level of exports from the industry than anticipated and Subsea industry renowned across the world.
- Investment – levels of investment in the basin exceeded expectations, including rising capital investment in the current economic climate.

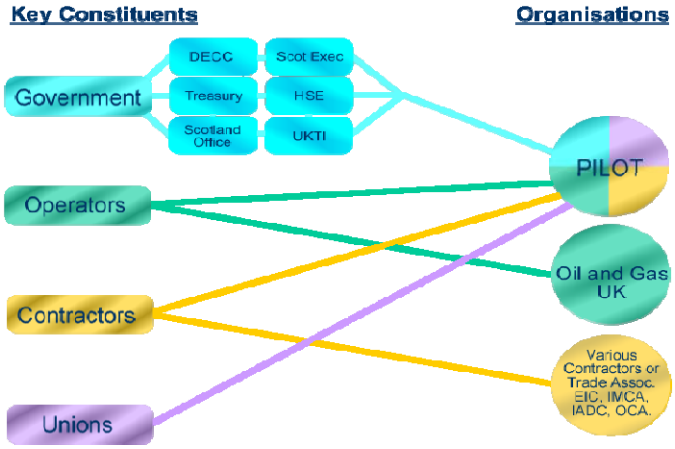
Future Work areas for PILOT

A PILOT summit was held in October 2010, this was a 'town hall' type meeting with cross industry representation to consider its future work areas and the following were identified and have been adopted as PILOT workgroups:

- Infrastructure
- Improving Recovery
- Access to Capital
- Technology

PILOT structure

The original structure of PILOT is given in the figure below. HSE and UKTI no longer sit on PILOT.



- **Figure 5 The original PILOT structure**

Appendix C Onshore transmission

C.1 Introduction

There is much that offshore transmission can learn from onshore transmission – although the wholesale extension of the onshore regime offshore should be approached carefully. This annex provides a series of shorter case studies that consider specific aspects of different onshore regimes that help illustrate issues for the development of offshore regimes.

C.2 Ireland – Group Processing Approach

C.2.1 Introduction

In December 2004, Ireland adopted the Group Processing Approach for all renewable generators wishing to connect to the transmission or distribution systems. This includes the connection of any offshore generation developments.

This case study examines the Group Processing Approach in Ireland, with a focus in the following areas:

- industry structure and regulatory regime;
- overall system planning;
- connection process;
- sharing of assets; and
- pre-commitment and anticipatory investment.

C.2.2 Industry Structure and Regulatory Regime[42,43]

Transmission Infrastructure

The transmission system comprises of approximately 6,500km of high voltage lines at 110kV, 220kV and 400kV. Power is transmitted down to the medium and low voltage distribution system where the majority of customers are connected. However there are also about 18 very large customers directly connected to transmission grid.

Regulatory Regime

The Irish Electricity market and the monopoly of transmission and distribution systems are regulated by the Commission for Energy Regulation (CER).

EirGrid is the independent state-owned body licensed by CER to act as the Transmission System Operator (TSO). They are responsible for the operation, maintenance and development of the Irish transmission network. However the ownership of the transmission assets is a separate licensing

[42] EirGrid website: http://www.eirgrid.com/transmission/
[43] CER Website: http://www.cer.ie/en/electricity-overview.aspx

activity and therefore EirGrid do not own the transmission assets that they operate. Instead ESB networks are licensed by CER to act as the TAO[44]. The TAO is responsible for maintaining the transmission network and for carrying out the construction work in accordance with the TSO's Transmission Development Plans. An infrastructure agreement, approved by CER, governs the ongoing relationship between the TSO and TAO.

The revenues and tariffs associated with the transmission system are also regulated by CER who implements price reviews every five years with annual refinements. The transmission tariffs include the Transmission Network Use of System tariffs (TNUoS) which is charged to generators and users connected to the network. The TNUoS charges to generators are based on the generator capacity and the location, whereby the closer the generator to the demand the cheaper the tariff[45].

In December 2004, the Group Processing Approach was adopted in for all renewable generation wishing to connect to the transmission of distribution systems (including any offshore generation developments). Under this approach, all applications that are deemed to be completed by a set date are processed as a batch. Each "batch" process is known as a Gate and there have been three successive gates to date. All applications in a batch are divided into groups and further sub-groups by the TSO and DSO depending on factors such as the geographic locations and potential level of interconnectivity.

This approach was adopted by the system operators with the aim to[46]:

- Increase the speed at which connection applications can be processed;
- Reduce conflict caused by interaction of two or more generator applications;
- Minimise the infrastructure required for connection;
- Allow for development of a more optimal network;
- High-light at an early stage areas that may be subject to congestion; and
- Optimise the use of resources.

[44] Note that ESB is also the distribution system operator (DSO)
[45]"Industrial Development Potential of Offshore Wind in Ireland", by Garrad Hassan on behalf of SEAI: http://www.seai.ie/Renewables/Ocean_Energy/Ocean_Energy_Information_Research/Ocean_Energy_Publications/Offshore_Wind_Study.pdf
[46]CER Website - Group Connection Processing: http://www.cer.ie/en/renewables-connecting-to-the-network.aspx?article=68c8fc68-4eab-4276-a7b8-4aa5113064f1

C.2.3 Overall system Planning[47]

Grid 25 is the strategy set out by EirGrid to develop Ireland's Electricity Grid for a "sustainable and competitive future". The strategy represents EUR 4 billion worth of investments between now and the year 2025. Grid 25 outlines the need for major reinforcements to the existing transmission system network. It is expected that by 2025 the capacity of the transmission system will need to have doubled to accommodate the increasing number of renewable generation and a 150% increase in electricity demand. The estimated grid developments are as follows:

Approximately 1,150km (20% increase on existing) of new high voltage circuit (above 220kV) and further circuits for generation connections; and

- Approximately 2,300km of existing 220kV and 110kV transmission network to be upgraded

At present the East-West interconnector (EWIC) project will provide a 500MW link to the UK by the third quarter in 2012. Grid 25 expected a further interconnection to be built by 2025 to the UK or France. This will strengthen the interconnectivity between Ireland and Europe and will facilitate participation in the European Energy Markets.

In addition to the onshore grid reinforcements, Ireland also has very strong views on the future development of offshore grids. In June 2011 EirGrid released the Executive Summary of the Offshore Grid Connection Study (the study is to be released shortly). According to the study the overall offshore grid design should be[48]:

- Meshed or interlinked and not a series of single connections from generators to the onshore network.
- Developed incrementally.
- Symbiotic with the onshore network and in line with GRID25 strategy.
- Developed making use of "smart" devices to enhance network flexibility
- Both an AC and DC offshore cable network interlinked are considered. However according to the "DRAFT Offshore Renewable Energy Development Plan (Nov 2010)"[49], AC technology will be preferred rather than DC because of short distances involved. Overall modular electrical design that will permit changes from AC to DC and vice versa will be investigated.

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[47] "Grid 25", EirGrid: http://www.eirgrid.com/media/Grid%2025.pdf
[48] DRAFT Offshore Renewable Energy Development Plan: http://www.dcenr.gov.ie/NR/rdonlyres/2990B205-534E-486E-8586-346A6770D4B6/0/Draft_13_OREDPWebversion.pdf
[49] Offshore Grid Study by EirGrid: http://www.eirgrid.com/media/EirGrid%20Offshore%20Grid%20Study.pdf

C.2.4 Connection Process[46, 50, 51, 52,53]

As of December 2004 renewable developments with a Maximum Export Capacity (MEC) above 0.5MW must seek connection through the group process application method unless the applicant can demonstrate that speeding up the process of the application is in the public's interest.

Under this approach, all applications that are deemed to be completed by a set date are processed as a batch. Each "batch" process is known as a Gate and there have been three successive gates to date. All applications in a batch are divided into groups and further sub-groups by the TSO and DSO depending on factors such as the geographic locations and potential level of interconnectivity.

The TSO/DSO carries out an assessment to determine the requirements of the each group/sub-group and the impact of the systems on the network. On completion of the assessment, the relevant TSO/DNO presents the applicants with the chosen option and the connection offer for each of the individual generators. Only one option for connection will be provided and this will be based on the Lease Cost connection method[54] with the assumption that all generators in the sub-group will connect. The Least Cost principle may take into account the wider development of the network and any future connections to the network. Where it is technically justified, the system operator can also choose to nominate whether the generator connects to the transmission or distribution level. The customer and subgroup may request an alternative connection method.

Connection Schedule[52]

The individual connections will each be provided with a schedule of firm capacity and therefore the generators within each sub-group may not have the same dates for firm access to the transmission system. The schedule of firm capacity is based on the Incremental Transmission Capacity (ITC) Programme, whereby any available capacity will be allocated to the generator with the earliest application dates (i.e. on a first-come-first-service basis). If the generation exceeds the available capacity, then the generation offer is still made but with a reduced firm capacity until further capacity becomes available.

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[50] "System Operator GPA Pricing Principles", CER: http://www.cer.ie/en/electricity-distribution-network-current-consultations.aspx?article=b6fd1d87-1355-4927-8ca5-0d979872055e

[51] " Group Processing Approach for Renewable Generator Connection Applications and Pricing Rules" CER: http://www.cer.ie/en/renewables-decision-documents.aspx?article=12d5c404-7388-4683-b519-8136e66d8322

[52] "Criteria for Gate 3 Renewable Generator Offers & Related matters", CER: http://www.eirgrid.com/media/CER_08_260.pdf

[53] "Joint TSO and DSO Group Processing Approach -Charging and Rebating Principles cer10085", CER http://www.cer.ie/en/electricity-distribution-network-current-consultations.aspx?article=b6fd1d87-1355-4927-8ca5-0d979872055e

[54] Note that this was previously termed the Least Cost Technically Acceptable (LTCA) method but it was deemed misleading due to the difference in the transmission and distribution boundaries which affect what connection method may or may not be termed as technically acceptable.

Alongside the connection offer, the TSO may also issue an estimate of the likely constraints on the generator's outputs with timelines from the commissioning of the generator until the necessary transmission reinforcements can be carried out.

Gate 3 Application Criteria

The following must be submitted as part of the application before the development can be included in the Gate 3 process:

- Payment of the first EUR 7,000 of the application fee;
- Generator grid co-ordinates;
- Maximum export capacity;
- Internal network layout and major equipment location;
- Preferred connection date;
- Technical data. Any consequences arising from deviation of the technical data provided in the actual generation will be borne by the developer; and
- Signed statement from the applicant (witnessed by a solicitor) that any land consents required have been obtained from the necessary land owner.[55]

In the Gate 3 process and subsequent Gate processes CER has decided that it is no longer a criteria to obtain planning permission as part of the Gate application process. This is because the planning consents expire after five years and this can result in timing issues.

If the application is considered to be complete before the specified deadline then the generation will be considered in the Gate 3 process. The TSO/DSO will assess the nodes at which each generation will be connected. This is based on the size (i.e. connection voltage) and location of the generator. The generator will be divided into sub-groups depending on the assigned nodes.

Unlike the previous gate process, connection method meetings were held prior to the connection offer in the Gate 3 process. This was to allow more flexibility before the connection offer was made and prevent a large number of modification and change requests after the connection offer is made. The aim of these meetings is for the system operators to explain the chosen connection approach and for queries and discussions among the system operators and developers.

The decision process for Gate 3 is provided in Figure 5[53] below.

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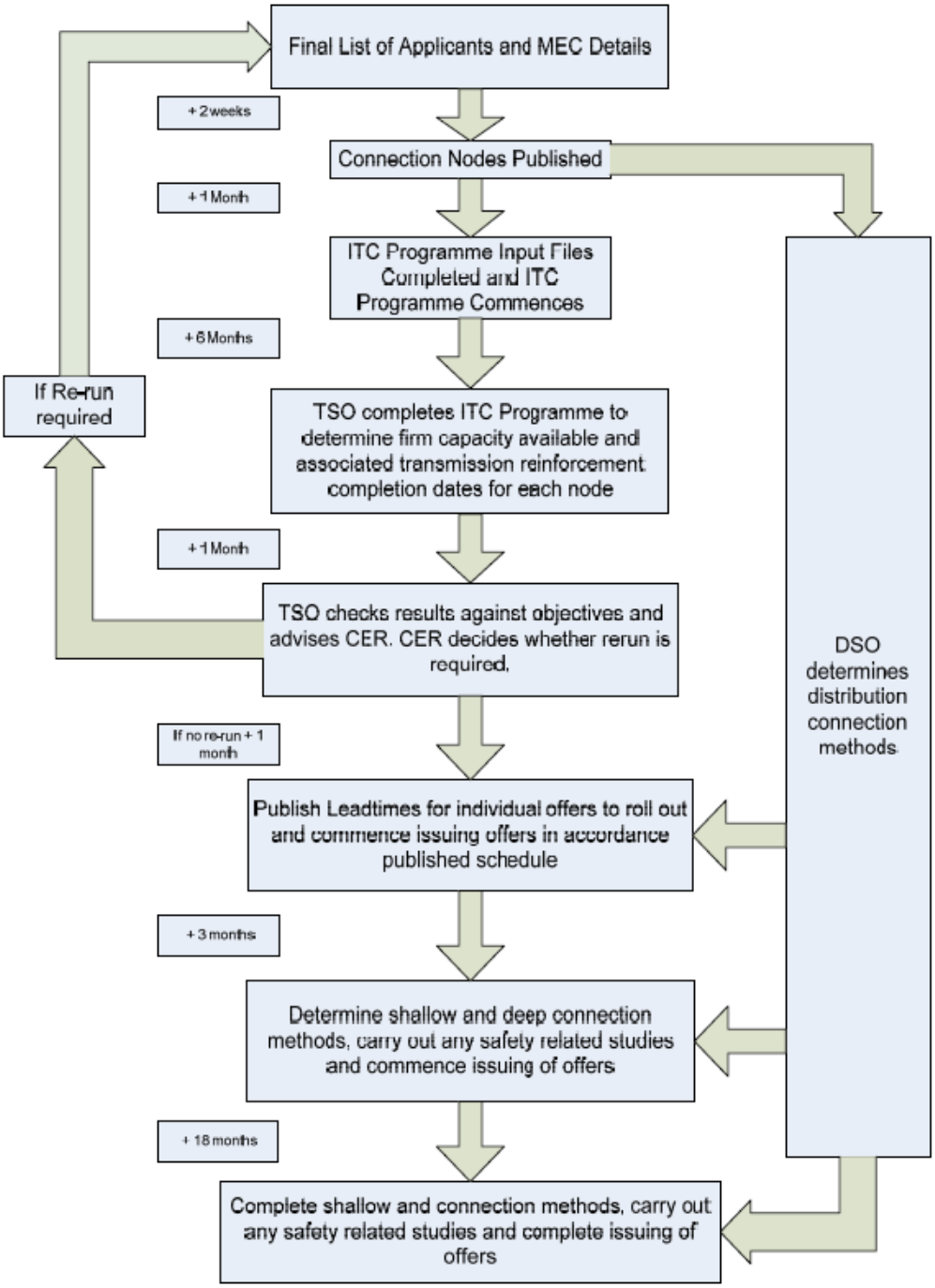
[55] This was originally not a requirement for transmission connected generators but in order to align the two system operators, CER made the decision that any land that needs to be acquired must be done so and proof provided to the system operators in a confirmation statement. This was issued as part of the direction in December 2008 and all confirmation statements had to be provided within a few weeks of the direction or be excluded for the Gate 3 process.



- **Figure 6 Gate 3 decision process**

C.2.5 Sharing of Assets[53]

The assets associated with connection to the transmission or distribution system will be paid for by the generator. The connection charge for transmission applicants will only include the cost of the "shallow"[56] transmission assets. However distribution connected generators will be required to pay for both the "shallow" and "deep" connection assets. The connection charges will take into account the cost of construction, installation and maintenance of the connection assets and, in some cases, refunding parties who have paid for existing assets.

Unless an alternative method of connection is requested, the subgroup will pay for the least cost connection method selected at the time that the offer is issued. If there are increases to the cost, due to a change in systems standards between the offer issue and the construction of the assets, this will be borne by the TNUoS[57] customer.

The least cost solution will include the following:

- Capital cost of equipment required for the connection;
- Cable works. Note that this will be carried out by the customer and therefore the System Operator does not claim these costs;
- Cost of the customer's transformer;
- Civil costs.

In addition to the costs mentioned above, the developer might incur some "pass through costs" which are costs that cannot be controlled directly by the system operator or recovered by the TAO. This cost may arise from changes to the cost of consents, timing of connection, project management fees for contestable connections and the method of connection. The TSO's offer letter will include an estimate of these costs.

The generators connected to the network will also pay and annual operation and maintenance (O&M) charge for the shallow assets. For transmission connected developments, this is known as the "on-going service charges".

Existing Assets

Charges on existing assets required for connection and rebates to existing customers (or TNUoS) will be reduced accordingly as to avoid non-optimum system development.

If the developer is required to connect to an existing substation, they will pay for the cost of the connection assets (e.g. bays, protection) and a portion of the Substation common costs determined

[56] This can partially include some deep works depending on the availability of appropriate transmission infrastructure
[57] 20% Generation, 80% Load

on the basis of the number of bays or per MW. They will also pay for their share of the any station works that is required.

Dedicated Connection Assets[50,51]

Each applicant will pay the full cost of its own dedicated connection to the shared transmission network. However in the case where the dedicated connection asset has been oversized, the applicants of the sub-groups do not pay for any costs incurred on top of the original costs derived from the Least Cost method.

Shared Connection Assets

The cost of the shared network will be split between the generators, on the basis of the MEC of each generator. Note that the annual ongoing service charges are also determined using the MEC.

The connection cost is calculated using the following formula[51]:

Transmission Connections: $P_T * X * (Z/W)$

Distribution Connections: $[(P_T * X) * (Z/W)] + [(P_D * Y) * (Z/V)]$

Where:

X = Total cost (LCC/LCTA for the subgroup) of providing the associated transmission works of the Shared Network including remote end station allocated charges

Y = Total cost of providing the associated distribution works of the Shared Network

Z = MEC (in MW) of the specific generating plant

W = Total MEC (in MW) of the Generator Applications in that Subgroup

V = Total MEC (in MW) of the DSO Generator Applications in that Subgroup*

P_T = Transmission Probability Factor = 1 for all Gates to date

P_D = Distribution Probability Factor = 1 for all Gates to date

The transmission probability factor (PT) is determined by CER and can act as a mechanism to minimise any potential liabilities for the System Operator in the event that a committed project fails to proceed and to increase the chances of recovering all of the actual cost. For all Gate processes so far (1, 2 and 3) a factor of 1 was used, thus assuming that all the applicants will complete their projects and pay their full share of the transmission connection costs. [51, 58]

[58]"Group Processing Approach for Renewable Generator Connection Applications–Connection and Pricing Provisions", CER: http://www.cer.ie/GetAttachment.aspx?id=81168eea-8880-4ce6-80b1-db026235ec9c

At present, the connection payments are distributed as follows[59]:

- The lesser of 10% or the lesser of EUR 10,000 per MW on Offer Acceptance (First stage payment)
- 50% at the Preconstruction Stage
- Balance at Final Energisation

The first stage payment can be done in two instalments; the first on the acceptance of the connection offer and, for transmission connected applicants, the second instalment is required 12 months before the scheduled Consent Issue Date[60].

CER are currently considering a joint proposal from EirGrid and ESB networks to align the distribution and transmission payment schedule. The proposed payment schedule for all renewable and conventional generators is as follows[59]:

- First stage payment on offer acceptance
- 55% at the Preconstruction Stage
- 25% one calendar month before energisation
- Balance one calendar month after final energisation.

Contestability

In most cases, the system operator will be responsible for the connection details, consent and wayleaves, materials procurements and construction of the connection. Note that the on-site substation is the responsibility of the developer.

However, the transmission connected customers can choose to construct their own connection as this provides some control over the costs and the timelines of the connection. This can only be done for works that are deemed to be "contestable". In such cases, the developer is responsible for detailed design, site and route selection, consents, equipment procurement and construction. System Operator will still have responsibilities such as specifying the connection method, providing the functional specifications, design approval, inspection during construction and commissioning of the assets.[61]

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[59] CER "Decision on First Stage Payments on acceptance of a Connection Offer to the Electricity Network" http://www.cer.ie/en/electricity-transmission-network-decision-documents.aspx?article=28f34878-65c1-436a-85e1-05db88781931

[60] The Consent Issue Date is the date when both the developer and the System Operator have obtained all consents required to begin construction work for the connection.

[61] "Connecting Renewable and CHP Electricity Generators to the Electricity Network", by SEI: http://www.seai.ie/Renewables/Bioenergy/Anaerobic_Digestion/How_to_get_grid_connection/Connecting_Renewable_and_CHP_Electricity_Generators_to_the_Electricity_Network.pdf

The contestability of a shared transmission asset is governed by the following rules: [58]

- All applicants that share the transmission asset must come to a unanimous agreement if the asset is to be made contestable. This must be notified in writing to the TSO and one transmission applicant will be selected to liaise with the TSO during the construction process;
- The shared transmission asset will be considered by the TSO to be non-contestable if there is no agreement within the sub-group;
- The payments for a contestable shared transmission connection asset will be arranged for within the sub-group. The commission has no obligation to protect any party from potential financial risk of unrecovered connection costs; and
- The TSO may choose to make a shared transmission connection asset non-contestable on the basis of security and stability reasons.

If the group chooses to contest the works then they will also be liable to costs of oversight by the System Operator to ensure that the works are built to the required specifications. Additionally they will have to pay for the cost of any non-contestable works.

If not all generators, directly/indirectly connected to the same node, accept their connection offer then the pricing principles may be revisited if necessary[52].

Regulation 33 of SI 445 (2000), states that the contestable assets:

"may, on request of the applicant, be on the basis that the applicant constructs, or that either or both the applicant and the transmission system operator arranges to have constructed, the connection to the transmission system, and any such connection constructed or arranged to be constructed by the applicant shall be the property of the person with whom the agreement is made, and shall, for the proposes of Section 37(4), be deemed to be a direct line".

However under Section 37 (4), CER has the power to direct the owner of the contestable connection to transfer the ownership of the assets to the TAO, upon application of the TSO. The assets will be transferred to the TAO under a nominal fee. The TSO will seek approval from the CER under section 37 of the Electricity Regulation Act 1999, under the following circumstances[62]:

- Where the assets that are (or are likely) to be shared by more than one party. This can be system users or connecting parties;
- Where it is deemed appropriate for the assets to be utilised to connect another party;

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[62] "Contestability of Connection Assets", EirGrid
http://www.eirgrid.com/media/Contestability%20of%20Connection%20Assets%20-%20Oct%202007.pdf

- Where the connection has been oversized with the aim of connecting further users or as part of overall system developments. Note that in this case, the TNUoS customers would have contributed to the cost of the assets;
- Where it is deemed appropriate for the assets to be utilised as part of wider system development; and
- Where another party or system users might be affected by the performance of the assets in question. This includes the cases where ownership and maintenance of the assets is important for system security or protection of the integrity of the system.

Stranded Assets

In the event that a developer chooses to modify the connection and as a result is no longer connected to the shared connection assets, a stranded asset cost may arise. Note that the possibility of a stranded cost arising greatly depends on the timing at which the request was submitted[63]. This cost will not be distributed among the remainder of the group or the TNUoS and will have to be borne by the developer.

Grid Upgrade Development Plan (GUDP)

The GUDP is a European Union funded programme in order to develop electricity assets to connect renewable generation. The following charging rules apply:

- Distribution assets:
  - Charges to be calculated as follows:

    ((Cost of asset)*(MEC of connecting generator))/60MW
- Transmission assets:
  - Charges to be calculated as follows:

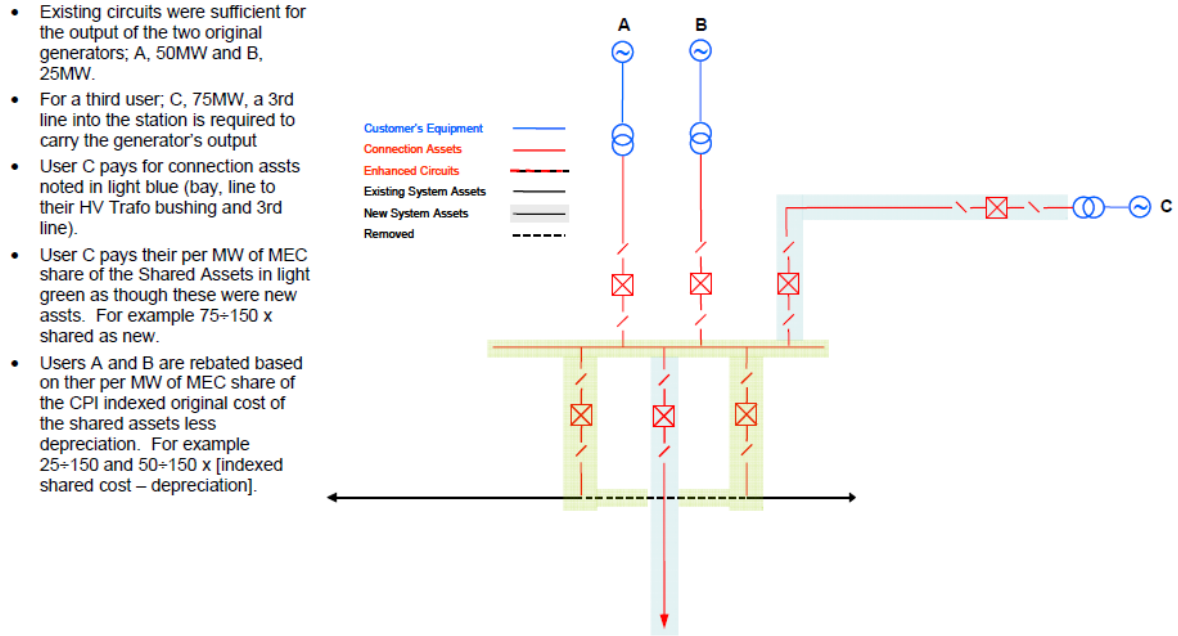
    ((Cost of asset)*(MEC of connecting generator))/70MW

Shared Connection Example

The following figure provides and example of a possible group connection and the charges incurred by each party[64]:

[63] CER "Appendix A - Connection Policy and Process - cer11093" http://www.cer.ie/en/electricity-distribution-network-current-consultations.aspx?article=f60275f5-1442-4330-93f3-895a68f861b3

[64] Transmission Connection Charging Methodology Statement", EirGrid: http://www.eirgrid.com/media/Connection%20Charging%20Statement.pdf



- **Figure 7 Example of potential group connection and charges incurred**

C.2.6 Pre-commitment and anticipatory investment

Transmission connected applicants must put down a Connection Charges Bond on the Consent Issue Date[60]. This will cover any additional costs arising from shallow works that have not yet been included in the applicant's payments. This is drawn down if the project does not connect and EirGrid's costs incurred exceeded the sums already paid.

Two years after the Consent Issue Date and less than one month before energisation, any renewable developments above 5MW must submit a Capacity Bond of EUR 25,000 per MW of the MEC. This is to ensure that there is no "hoarding" of transmission and may also be used to cover any deep reinforcement works in the event that the bond is drawn down. The basic principles surrounding the Capacity Bond is provided below[63]:

- If 95% of the MEC is not achieved within 1 year of energisation the capacity bond will be drawn down accordingly and the MEC reset to the maximum generator output over the course of the year.
- If a request to reduce the MEC is put in place, then a portion of the capacity bond will be drawn down.
- If the Operational certificate has been issued and at least 95% of the MEC has been achieved, then the developer may request that the Capacity Bond is returned before the 12 months after energisation.

- Post energisation, each year that the developer does not obtain the Operational certificate, the capacity bond will be drawn down. If the Operational certificate is not granted within four years, then the full capacity bond will be drawn down and the connection agreement will be terminated.

There is no longer any requirement to post a Decommissioning and Reinstatement bond as the cost of the bond was considered to be too high compared to the risk faced by the System Operator.

C.2.7 Summary

Ireland provides a good example of the way in which periodic planning and coordination should be able to minimise the cost of transmission investment to connect new generation. In some respects this is just a less frequent version of the proposed German off-shore coordination approach.

C.3 Public contest in the Argentine onshore electricity transmission sector

A novel approach to onshore electricity transmission network expansion has been available in Argentina since 1992.[65] Legislation requires that investment in the transmission network must be determined and funded by the private sector.[66] To fulfil this requirement, the "Public Contest" (PC) method ("concurso público" in Spanish) has been developed to make and approve major transmission expansions that would affect multiple parties.

Under PC, users of the network (distribution companies, generators and major consumers), rather than the network concessionaires or regulators, are responsible for initiating and approving major expansions. [67] This places most significant investment decisions in the hands of those who use and face charges for these projects.

ENRE[68] (Ente Nacional Regulador de la Electricidad), the national regulator; the Energy Secretariat[69] (Secretaria de Energía) at the Ministry of Federal Planning, Public Investment and Services (Ministerio de Planificación Federal, Inversión Pública y Servicios); and CAMMESA[70] (Compañía Administradora del Mercado Mayorista Eléctrico), the wholesale electricity market administrator have important roles in this process.

The PC process

A number of steps must be followed to secure PC expansions but the ultimate goal is for private sector "proponents" to secure approval from ENRE in the form of a "Certificate of Convenience

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[65] Market Regulations (SE 137/1992) Annex 16
[66] Electric Energy Regime – Law Number 24.065, http://mepriv.mecon.gov.ar/Normas/24065.htm
[67] Regulators only have limited power to veto or adjust PC decisions and the Secretary of Energy can propose expansions on security of supply grounds.
[68] See http://www.enre.gov.ar/
[69] See http://www.energia.gov.ar/
[70] See http://www.cammesa.com/

and Public Necessity," at which point a construction, O&M contract for the project can be tendered competitively.[71]

- **Step 1** – Proponents apply to transmission concessionaire

  One "proponent," or several acting together, can submit a PC application to their local transmission concessionaire for a PC expansion. This includes technical information for the concessionaire and ENRE to check it complies with regulated standards.[72] The receipt of their application initiates a regulated process with specific milestones required within fixed time periods.

- **Step 2** – CAMMESA assessment

  CAMMESA are responsible for identifying the "beneficiaries" eligible to vote on any proposed scheme. They use a methodology based on an "Area of Influence" approach. This approach requires estimation of the expected impact of the project on electricity flows. Beneficiaries are identified as those where an increase in their generation or consumption would result in an increase in flow along the extension. Weighted voting rights are allocated based on modelled "participation" over the two years following energisation. CAMMESA use the same methodology to set network capacity charges for these users. They must respond to the concessionaire with their results within 45 days.[73] The model used for these calculations must be approved and any changes authorised by the Energy Secretariat.

- **Step 3** – ENRE application

  The transmission concessionaire must submit an application for approval from ENRE within 60 days of the initial PC request.[74] This application must be supported by a technical feasibility report and the CAMMESA report.

  ENRE can only approve PC projects that have been proposed by parties that represent at least 30 percent of the modelled benefits, based on the submitted CAMMESA report.

- **Step 4** – PC announcement

  If the application is feasible and has sufficient support, ENRE must publish a public request including:

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[71] Romero (1998) "Regulación e Inversiones en el Sector Eléctrico Argentino" http://www.eclac.org/publicaciones/xml/8/4268/lcl1145e.pdf
[72] Littlechild & Skerk (2004) "Regulation of Transmission Expansion in Argentina: Part I – State Ownership, Reform and the Fourth Line" http://www.eprg.group.cam.ac.uk/wp-content/uploads/2008/11/ep62.pdf
[73] Ibid.
[74] Ibid.

- annual fees for the project;
- the fee amortisation period (typically limited to less than 15 years);
- the beneficiaries identified by CAMMESA; and
- beneficiary shares of the annual fees.

ENRE must arrange a public hearing within 30 days of the request.

- **Step 5** – PC

  The identified beneficiaries vote on each project. If a minimum of 30 percent support the project and less than 30 percent oppose the project, it is passed on for regulatory approval.[75] In cases where ENRE judge oppositions to be justifiable, but they are insufficient to block the project, ENRE have the power to commission independent consultants for judgement, and can intervene within 90 days.[76]

- **Step 6** – Golden rule

  At this point, the project will go ahead unless it fails ENRE's "Golden Rule" test. The Golden Rule requires the project to reduce "the sum of investment, operation and outage costs in the system as a whole."[77]

- **Step 7** – Approval

  PC projects completing the above steps receive approval from ENRE in the form of a "Certificate of Convenience and Public Necessity." With the certificate from ENRE, the PC proponents must then arrange a public tendering process and award the project as a Construction Operation and Maintenance contract awarded to the bidder with lowest amortised fees.

Alternative approval routes

Argentine market regulations allow two further approval routes for network expansion in certain circumstances:

- Minor expansions – the transmission concessionaire is responsible for expansions costing less than USD 2M. Fee amortisation can either be agreed directly with the users or ENRE can authorise and allocate contributions between users.
- Contract between parties – a streamlined form of PC is available for cases with a limited number of beneficiaries. The transmission concessionaire must send ENRE requests with

[75] Ibid.
[76] Ibid.
[77] Littlechild & Ponzano (2007) "Transmission expansion in Argentina 5: The regional electricity forum of Buenos Aires province" http://www.dspace.cam.ac.uk/bitstream/1810/195431/1/0762%26EPRG0729.pdf

its own analysis in less than 30 days. ENRE organise a public hearing within a further 30 days and if there is no well founded opposition, the project is approved.

Buenos Aires forum

One reaction to the PC regime was the coordination of network users in Buenos Aires Province as a Regional Electricity Forum, FREBA[78] (Foro Regional Eléctrico de la Provincia de Buenos Aires), to develop and implement a coordinated expansion plan in its region. FREBA includes distribution companies, and municipal distribution cooperatives. The regional transmission concessionaires are permanent advisory members.

FREBA coordinates investment projects, engages with the regulators on policy development. They also fund the projects shortlisted and approved by their General Assembly, where voting power is based on MWh network demand. Investment is funded by an "Aggregate Tariff" charged to consumers and through a mix of mandatory and voluntary contributions from distribution companies.

In Argentina, transmission companies must present suggestions for quality of service investments required to maintain standards for the next eight years, but cannot implement them directly. FREBA develop ten year expansion plans, and within three years of cooperation with the concessionaires, these plans were exactly matching.[79]

Performance and criticisms

The success of a PC-type system rests on the assumption that generators will propose investments to ensure they can sell their electricity and that distribution companies will propose investments to meet their performance targets in their concessions. The performance of the Argentine mechanism in the 1990s is relatively well documented,[80] but appears to have fallen out of favour in recent years.

There were initially criticisms of the public tendering process and doubts that it could work in certain situations such as a meshed network design. However, Littlechild[81] found that the result of the process has been the better use of existing capacity, rather than construction of new lines. There are no aggregated statistics publicly available on the level of PC-driven expansion over time.

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[78] See http://www.freba.com.ar/
[79] Littlechild and Ponzano (2007) "Transmission expansion in Argentina 5: the Regional Electricity Forum of Buenos Aires Province" http://www.dspace.cam.ac.uk/bitstream/1810/195431/1/0762%26EPRG0729.pdf
[80] See http://rru.worldbank.org/documents/publicpolicyjournal/192abdal.pdf for example.
[81] Littlechild and Ponzano (2007)

C.4 Texas Anticipatory investment

C.4.1 Introduction

Texas's electricity market is served by the Electric Reliability Council of Texas (ERCOT) operates the electric grid and manages the deregulated market across 75% of the state. The remaining 25% of the state (in the sparsely populated but high wind capability area of the Panhandle) is run by SPP, which also serves Kansas, Oklahoma, and parts of five other southern states.

ERCOT sees nearly 80% of its energy produced by fossil fuels (coal and gas) but an increasing amount of energy (6%) is produced by wind power.[82] This developed under the Renewables Portfolio Standard approach in 2002, which obliged electricity providers to obtain new renewable energy capacity based on their existing market share. This was so successful that Texas met its ten year renewables target in six years: however, wind investment followed existing transmission lines (to avoid the cost of creating additional infrastructure) rather than in the most optimal locations. This led to the situation where wind generators were forced to reduce their output due to congestion on the transmission grid (wind curtailment) and where local nodal spot prices fell to zero. This occurred in the McCamey area in 2000, and later in the Sweetwater area in 2008.[83] This meant that prices for wind energy could be negative in some regions. However, this still constituted a transfer of wealth from federal tax payers to the energy market, as the subsidies and benefits are still paid even when the electricity is not used.[84]

In 2005, the Competitive Renewable Energy Zone (CREZ) scheme was put in place to overcome these issues.

C.4.2 Anticipatory Investment[85]

In 2005, the Texas State Senate passed the bill creating the Competitive Renewable Energy Zones. This made the Public Utility Commission of Texas (PUC) responsible for overseeing the CREZ process, including designating CREZ, selecting transmission service providers (TSPs), and providing reports to the legislatures. The Zones were chosen following a wind study undertaken by ERCOT, as well as through a process that allowed any interested party to nominate a region for consideration as a CREZ.

Regions were considered based on: the wind production capability of the region, the financial commitment level from generators in the region, and other factors including the cost of transmission and the benefits of renewable energy in the zone. ERCOT published a report that

[82] Pöyry (2010) 'Electricity Transmission Use of Systems Charging: Theory and International Experience'
[83] Diffen (2009) 'Competitive Renewable Energy Zones: how Texas is cracking the chicken and egg problem'
[84] CEE (2009) 'Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones'
[85] Adapted from Diffen (2009)

high-lighted the 25 top priority regions based on wind capability. Following a long process, including a long legal process where many interested parties set forth potential projects across 16 zones, this was whittled down to five zones. These were determined by:

- Sufficient renewable energy resources;
- Suitable for wind development;
- Non-renewable generation available to provide ancillary services such as backing up wind by ramping up as wind output decreases;
- System reliability;
- Environmental sensitivity;
- Economics; and
- Geographic diversity.

A challenge arose from the fact that power generated in the panhandle, were it to be connected to the SPP grid, would allow other states connected to the grid to free ride off the investments made by the Texan people. However, in the final instance, a plan was chosen that avoided this option, but was more costly than may have otherwise been the case.

The final plan developed ensured that the CREZ scheme would be beneficial for wind farms as well as for the entire electrical grid, preparing for future upgrades and possible future CREZ schemes. This is set to support a total of 18,456MW of renewable generation- 11,552MW of new wind and 6,903MW of existing and under construction projects. The cost was estimated at the time to be USD 4.93b (with a collection systems cost of circa USD 580-820M) for building 2,334 miles of transmission lines. This should provide for an estimated 64,031 GWh of wind generation and fuel savings on average of USD 38 per MWh. It is expected that this plan will cost on average USD 4.04 a month on residential customer's bills.[86]

Benefits of the scheme

Whilst there have been many criticisms of the scale of this investment, it is estimated that under some projections, all the costs associated with CREZ transmission built will be covered once the wind farms have been generating electricity for 18 months, as there will be no fuel costs. In addition, the upgrades will improve the transmission system generally.

Innovative methods were developed to ensure the flexibility of the CREZ scheme, through the selection of TSPs. After the zones were identified, TSPs were selected. These were chosen based on their financial strength and flexibility. However, this allows competition for the opportunities to build new transmission to serve a CREZ, which should lower prices for the projects.

[86] Navigant Consulting (2008) 'CREZ: Are we there yet?'

Dispatch priority

It was key to developers that those who had participated in the CREZ development process be given dispatch priority. Curtailment had already proven a problem in Texas by this point and it was expected that when transmission was developed, farms would again cluster around these areas, causing further curtailment. The firms who had been involved in the development process for CREZ (sharing confidential information, and providing deposits to fund the scheme) felt that they would be provided dispatch priority to reflect this early commitment. Curtailment of only 5% is estimated to lead to a wind farm losing 45% of its revenue, so this was clearly an important issue for developers.

The preferred solution of dispatch priority was problematic for the regulator, because of the 'open access' framework it developed: dispatch priority that is not based on the lowest price interferes with the free workings of the market. However, in mid-2009, dispatch priority was acknowledged as necessary by the PUC, and this appears to have been implemented to some extent.[87]

Renewable Energy Transmission Initiative (RETI)[88]

Like Texas, California has had great success in developing renewable energy within its state, and now it is struggling from the lack of capacity in its transmission network. The TSO's interconnection queue currently contains over 40,000MW of renewable generation projects. RETI is a statewide initiative to identify the transmission projects required, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting.

RETI will assess all competitive renewable energy zones in California (and possibly also in neighbouring states), and identify those zones that can be developed in the most effective way. RETI will be supervised by a selection of public bodies:

- California Public Utilities Commission (CPUC)
- California Energy Commission (Energy Commission)
- California Independent System Operator (CAISO)
- Publicly-Owned Utilities (SCPPA, SMUD, and NCPA)

This appears to still be at a very early stage of development. Phases 1 and 2 have been completed, and the projects have been selected.[89]

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[87] PUC (2009) 'Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones'
[88] Adapted from: http://www.energy.ca.gov/reti/index.html
[89] RETI Coordinating Committee (2010) 'Phase 2B: Final Report'

C.4.3 Summary

The CREZ results are an innovative way to overcome the transmission issues posed by renewable energy development, and the inappropriate incentives that this can create. Whilst this is a large and costly investment in the transmission system, it ensures that wind energy is placed where it is most effective. It success is reflected in its replication in other states, such as California, Colorado, Nevada, Arizona, New Mexico, and Utah.[90]

C.5 Open Season Procedures

C.5.1 Introduction

Open Season procedures have been used as a way of providing new infrastructure, both in the US and a number of European countries. In Europe, the European Regulators' Group for Electricity and Gas (ERGEG) published guidelines on good practice on Open Season Procedures for the Gas industry. Open season methods are not as well developed in the European electricity markets.

In the US, in 2007 the Federal Energy Regulatory Commission (FERC) made it compulsory for all electricity transmission planning processes within its jurisdiction to meet its new criteria focusing on coordination, openness, and economic planning. A number of jurisdictions met these requirements through developing open season processes, based on the experiences of the gas industry.[91] TSOs that have adopted this method include CAISO in California, Bonneville Power Administration in Portland, and the Wyoming Infrastructure Authority in Wyoming. Below, the European guidelines for gas transmission are summarised, and details are provided on the open season methods that were developed in the Californian context.

C.5.2 ERGEG good practice[92]

The European regulations in the gas market require TSOs to provide for efficient capacity allocation mechanisms and congestion management procedures, and infrastructure should be made available on a non-discriminatory basis, at a fair price.

To do this, it is key that the system operators meet any reasonable demands for the transportation of gas from the shippers. Any congestion, that is neither temporary nor can be resolved by efficient transmission management, should be resolved by improvements in the infrastructure.

Within this context, open seasons are a market test to show the agent sponsoring a transmission project (which could be the TSO, or if the TSO in not in a position to fund the infrastructure then an outside investor) how much infrastructure a market wants. In addition, the tool can also be used

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[90] Hulburt (2009) 'Transmission Development Zones for Renewable Energy Resources'
[91] Fink et al (2011) 'A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organisations'
[92] Adapted from ERGEG (2006) 'Draft Guidelines of Good Practice on Open Season Procedures (GGPOS)'

to allow SOs or other project sponsors to consult future users regarding the terms capacity should be sold at, and they also can be used to allocate capacity in a non-discriminatory manner.

ERGEG recommends that the open seasons works through a two step process, where there is an open assessment of market demand for a specific proposal, followed by a phase of capacity allocation. Both phases are conducted by the sponsor of the project, who will sell on the capacity to the market. An open season may be initiated when:

- A TSO decides to enhance the system;
- A new infrastructure is going to be built by a project sponsor; or
- The regulatory authority requires it.

Before the open season, the sponsor should consult with the system users to assess how much capacity the market needs as well the terms that will be required, surrounding issues such as price, contract duration, and the firmness of the capacity. The economic and technical constraints should be considered should also be considered at this stage. Then, potential users are informed about the planned project, and it is recommended that the project sponsor gives as much information as is feasible at this stage.

Interested parties then indicate the amount and type of capacity they would like for each proposed route, and suggest changes to the proposal at this stage. Even if it becomes apparent at this stage that there is insufficient demand for the project, ERGEG suggests it is still appropriate for the sponsor to go ahead if it believes that sufficient demand will develop in the future, and it is willing to take on the financial risk itself (anticipatory investment).

In the second phase of the open season process, the sponsor should offer capacity according to that already committed to by the interested parties. Initially, ERGEG recommends that this be a non-binding commitment such as a pre-contractual 'Letter of Intent'. Once the capacity has been allocated, the bidders and the sponsor can enter into a binding agreement, including providing any guarantees that the sponsor requires.

The good practice recommendations made by ERGEG have already been put into place: for example in Denmark, in the Open Season 2009, the market players indicated that a looping of the Ellund-Egtved pipeline (linking Germany and Denmark) and a new compressor station were of main importance for the Danish market, reflecting the decline of Danish natural gas stocks and its self-sufficiency in gas. This link will be able to transfer 700,000 m^3 of natural gas per hour from Germany when completed.[93]

[93] Taken from http://www.energinet.dk/EN/GAS/Det-danske-gasmarked/Sider/Open-Season.aspx

C.5.3 The Californian context

In California, FERC's Order 890 (Preventing Undue Discrimination and Preference in Transmission) for electricity transmission were integrated into the CAISO workings in late 2007. This is a somewhat different system to that recommended in the EU gas market, as the open season can be used for information requests and studies into effective transmission management.

The 'open season' for CAISO's market consists of a year-long window when stakeholders submit their proposals to be evaluated by CAISO. Requests that pass the CAISO selection requirements are included in the transmission plan as planning assumptions. If there are a large number of valid requests, they are put into an 'interconnection queue'. Submitting proposals through the open season is a four stage process:

- Initiate the process. This is done by submitting the request for the study to CAISO.
- The selection criteria are applied
- An agreement is reached between the sponsors and CAISO
- No later than at the end of the open season, all of the components of the projects such as location, models for technical studies etc are submitted to CAISO.

There are three forms of submission that can be put through CAISO's 'open season' programme:

- Transmission project proposals (as seen in Europe). Those that propose a study will be expected to cover any costs incurred.
- Requests for studies. Stakeholders may request that CAISO conduct studies to address congestion in the current system. This can also include requests for integrating new resources of load to existing transmission.
- Demand responses and other information or requests: in addition to transmission and integration of resources, demand response and other information related to the transmission plan such as long-term power supply plans may be submitted.

Once submitted, these are subject to testing by CAISO, based on a number of selection criteria. These are:

- Consistency with the CAISO Transmission Plan;
- The proposal should not duplicate with any other projects already approved by CAISO; and
- It is a high priority project.

Whilst successfully passing through the open season tests does not guarantee the approval of the project, as it is then passed on to the management for analysis of the costs and benefits of the project.

C.5.4 Summary

Open season based systems provide a good example of what is a tried and tested process to determining whether shared assets are necessary and determining the user commitment to support those assets. It ought to be possible for there to be a way in which the existing British offshore electricity transmission point to point approach could adopt some form of open season as a way of determining whether shared assets were appropriate.

C.6 HVDC Interconnectors

C.6.1 Introduction[94]

HVDC is seen to be the most efficient method of transmitting power over long distances as there are lower capital costs and lower power losses compared to AC transmission. The first commercial HVDC installation was in 1954 and since then there have been a large number of HVDC projects around the world.

In alignment with the drive for a common European Electricity market, there has been a further increase in the number of HVDC interconnections projects between European countries. The following table presents some of the existing HVDC interconnections between European countries.

- **Table 4 Summary of some existing HVDC interconnections between European countries[95,]**

Country:	UK-NL	SE-FL	NO-NL	SE-PL	DK-DE	SE-DE
Name	BritNed	Fenno-Skan 2	NorNed	SwePol	Kontek	Baltic-Cable
Location 1	UK - Isle of Grain	Sweden - Finnbole	Norway- Feda	Poland - Bruskowo Wielkie	Denmark - Copenhagen	Sweden - Trelleborg
Location 2	Netherlands - Maasvlakte	Finland - Rauma	Nethherlands - Eemshaven	Sweden - Stärnö	Germany - Rostock	Germany - Lübeck
Capacity (MW)	1000	800	700	600	600	600
Voltage (kV)	450	500	450	450	400	450
Cable (km)	260	200	580	245	170	250
Project Costs	600M €	315M €	600M €	N/A	N/A	EUR 200M
Date Completed	2010*	2011	2008	2000	1996	1994

[94] http://en.wikipedia.org/wiki/High-voltage_direct_current
[95] http://en.wikipedia.org/wiki/List_of_HVDC_projects

There are a number of areas in HVDC transmission that relate closely to the subject of interconnections between OWFs. This is mainly as the interconnection between two countries will require some form of co-ordination. This case study examines HVDC interconnections in Europe, with a focus in the following areas:

- Ownership and responsibility of the assets;
- consent process;
- charging and trading; and
- anticipatory investment.

C.6.2 Regulatory framework[96]

Strong links between the European power grids have been recognized by the European Union as essential for the development of an internal European market and thus have received considerable support and backing. The trans-European energy networks (TEN-E) sets out guidelines to promote interconnection, interoperability and development between European countries. This extends to HVDC interconnections projects between countries.

In addition to this, European coordinators are appointed, under the guidelines of TEN-E, in order to monitor and facilitate the implementation of the projects identified to be the most critical. Details of these are included in the "Priority interconnection Plan". The coordinators will monitor, for duration of four years, the projects facing technical political or financial difficulties.

C.6.3 Ownership and responsibilities

A study of the recent HVDC interconnections between countries, elements of which are reproduced in Table 1, has high-lighted three main methods employed to deal with the shared assets:

- The TSOs agree to own and fund the link between them.
- The TSOs form a joint venture company that funds and owns the link. In some cases, each TSO has an equal share of the company (e.g. National Grid and TenneT each have 50% shares in BritNed[97]) while in other cases there may be a majority shareholder (e.g. Swedish Kraftnät has a 51% capital share in SwePol Link AB[98]).
- A third party funds and owns the link (e.g. Baltic Cable AB is 100% owned by Statkraft Energi AS a Norwegian Utility[99]).

Examples of the methods used in the existing interconnectors are provided in Table 2.

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[96] http://ec.europa.eu/energy/infrastructure/tent_e/ten_e_en.htm
[97] https://www.britned.com/Pages/default.aspx
[98] https://www.nordicenergyregulators.org/upload/Reports/CMGuidelinesImplementation.pdf
[99] http://www.balticcable.com/aboutindex.html

Generally the funding is recovered from the users and does not play any part in either country's national grid tariffs. Under the TEN-E policy, HVDC interconnection projects may receive financial backing through the TEN-E if they are shown to be of "European interest".[100] Examples for the funding of some recent projects are provided in the table below.

- **Table 5: Funding and ownership examples'**

UK-NL	SE-FL	NO-NL	SE-PL	DK-DE	SE-DE
Joint Venture, Equally owned by TSOs (BritNed)	Shared equally between TSOs	Shared equally between TSOs	Joint Venture, with majority shareholder (SwePol Link AB - 51% owned by Swedish Kraftnät)	N/A	Third party (Baltic Cable AB - 100% owned by Statkraft Energi AS, Norwegian Utility)

- **Table 6: Example of TEN-E funding between 1995-2009[101]**

Year	Description	Financing by TEN	Total	Total Project Cost	% of total project cost funded
BritNed - (UK, NL)					
2009	Part construction	1.075M €	11.722M €	600M €	2%
2006	Development study	2.669M €			
2004	Engineering, construction contract tendering and environmental permitting (phase 3b)	1.000M €			
2003	Engineering, construction contract tendering and environmental permitting (phase 3a)	1.625M €			
2002	Engineering, Environmental and Financial Feasibility Study (phase 2)	0.800M €			
2001	Economic feasibility and engineering studies.(Phase 2b)	2.000M €			
2000	Feasibility study (Phase 2), including sea bed survey.	2.053M €			
1996	Economic feasibility and engineering studies (excluding sea bed survey).	0.500M €			
Fenno - Skan - (SE, FL)					
2006	Seabed survey	0.475M €	1.295M€	315M €	2%
2000	Pre-feasibility, pre-environmental and evaluation study.	0.120M €			

[100] http://ec.europa.eu/energy/infrastructure/tent_e/financial_aid_en.htm
[101] http://ec.europa.eu/energy/infrastructure/tent_e/doc/2009_ten_e_financed_projects_1995_2009.pdf

Year	Description	Financing by TEN	Total	Total Project Cost	% of total project cost funded
1996	Feasibility and technical studies, including laboratory tests: Finnish share.	0.225M €			
1996	Feasibility and technical studies, including laboratory tests: Swedish share.	0.325M €			
1995	Feasibility study: Increased electricity transmission capacity (Finnish side).	0.075M €			
1995	Feasibility study: Increased electricity transmission capacity (Swedish side).	0.075M €			
NorNed - (NO, NL)					
2006	Construction and operation by the TSOs	3.000M €	8.715M €	600M €	1%
1998	Grant to the investment.	4.215M €			
1996	Studies for electrode design and evaluation of reliability and availability, including submarine cable tests.	1.500M €			
SwePol - (SE, PL)					
1998	Grant to the investment.	2.320M €	3.460M €		
1997	Additional feasibility study including sea-bottom survey.	0.340M €			
1995	Feasibility study.	800M €			

Depending on the arrangements to deal with the shared assets, the responsibility of operating and maintaining the link seems to fall on the owners as well. However this is not always the case as can be seen with the SwePol link; the link is owned by the third party SwePol Link AB (100% Norwegian owned) but each half of the line is operated and maintained by the respective TSO. Furthermore in April 2007 the Polish TSO won, through a competitive tender, the contract to operate and maintain the Swedish side as well.

C.6.4 Consent process[102]

Consent to build a HVDC link is required from both countries. Often, each country or TSO will pursue the consents for their own side of the connection unless the construction arrangements fall with a third party. In some cases more, the HVDC cable may require the crossing of other territorial waters or existing obstacles such as pipelines/cables/etc and therefore additional consents and agreements will be required. In the case of the Norway Netherland link (NorNed), 24 licences in four countries and 22 agreements with existing cable and pipeline owners were required.

[102] http://www.tennet.org/english/images/NorNed%20-%20Europe%27s%20link%20for%20the%20future_tcm43-18745.pdf

C.6.5 Charging and trading

In general the operation of the HVDC links are based on commercial management and is therefore separated from the regulatory activities of the TSO. Trading is usually driven by the difference in prices in the countries. However this is not the case for interconnectors between countries within the same electricity market. For example the Swedish-Finland interconnector, Fenno-Skan 2, is simply an exchange of power within the Nordic Pool and therefore no commercial management is required.

The existing methods used for trading often include one or a combination of the following:

- Explicit Auctions – market participants can buy capacity and electricity. This can be done on a daily, monthly or yearly basis.
- Implicit Auctions – market participants can buy capacity as well as electricity in one single transaction. It is often based on a day-ahead-auction.
- Merchant Lines – Priority rights of the transmission capacity are allocated (e.g. to the owner). Power deals on short, medium or long-term basis may be contracted and any excess capacity may be sold accordingly.

Table 7: Summary of trading mechanisms employed

UK-NL	SE-FL	NO-NL	SE-PL	DK-DE	SE-DE
100% TPA Implicit and explicit auctions	Exchange within the Nordic market	Explicit daily auctions A market coupling is intended to be introduced based on implicit auctioning.	Merchant line. Remaining capacity is sold (with no restrictions as to who may purchase)	N/A	Merchant line. Option to sell remaining capacity to a third party is not utilised,

C.6.6 Pre-commitment and anticipatory investment

At present, the level of anticipatory investment for HVDC projects is limited by the technology. Converter and cable sizes are limited, while multi-terminal stations are still in the early stages of development.

C.6.7 Summary

Unsurprisingly, given the types of issues involved in HVDC Interconnectors, the main coordination concern is related to planning.

C.7 Australian Scale Efficient Network Extensions

C.7.1 Initial plans for Scale Efficient Network Extensions[103]

Following a review of the existing energy frameworks to consider their ability to accommodate the Carbon Pollution Reduction Scheme (CPRS), and the expanded Renewable Energy Target, the Australian Energy Market Commission (AEMC) recommended a new framework for the connection of clusters of generators to the electricity networks. This was called Scale Efficient Network Extensions (SENEs). This was to overcome the challenge to transmission caused by the fact that renewable energy sources are for the most part clustered in certain areas, often remote from the existing network, and to overcome the risk of stranded network assets.

The proposed scheme would require the Australian Energy Market Operator (AEMO) to identify possible geographic zones where there would be the likelihood of substantial scale efficiencies emerging from the development of extensions to these areas. It suggested that the factors that would determine this would be viability and timing of possible future generation projects, the size or length of the network assets required, etc.

A significant number of responsibilities were placed upon the network companies under this plan. Each company would be required to undertake a high level assessment of the credible options for the development of extensions from SENE zones to their own networks. They would have to report publicly on possible connection locations, capacities and indicative costs, taking into account any shared benefits and other implications for the shared network. If the company perceived the network assets associated with a SENE could deliver possible benefits for the shared network, it would be required to undertake a Regulatory Investment Test (this is a process that facilitates a market consultation process, applied to developments with solutions valued at more than AUD 5 million.)

For each SENE, the network business would be required to publish a planning report and connection offer. Following an assessment by the Australian Energy Regulator, generators would be in a position to sign the connection offer, and following this, the network company could start construction. It was planned that the price for the service would be a capacity base charge, determined by the forecasted generators connecting and funding the full costs of the asset.

There was the risk that if generators arrive late, or do not materialise, that the customers would be exposed to some of the costs, but they would receive payments if generators arrive early or in excess of what was forecast. The network businesses would have a constant revenue stream across the life of the asset.

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[103] Adapted from the Ministerial Council on Energy (2010) 'Rule change request- scale efficient network extensions'

To reduce the risk to customers, the planned scheme required at least one generator to commit to connecting to the new transmission network, and the judgements on future demand would be considered by the regulator and the AEMO, to ensure that the estimates were robust.

C.7.2 Developing options for the scheme[104]

These proposals were broadly supported by market actors at the high level stage, but the detailed plans proved less popular through the consultation process, due to the complex nature of the proposed rule and possible difficulties in implementing it.

Accordingly, five options were developed to adapt the scheme. The first two options were based on the original framework, with improvements in the risk mitigation mechanisms and some simplifications. The third and fourth options were developed from proposals put forward by Grid Australia, and the fifth would change the charging structure for generators. These options are summarised below.

- Option 1 planned to introduce a cost threshold trigger such that the SENE will only be built once 25% of the capital costs of the investment were underwritten by firm connection agreements with generators.
- Option 2 also included a cost threshold trigger, but also included further risk mitigation measures through the explicit application of an economic test. It also aimed to simplify the proposed framework by removing the regulated compensation arrangements, leaving these to be negotiated.
- Option 3 proposed applying the Regulatory Investment Test to the incremental capacity above that for connecting the first generator. The first generator would pay the stand-alone costs of its connection to the network, in the absence of a scale efficient connection. Subsequent connecting generators would contribute to that first generator's stand alone cost, and the cost of any incremental capacity justified by the Regulatory Investment Test would be covered by customers.
- Option 4 is a variation on the third option, but with a different cost recovery arrangement. This would have generators pay for the SENE over time. Customers would continue to underwrite the risk of asset stranding.
- Option 5 would have generators paying for their connection, but instead of recovering this as a negotiated service, a new type of prescribed service is introduced that is paid for by generators. Customers would still underwrite the cost of any spare capacity, but with a simplified charging framework.

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[104] Adapted from AEMC (2010) 'National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010: Options Paper'

C.7.3 Final Determination[105]

Following the publication of the Options Paper, twenty-two further submissions were received from stakeholders, which continued to demonstrate a divergence in views not only on what changes should be made, but also on whether any changes were actually required.

The Final Determination was published in June 2011, and is significantly different from the proposed papers because it does not compel anyone to bear the risk and cost of stranded assets. Instead, it attempts to provide a mechanism where opportunities for taking advantage of economies of scale are made obvious to all stakeholders.

It creates a new obligation on transmission businesses to undertake studies, when requested to, to reveal the potential opportunities for efficiency gains from the coordinated connection of expected new generators in a particular area. A study will assist potential investors to make an informed, commercial decision to fund a SENE.

Once a study is published, the decisions to fund, construct, operate and connect to a SENE will be made by market participants and investors. The Commission concluded that this can only occur when the benefits of building spare capacity in anticipation of future generation outweighs the risks of stranded assets, and this decision is best made by market participants or investors with the ability and incentive to manage that risk.

[105] Adapted from AEMC (2011) 'National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010: Rule Determination'

Appendix D Market Mechanisms

D.1 Introduction

This annex considers a series of short case studies that capture the role that the market can play in developing infrastructure. Some of the examples are from the energy sector while others focus on lessons from other types of infrastructure.

D.2 GB Gas Entry

D.2.1 Introduction

In 1998 capacity constraints at St Fergus, one of the key entry points to the national transmission system for gas from the UKCS (North Sea) led to concerns that either too little gas would be available for meeting peak winter demand or that the cost of that gas would increase significantly. The regulatory regime at that time was felt to be unable to meet the demands of the industry and consequently was reformed.

The reforms which started to be introduced from 1999 have radically changed the gas entry regime and include:

- using long-term and short-term auctions, where the long-term auctions allow purchase of quarterly blocks of capacity for a period of up to 17 years;
- underlying the auctions are marginal cost calculations which for long-term access are based on the incremental cost of new capacity and for short-term are based on the variable costs of the network, which are believed to be as close to zero as makes no difference;
- a revenue recovery scheme such that under-recoveries from the auctions are compensated through a commodity charge levied on all gas entering the British network; and
- new investment is triggered if user commitment, in terms of booked capacity at a price at least equal to the long run marginal (incremental) cost accounts for 50% of the new capacity.

The objectives underlying this regime were summarised by Ofgem as

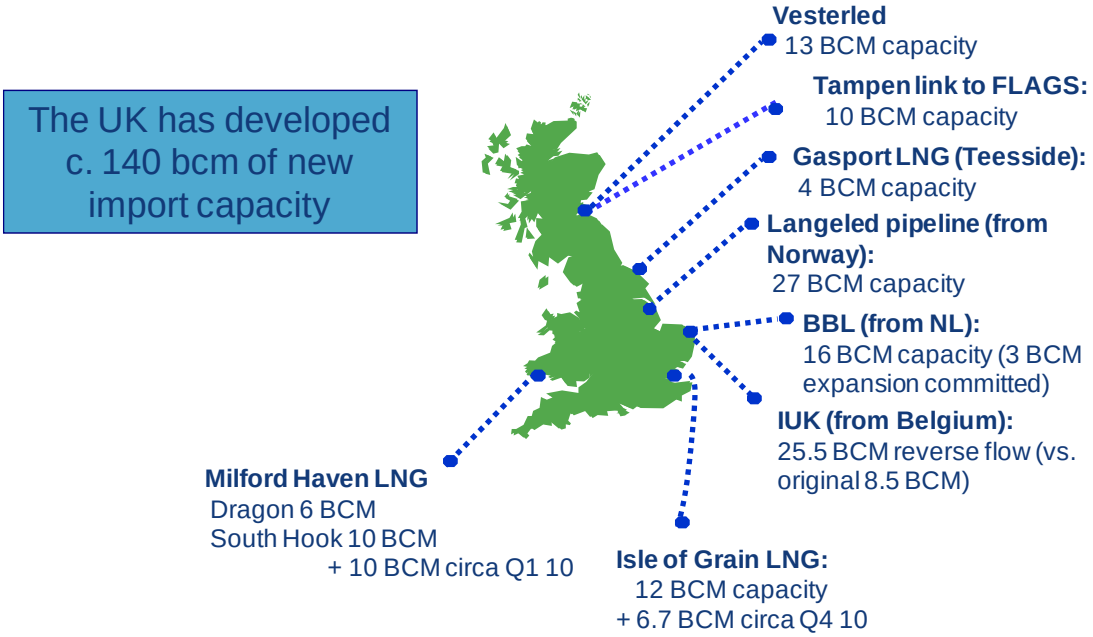
- providing a method of allocating a scarce resource that is efficient and non-discriminatory;
- providing signals for future network planning and investment (beyond the baseline contractual position); and
- facilitating efficient market operation and support the NTS network system operator incentive regime.

D.2.2 The user commitment scheme

Our primary interest in this case study is linked to the user commitment scheme. As noted above, only 50% of the incremental capacity had to be booked by users to lead to the investment taking

place – the costs associated with the remaining 50% are socialised across all users. This is different to the situation in offshore transmission where 100% user commitment is required.

Figure 8 below provides a summary of the capacity of new investment that has taken place in the entry system since 2000 (with the bulk of this occurring after 2005). As can be seen significant new investment has taken place – this is equivalent to about 10%-15% of the capacity that existed in 2000 (check the precise number).



- **Figure 8 New gas entry capacity developed since 2000**

About a third of the new capacity that has been added is linked to LNG which is important since it is not dependent on a single source of gas as is the case for much of the network.

D.2.3 Summary

The introduction of the new regulatory regime has clearly had a significant impact on the British gas industry. Capacity constraints were eased, especially after the Langeled pipeline from Norway opened 2006/7. User commitment has been a key element of this, but the socialisation of some costs has also meant that more general support for investment has existed.

While it is clear that the regime successfully addressed the capacity problem, whether it was just the regime is an interesting question. Whether the LNG terminals would have been developed without the support of the socialisation of 50% of the costs is an interesting counter-factual to

consider. Further, while there is now sufficient total entry capacity, , there may be insufficient LNG capacity.

If there is excess capacity then the question that needs to be considered is whether the additional cost linked to the investment was worthwhile. Transmission is about 3% of the final gas bill for consumers.

D.3 Case Study of UK Cable Television

D.3.1 1980s

Cable actually pre-dates WW2, but until 1982 and the Cable & Broadcasting Act, this service only offered the three main terrestrial channels. 1982 also saw the Telecommunications Act come into force. Cable TV is also known as Local or District Loop and this definition may prove to be more accurate due to transfer of data not solely down to television.

Following this Act, the Hunt Committee Report looked into Cable Expansion and Broadcasting policy in 1983, at the same time as issuing 11 interim franchises in the UK. In 1985, the Cable Authority was set up to oversee this expansion. The franchises were intended to last for 12yrs initially followed by 8yr periods after that. This financing was envisaged to come directly from the private sector and half the houses were owned by local government, who were set to play an important role too. In France and W. Germany, the government actually funded similar projects without the private sector.

In the ITAP Report of 1982, it was estimated that the overall scale of economic activity was approximately GBP 1b per annum, but the cost of laying cable for half the UK (mainly urban and densely populated areas) was GBP 2.5b.[106] Michael Aldrich, a leading author in this field, believed the debt would be amortised over a 20-25yr period.[107] He also stated that the view on cable changed significantly between 1982, when cable operators were seen as 'quick buck' exploiters, to 1983, when people believed cable was a licence to lose money.[108] In 1985, the payback periods of the cable networks were seen as being as long as the North Sea oil investments.[109] A different report puts the installation costs at GBP 25-30M for a franchise area of around 100,000 people.[110]

There were some stipulations attached to such franchises, but there was unlimited channel capacity and no mandatory controls existed on pricing or advertising. The operators were restricted to one

[106] http://www.aldricharchive.com/papers/1982/The%20Significance%20Of%20The%20New%20Cable%20System%20Sept'82.pdf
[107] http://www.aldricharchive.com/papers/1982/Cable%20Systems%20-%20Implications%20For%20UK%20Industry%20July'82.pdf
[108] http://www.aldricharchive.com/papers/1983/Cabling%20Britain%20-%20Whate%20Relevance%20For%20IT%20June'83.pdf
[109] http://www.aldricharchive.com/papers/1985/The%20International%20Cabled%20City%20Feb'85.pdf
[110] p.225 Gibbons et al 'Cable Tele' file in S-Drive

area each and some channels had to be leased to others at a reasonable price. There was also a requirement to carry both BBC and ITV channels. A minimum performance standard has been attached to cable systems to prevent installing soon-outdated technology. This though raises the cost of investment by 30% with few immediate commercial benefits.[111] Also, there were 20yr licenses granted to operators producing more technologically advanced 'switched star' layouts rather than 12yr licences for simplistic 'tree and branch' layouts.[112]

The opportunity to lobby the government and establish a position as an operator in the industry meant that there was a first-mover advantage and consequently many firms over-bid for what they could actually offer.

The role of BT

BT were always able to purchase franchises, but wanted to develop their own national cable network. They did own some franchises, which were largely sold on by 1999, due to their position in the BIB Joint Venture making the European Commission force them to sell it. The major competitors to BT at the time were Telewest and Nynex, who attempted to undercut BT's prices, but struggled to do so without consolidation. BT were not allowed to offer multi-media services through their existing network, but by offering individual pay-per-views content they could circumvent this rule to an extent. BT was privatised in 1984 and their monopoly position ended in that year with the emergence of Mercury Communications.

The role of North American Investment

The UK was the first place where a single company could offer both television and telephony via cable. The possibilities for experimentation and multimedia attracted largely US investment, as they had not been able to crack their domestic market. The UK also had very modern fibre optic and co-axial networks to assist the roll-out of broadband internet, yet this increased the costs of creating such networks. The idea for this was for it to be 'future-proof.' A quote from the vice-president of a Canadian firm, Telus, who had just invested in CUC Cablevision was 'the experience of the UK market as a chance for pre-positioning, so we can take advantage of the additional revenue opportunities that may occur if the Canadian cable and telephone markets are allowed to converge.'[113]

Why did this fail?

The telephony service proved successful, but a combination of reasons led to cable not being successful. The first of these was the development and low cost of satellite receivers, the high quality reception of terrestrial TV and the poor image of cable with the more affluent demographic.

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[111] p.228 Gibbons et al 'Cable Tele' file in S-Drive
[112] p.592 Cornford & Gillespie 'Cable TV' file in S-Drive
[113] p.594 Cornford & Gillespie 'Cable TV' file in S-Drive

D.3.2 1990s

The 1990s saw GBP 12b of investment, with the anticipated amount necessitated to lay ducts being around GBP 16b. Machines were developed that were capable of threading cables along existing sewers and pipelines. Churn rates for cable subscribers were often very high (40-50%) and regional suppliers made consumers sceptical of the quality of service they were being offered.

A particular element of development was the disparities between geographical regions in terms of competition. As Cornford & Gillespie note, certain areas had a BT monopoly, where others had three firms in direct competition with one another.[114]

Conclusions from 1990 franchise bidding:

"There were forty bidders, four lost their existing licenses (TVAM, Thames, TSW and TVS), thirteen failed the quality threshold, eight franchises did not go to the highest bidder, two were said to have overbid in losing their licence (TVSW and TVS) and two underbid (TVAM and Thames). Around two thousand jobs will be lost, highly skilled and experienced people will become unemployed not due to the market deeming that their products were not good enough but because the state deemed it. The choices made seem at best arbitrary. No winner has stuck by what it proposed, TVAM, the most profitable TV company in the world (per viewer), has lost and Thames, which produces thirty percent of the network, has also lost. This would not have happened in a market situation. The blind bids have not produced market prices for the channels as intended. Compare Carlton's GBP 43.2 million a year to Central's GBP 2,000.15 Central may become the strongest ITV channel because of this and not because of its market skill."

Many of the shows were also dependent on BSkyB, a direct competitor from the satellite TV market. They forced cable suppliers to carry 100% of their basic channels to each subscriber, meaning packages could not be easily tailored to certain groups. BSkyB also had independence in setting costs to cable suppliers and such price discussions lacked transparency.

By 1999, all but six of the UK's 136 operational franchises were owned by NTL and Telewest, themselves owned by US investors. Within these franchises, a roll-out obligation existed. According to the Competition Commission Report this was 68% of the national population for NTL for their licences from 1999.

D.3.3 2000s

The 2000's saw a mixture of bankruptcies and the process of consolidation was a prominent feature of this period. NTL went through Chapter 11 reorganisation in 2003 and Telewest suffered post-tax

[114] p.601 Cornford & Gillespie, 'Cable TV' file in S-Drive

losses of GBP 2,227M in 2002. These firms later merged in 2005 and then purchased Virgin Mobile in 2007 to become the entity 'Virgin Media.'

In the case of Telewest and NTL, both took on extraordinary amounts of debt to roll out their cable networks, yet following the burst of the dotcom and telecoms boom they suffered a fall in market capitalisation of GBP 200M between 2000-2. The two firms were further pressured by the roll-out of digital free-to-air TV in the UK to replace analogue signals.

D.3.4 Current scenario

Country	Cable television subscribers as proportion of households passed (%)
Canada	63.5
Canada	65.4
Austria	48.4
Ireland	61.3
Belgium	86.8
Hungary	71.4
Japan	20.9
Netherlands	74.6
Netherlands	80.6
Switzerland	83.3
Poland	51.1
United Kingdom	28.7
Spain	26.6
United States	81.1
United States	47.8
United States	68.7
United States	68.7
United States	65.7
Portugal	56.7
Germany	58.9
Mexico	35.7
France	37.2
Czech Republic	52.2
Slovak Republic	60.1
Korea	67.6

As you can see, the UK is third lowest on the proportion of Cable TV subscribers with the service available to them. (N.B. Some countries are listed multiple times due to different measures).

Cable and Satellite Penetration 1986 - 1999

Cable figures represents % take up in cabled areas.

Year	Cable	No. of Subscribers (m)	Satellite	No. of Subscribers (m)
1986	12.2%	-		
1987	13.3%	-		
1988	14.3%	-		
1989	14.5%	-		
1990	16.5%	-		
1991	19.1%	-		
1992	21.5%	-		
1993	21.1%	-		
1994	22.0%	0.91	13.1%	3.96
1995	20.8% (1)	1.16	15.0%	3.28
1996	22.4% (2)	2.24	17.0%	3.79
1997	22.2% (3)	2.30	18.0%	4.30
1998	23.7% (4)	2.70	17.0%	4.10
1999	25.7% (5)	3.20	17.0%	4.10

(1) 5.2% represents national figure

(2) 10% represents national figure

(3) 10% represents national figure. 44% of TV households have been passed by broadband cable.

(4) 12% represents national figure. 50% of TV households have been passed by broadband cable

(5) 13.5% reperesents national figure. 50%....

Source: Screen Digest

Sources:

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