Electricity Network Investment and Regulation for a Low Carbon Future

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ELECTRICITY NETWORK INVESTMENT AND REGULATION FOR A LOW CARBON FUTURE[1]

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Abstract

The requirement for significantly higher electricity network investment in the UK seems certain as the capacity of distributed generation and large scale renewables increases on the system. In this paper, which forms a chapter in the forthcoming Book "***Delivering a Low Carbon Electricity System: Technologies, Economics and Policy***"[2], the authors make a number of significant suggestions for improvement to the current system of network regulation. First, they suggest that the RPI-X system needs to be overhauled in favour of a simpler yardstick based system and which allows for more merchant transmission investments. Second, future regulation should involve more negotiated regulation involving agreements between network owners and purchasers of network services. This would be particularly advantageous for decisions on new network investments. Third, more extensive use needs to be made of locational pricing within the transmission and distribution system in order to facilitate the least cost expansion of low carbon generation, including micropower. Fourth, consideration needs to be given to ownership unbundling of distribution networks from retail supply. This would better facilitate the entry of distributed generation and the development of appropriate competition between grid and off-grid generation supply and demand side management. Finally, there needs to be a significant increase in R&D expenditure in electricity networks supported by customer levies.

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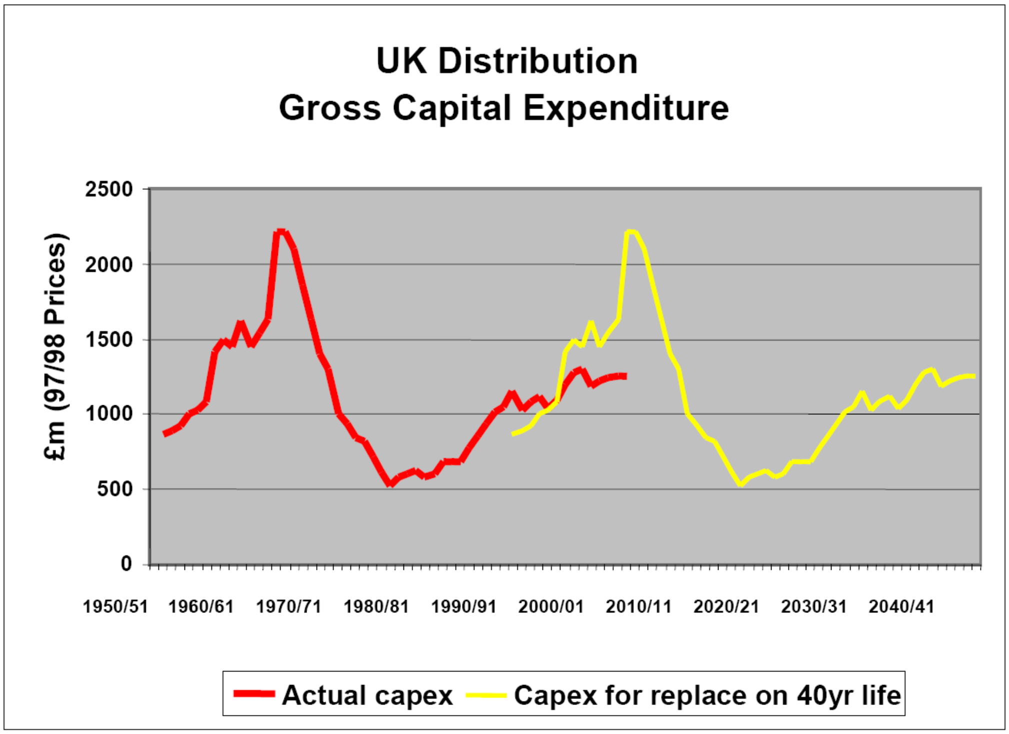
1. Introduction to the Regulation of Electricity Networks in the UK

Around 30% of the current price of electricity relates to electricity distribution and transmission charges. In England and Wales electricity transmission revenue in 2005-06 totalled £1.2bn (Ofgem, 2006) while distribution revenue was around £3.1bn (Ofgem, 2004a, p.6). These charges are regulated by the electricity regulator Ofgem. In Northern Ireland electricity transmission and distribution charges totalled around £0.2bn in 2005-06 (Viridian, 2006) and are regulated by the Northern Ireland Authority for Utility Regulation (NIAUR, formerly NIAER). There are 15 regulated distribution companies in the UK (though rather fewer independent owners) and three regulated transmission businesses in Great Britain (in Northern Ireland transmission and distribution are not separated out for regulation).

The introduction of large amounts of renewables (both large and small scale) and gas-fired microgeneration into the electricity system necessitates large amounts of new investment in these networks. Elders et al. (2006) identify the following technologies as being potentially important in future transmission and distribution networks: new power electronics, flexible AC transmission system (FACTS), storage facilities (such as compressed air energy storage – CAES - and flywheel) and superconducting lines. There may be expenditure on DC transmission cables which might be in the form of North-South undersea cables. Future networks will require more active management as the intermittency of renewable energy requires increased network management to mitigate some of the effects (see DTI, 2006, pp. 210-211). The uncertainty of the timing, volume and location of new renewables also makes planning of network development more difficult than in the past and has implications for regulation.

Apart from the need for network investment due to the uptake of renewables, new investment is needed due to the aging of the existing network. The current transmission and distribution network has been constructed mainly in the 1960's and 1970's and many plants are near their design life (usually about 40 years) - see Figure 1. The advent of more sophisticated asset management, condition monitoring and life extension techniques mean that the plant replacement can be delayed (i.e. the investment does not need to follow the lighter (yellow) line in Fig.1) and the investment peak of the 1960s is unlikely to be repeated. In that context it is important that the plant replacement is not like-for-like but the new plant enhances network security and maximises the uptake of renewables.

Figure 1: UK Distribution Gross Capital Expenditure
Source: Scottish Power



In the following sections we will discuss the present system of economic regulation of networks in the UK and how this may need to adapt in order to facilitate significant volumes of renewable energy sources to 2020 and beyond.

2. Transmission and Distribution Price Control Reviews

Currently transmission and distribution charges are reviewed every 5 years. The last review of distribution charges in Great Britain was in 2004 for the period April 2005 to March 2010. At the end of 2006 the review of transmission charges in Great Britain was completed for the period April 2007 to March 2012. In Northern Ireland transmission and distribution services are combined in one company. A review for the period April 2007 to March 2012 was completed in September 2006. These reviews determine the level of transmission and distribution charges. We briefly characterise the nature of these reviews.

Network price reviews follow a similar format (see Pollitt, 2005). Companies submit detailed business plans for the next five years including projections of operating and capital expenditures. Capital expenditure plans detail load and non-load related investments and make specific reference to proposed major projects. Ofgem/NIAUR review these plans and make initial proposals for price revisions according to the RPI-X formula proposed by Littlechild in 1983 and in use in telecoms, gas, airports, water as well as in electricity. The regulatory review consists of efficiency studies of operating costs. These are of two types: bottom up - consultant estimates of cost categories; and top down – using efficiency methodologies such as corrected ordinary least squares. Capital expenditure plans are assessed using engineering consultancy audits of capital expenditure plans. Companies can then respond to the proposals which are then revised (once or twice) until a final proposals document is published. This final proposals document can be appealed to the Competition Commission by one or more of the companies that it covers. The process of a price review takes around 18 months and is completed four to five months before the new prices are due to take effect.

The regulators are in a position where they decide what level of capital and operating expenditure is reasonable and also what the allowed rate of return should be on regulated assets. In distribution these three elements represent around one third each of the total regulated revenue. Table 1 gives the revenue detail for one of the distribution companies (United Utilities) in the recent distribution price control review. The company receives discounted revenue (line 26) equal to the discounted value of its allowed costs (line 19) which include the five year movement in its discounted regulatory asset value (line 6). The discount rate is the weighted average cost of capital allowed by the regulator and the discounting ensures that the company earns this return. Table 2 gives the revenue detail for National Grid Electricity Transmission (the largest transmission company in the UK) from the initial proposals from the ongoing transmission price control review. The company receives discounted revenue (line 19) equal to the discounted value of its allowed costs (line 14). This discounted cost includes the five year movement in its net present value of regulated assets (line 6) and hence compensates the company for changes in its regulatory asset base.

Table 1 Regulated revenue for a typical electricity distribution utility
(Source: Ofgem, 2004a, p.127)

		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
	PRICE CONTROL CALCULATIONS FOR UNITED UTILITIES						
	2002/03 Prices						
		£m	£m	£m	£m	£m	£m
	RAV						
1	Opening asset value		920	964.3	1,002.50	1,034.70	1,060.80
2	Total capex		112.7	112.3	111.8	111.4	110.9
3	Depreciation		-68.5	-74.1	-79.7	85.3	-90.9
4	Closing asset value		964.3	1002.5	1034.7	1060.8	1080.9
5	Present value of opening / closing		920				825.2
6	Year movement in closing RAV						94.8
	ALLOWED ITEMS						
7	Operating costs (excluding pensions)		67	64.7	63.1	61.7	60.2
8	Capital expenditure (excluding pensions)		103.5	103.1	102.6	102.2	101.7
9	Pensions allowance		16	16	16	16	16
10	Tax allowance		19.4	22	23.1	24.5	24.5
11	Capex incentive scheme		1.8	1	-0.6	-1.1	-0.5
12	Sliding scale additional income		1.6	1.7	1.8	1.8	1.9
13	Opex incentive / Other adjustments		1.4	1.4	1.4		
14	Quality reward						
15	DPCR3 costs		1.5				
16	Total allowed items		212.3	209.9	207.5	205.1	203.8
17	Present value of allowed items		206.6	193.6	181.3	169.8	159.9
18	5 Year movement in closing RAV						
19	TOTAL PRESENT VALUE OVER 5 YEARS						1006.1
	REVENUE						
20	Revenue index		1	1.011	1.013	1.022	1.024
21	Discounted revenue index		0.973	0.932	0.885	0.846	0.803
22	Price control revenue	205.2	220.9	223.2	223.7	225.8	226.1
23	Excluded services revenue		5.8	5.8	5.8	5.8	5.8
24	Total revenue		226.7	229	229.5	231.6	231.9
25	Present value of total revenue		220.6	211.2	200.6	191.7	181.9
26	TOTAL PRESENT VALUE OVER 5 YEARS						1006.1
27	P0 based on the above Revenue (line 22)		7.6%				
28	P0 for Innovation Funding Incentive (IFI)		0.4%				
29	29						
30	Total P0 for comparison purposes		8.0%				
31	X		0.0%				
	Analysis of PO (%):						
32	Include EHV	1.5%					
33	Exclude metering	-1.3%					
34	Change in Opex	-7.0%					
35	Depreciation	7.8%					
36	Return	2.7%					
37	Rates	1.0%					
38	Tax	5.0%					
39	Other	-1.6%					
40	Total	8.0%					

Table 2: Regulated Revenue for National Grid Electricity
(Source: Ofgem, 2006a, p.95)

All prices are £m in 2004/05 terms

	Licensee = NGET TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		5,415.6	5,634.2	5,761.3	5,931.6	6,187.4
2	Total capital expenditure		601.3	524.9	581.1	655.6	677.9
3	Depreciation		-382.7	-397.8	-410.9	-399.8	-416.1
4	Closing asset value		5,634.2	5,761.3	5,931.6	6,187.4	6,449.2
5	Present value of opening/closing RAV		5,415.6				5,041.1
6	5 year movement in PV of RAV						374.5
	Allowed items						
7	Operating costs (excluding pensions)		266.0	259.7	254.3	254.0	254.9
8	Capital expenditure		601.3	524.9	581.1	655.6	677.9
9	Pensions allowance		38.5	37.8	37.4	37.3	36.9
10	Tax allowance		101.1	105.6	110.4	110.2	108.1
11	Total of allowed items		1,006.9	928.1	983.2	1,057.1	1,077.7
12	Present value of allowed items		982.4	861.9	869.3	889.7	863.4
13	5 year movement in PV of RAV						374.5
14	Total present value over 5 years						4,841.3
	Revenue						
15	Revenue index		1.000	1.020	1.040	1.061	1.082
16	Discounted revenue index		0.976	0.947	0.920	0.893	0.867
17	**Base price control revenue**	**924.9**	**985.5**	**1,005.2**	**1,025.3**	**1,045.8**	**1,066.7**
18	Excluded service revenue	58.2	58.4	64.3	71.9	75.8	76.1
19	Total TO revenues	983.1	1,043.9	1,069.5	1,097.2	1,121.6	1,142.8
20	Present value of total revenue		1,018.5	993.3	970.0	943.9	915.6
21	Total present value over 5 years						4,841.3
22	IFI revenue forecast		3.9	4.0	4.1	4.2	4.3
23	Price control extension reconciliation		0.7	0.0	0.0	0.0	0.0
24	Total price control revenue		1,048.5	1,073.5	1,101.3	1,125.8	1,147.1

Higher volumes of renewables embedded within distribution networks (load related microgeneration and smaller scale projects) and directly connected to transmission networks is already impacting on economic regulation of networks. The distribution price control identified a total capital expenditure requirement from 2005-2010 of £5.7bn (an increase of 48% over the previous review period). This during a period when the total renewables share on the system was only expected to grow by around 5% of total electrical energy. The growth of capital expenditure in electricity transmission is expected to be more substantial growing by 125% over the previous price control period to £3.8bn over 2007-2012 (Ofgem, 2006a, p.9). The review also allows for adjustment mechanisms which allow for more (or less) capital investment should connected generation capacity be greater than the base line forecast (Ofgem, 2006a, b). In addition to this investment, an interim review had already allocated an additional £500m of investment specifically to allow for extra renewable generation on the system (Ofgem, 2004c). These are significant sums of money and include only the beginnings of increased network investments to support large percentages of renewables on the system. Future reviews, as our opening discussion makes clear, seem destined to involve much bigger increases on the 2005 figures. Clearly incentivising least cost network support for renewables is a major issue. As is coping with the uncertainty in the development of network requirements in the face of different electricity futures (see Elders et al. (2006) and Elders et al., this volume).

Minimising the cost of network expansion and upgrade is a major issue for the regulators. The distribution price control review introduced a sliding scale system for capital investment incentives. The incentives are outlined in Table 3. PB Power were the engineering consultants who reviewed the companies capital expenditure plans. The higher the ratio of company base expenditure selected to PB Power's assessment the weaker the incentive if the company actually delivered its investment below budget. Thus a company that selected as its base allowed revenue the lowest ratio of its cost to PB Power's estimate could keep 40% of any under-spend while the company that selected the highest ratio could only keep 20% of any under-spend. Thus a company who estimated that it needed to spend £140m when PB Power estimated only £100m was required would have a base target of £115m. If it actually achieved £100m it would receive £100m plus an incentive payment of £0.6m. By contrast a company that said it needed £100m against PB Power's £100m and then actually achieved £100m would receive a £100m plus an incentive payment of £4.5m. This is a menu of contracts approach[3] to regulation which encourages companies to more correctly reveal the true estimated cost of capital investments. The transmission price control review has just implemented that a similar scheme for its 2007-2012 control period (Ofgem, 2006a, pp.96-106).

Table 3: Distribution price control capital expenditure incentive scheme
Source: Ofgem (2004a, p.87)

DNO:PB Power Ratio	100	105	110	115	120	125	130	135	140
Efficiency Incentive	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	2.5	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
as pre-tax rate of return	0.200%	0.168%	0.130%	0.090%	0.046%	-0.004%	-0.062%	-0.124%	-0.192%
Rewards & Penalties									
Allowed expenditure	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual Exp									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

3. The regulation of congestion, losses, quality of supply, visual amenity and noise

Other aspects of economic regulation are also important as we will discuss below.

[3] See Baron (1989).

Transmission costs have two components: fixed and variable. The fixed component relates to the cost of the existing capacity of the grid. As most of the cost of the grid relates to sunk investments, the charges for access to it are also fixed and usually they are per capacity (i.e. per kW). In the UK, they are termed Transmission (or Distribution) Network Use of System charges. If a new generator wants to connect, then it has to pay additionally a one-off connection charge which covers the cost of equipment used to connect the generator to the grid.

Actual transmission and distribution charges vary somewhat by location, load and type. They are paid by generators and suppliers. For suppliers, they are usually based on the MW load of the user during the system peak demand (so called triad charges), For generators, they are based on the declared net capacity of a plant. Distribution (DNUoS) charges vary by company area, while there are up to 21 transmission charging zones (different for demand and generation) in Great Britain. The Transmission Network Use of System (TNUoS) charges are levied per kW of capacity according to the imposed value to the system of generation/demand in those areas. Figure 2 shows the generation zones and charges in 2005/6. These charges reflect the marginal increase in network flows caused by an increase of generation/demand at a particular node by 1 MW. They are expressed in MW*km, i.e. they reflect the increase in a flow on a line multiplied by the length of the line. The marginal MW*km increases are multiplied by a notional cost of a particular line (the so-called expansion constant different for different types of lines and rated voltages) and summed over all the lines. Due to the predominant north-south flows in GB, generation in the South East receives a rebate, as it causes counterflows, i.e. the calculated marginal flows tend to be against the actual network flows. For example a typical 1 GW plant located in zone 21 (Peninsula) would receive a rebate of £8 million a year. On the other hand generation in the North and Scotland pays extra (see National Grid, 2006, p.4) as the calculated marginal flows reinforce the actual network flows. Thus a similar 1 GW power plant located in zone 2 (North Scotland) would have to pay £21 million a year. The supplier charges are designed such that there are no negative charges for suppliers (demand) as that would create perverse incentives to increase demand during system peak (triad charges).

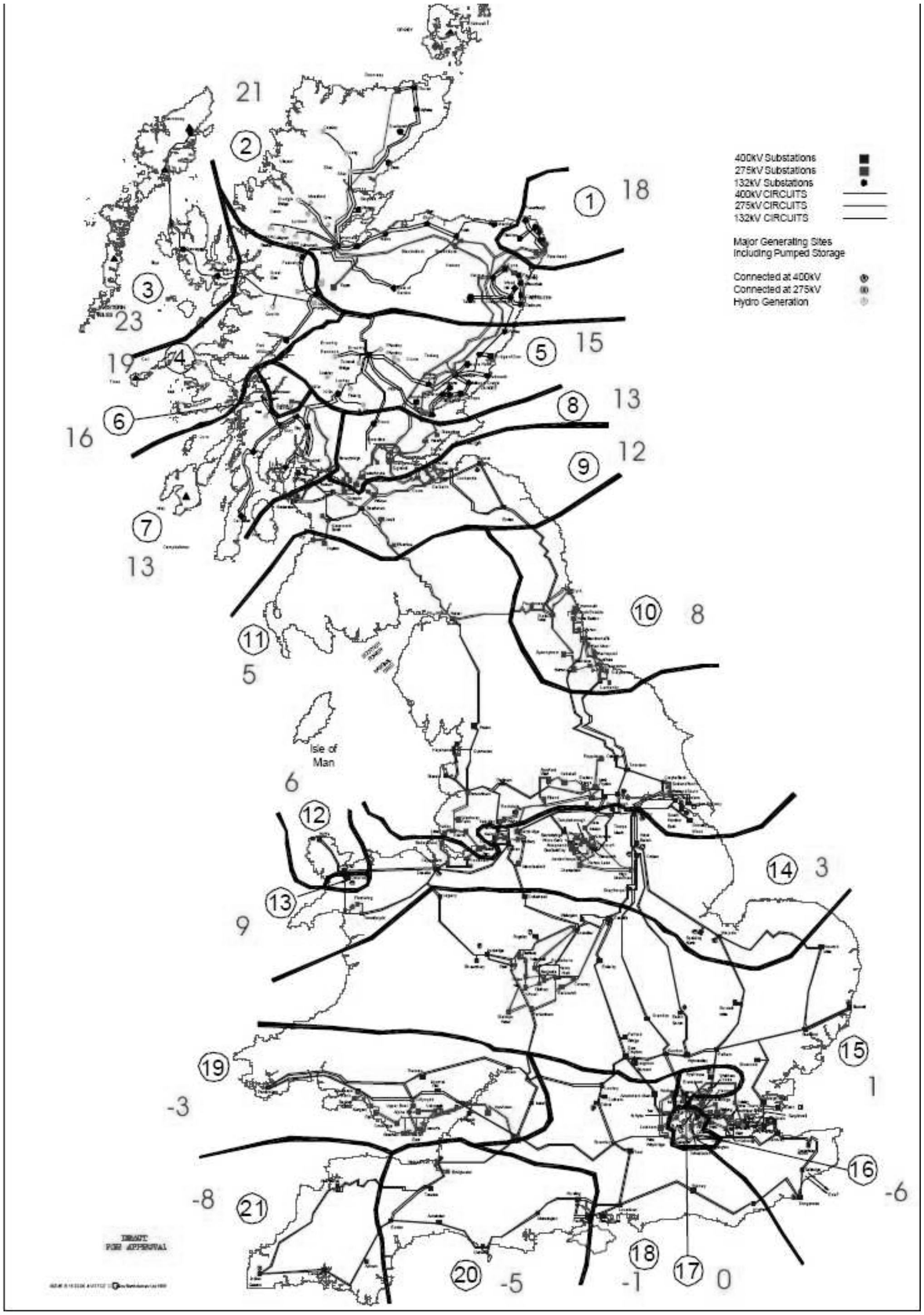


Figure 2: Transmission Network Use of System (TNUoS) zones and charges in GB in 2005/6. Note: zone numbers are circled, TNUoS charges in £/kW are the non-circled numbers.
Source: National Grid (2005) *The Statement of Use of System Charges Effective from 01 April 2005,* London: National Grid

It is recognised that high TNUoS charges could have a detrimental effect on renewable development in North of Scotland, where a considerable renewable resource (wind and marine) is located (see chapters by Jamasb, Maratou et al. and by Cust et al.). Consequently there are proposals (in mid 2006) for for the Secretary of State to apply a dispensation in TNUoS charges 'in a single area of high renewable energy potential' for up to ten years. Such dispensation is undesirable in that it may encourage the location of generation in Scotland which imposes inefficiently high costs on the system as a whole. However the subsequent analysis performed for the Department of Trade and Industry (Bialek et al, 2006) showed that introduction of a dispensation would not have a significant effect on reaching the Government's 2010 target. The main reason for that is that any shortfall in meeting the target would be mitigated by an increase in Renewable Obligation Certificate (ROC) price. Moreover, North of Scotland enjoys a competitive advantage (even after inclusion of comparatively high TNUoS charges) over any other renewable technology with a significant remaining resource. At the time of writing (2006) no dispensation from high TNUoS charges has been applied.

Distribution charging follows a different pattern. Until recently, a renewable generator wishing to connect had to pay the 'deep connection' charge, i.e. the full cost of the necessary distribution network reinforcement. From 1 April 2005, a new electricity distribution charging framework came into force in the UK featuring a common connection charging boundary for demand and generation, the replacement of deep connection charging with a 'shallowish' charge, and the introduction of generator distribution use of system tariffs (GDUoS) to supplement the costs that are not being able to be recovered due to removal of the deep connection charge. The second party connecting to the distribution network within the first five years has to pay a proportion of reinforcement cost. Ofgem is currently (2006) working on further development of GDUoS charges. [4] The objectives are cost-reflectivity, facilitation of competition, predictability, simplicity and transparency. There are obvious tensions between some of these principles.

The variable transmission costs are the cost of transmission losses and congestion costs. Congestion costs are incurred when there is not enough transmission capacity in the system. In the UK, congestion usually occurs on the interconnector between Scotland and England. If that happens, the System Operator (National Grid) has to constrain-off a cheaper generation in Scotland and to constrain-on a more expensive generation in England. Congestion costs are currently recovered uniformly, i.e. non-locationally, from all the generators through Balancing Services Use of System (BSUoS) charges. BSUoS are uniform, i.e. everyone pays the same per MWh. TNUoS charges are not directly related to congestion although, as expected, there is correlation between the two due to North-south pattern of flows The reason for uniform, rather than more complicated locational charging for congestion (such as the nodal pricing, practiced in

[4] See http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges/edc2

the PJM market in the US) is that congestion costs are currently relatively small and would not warrant an expensive set up and run pricing mechanism.

Power losses are proportionally to approximately square of a power flow in a line. Distribution losses consume about 6% of energy produced while transmission losses consume about 2% (Ofgem website). There are additional incentive schemes to reduce distribution network electrical losses through price review controls. In 2006 transmission losses are still paid for uniformly by all the users (generators and suppliers) despite numerous attempts to introduce locational charging for losses. Depending on the marginal generation connected to the system reducing these losses could reduce emissions more or less proportionately to the energy saved. Analysis of a recent proposal for locational (zonal) charging for losses has shown that the energy loss savings from the scheme would be small, in the range of a few percent of the losses incurred, while monetary transfers between generators and suppliers would be more than an order of magnitude higher (see Bialek et al, 2004). If marginal charging for transmission losses was introduced, generators in the north and suppliers in the south would pay more while generators in the south and suppliers in the north would pay less for transmission losses. Some generators in the south would even receive a rebate. Thus the overall pattern of charges would be to some extent similar to TNUoS charges.

There are also incentives to improve network reliability in transmission and to reduce customer interruptions and minutes lost in distribution. In distribution companies can be exposed to revenue adjustments of +/- 2% of review for over / under performance against targets on reliability and quality of supply (see Giannakis et al., 2005). There are also visual amenity and noise impacts of transformer substations and of overhead wires (see Ofgem, 2006).

Ofgem has recently experimented with willingness to pay surveys to establish whether companies should be allowed to recover more revenue in order to reduce the local environmental impact of electricity assets. More renewables create local amenity impacts within the distribution network or create the need for greater transmission capacity requirements to support long distance power flows (particularly from Scotland to the South East). Household electricity meters currently form part of the regulatory asset base of distribution companies (though this was set to end in April 2007) and hence decisions about smart metering still need to be taken by Ofgem/NIAUR. Patrick and Hannah Devine Wright discuss this in their chapter.

4. Improvements to the current system of economic regulation

A key challenge for network regulation is that incentivising efficient investment in situations of uncertainty about the nature of demand growth is not very well understood. Network charges have fallen in real terms substantially since privatisation (by around 50% in distribution and 30% in transmission per unit of electricity). This has been the result of the strong incentive properties of the RPI-X system of regulation combined with pressure to reduce costs and prices via significantly positive values of X. However network charges are now beginning to be driven by investment requirements. Over 2005-2010 continuing operating efficiency improvements did not fully cancel out the requirement for higher investment in electricity distribution while the transmission review for 2007-2012 also involves significant price rises due to the substantial rise in capital investment. This has already led to calls for the system of regulation to reviewed and reformed (see Pollitt, 2005). As the rest of this book suggests there are ways that we can incentivise efficient investment in low carbon generation which do provide incentives for this to be added at least cost. However network investment in the UK is still largely driven by a central planning type of system.

The requirement for large and increasing amounts of regulated investment in networks driven by uncertain renewables requires regulators to consider carefully the design of economic regulation and whether the current system is fit for purpose.

We want to suggest five areas which Ofgem needs to consider in future. First, the current approach to RPI-X regulation needs to be updated. Second, the regulation of new investment needs to draw on emerging ideas for ‘constructive’ user engagement from other regulated sectors and other countries and incorporating more use of competitive tendering of network investments. Third, the issue of locational pricing signals both in transmission and distribution charges drawing on nodal pricing concepts in use in the PJM market in the US is examined. Fourth, unbundling of networks from retailing - as has happened in transmission - could be extended to distribution. Fifth, innovation in networks needs to be encouraged as is beginning to happen in distribution with the introduction of the Innovation Funding Incentive (IFI) and is proposed for transmission.

4.1 Overhaul of RPI-X

The current system of price reviews makes a clear separation of the analysis of operating and capital efficiency. This made sense when companies had very similar mixes of capital and operating efficiency or where separability of capital and operating expenditure can be assumed. However, it has always been methodologically suspect (see Pollitt, 2005). In addition loss incentive reduction schemes and quality of supply incentive schemes have been added on to the basic analysis of cost efficiency rather than incorporated in it. As Giannakis et al. (2005) have shown this can lead to perverse results for operating efficiency analysis.

Rapid divergence in technology and investment between distribution company regions, caused by the increase of renewables, makes the current approaches to economic regulation increasingly open to challenge as they have little underlying theoretical validity. Operating and capital expenditure trade-offs need to be encouraged especially where extra operating expenditure can avoid large new capital investments and reduce total costs. Similarly projects which significantly reduce operating expenditure for modest increases in capital cost need to be properly encouraged.

There is also the issue of proper risk allocation between customers and companies. RPI-X has the effect of reducing some of the risks on the customer (such as cost risk) but its actual operation through submitted business plans and regular revisions shifts much investment risk on to the customer. Proper risk allocation should occur. More explicit risk sharing needs to be considered such as occurs in US performance based rate schemes (PBR) where companies share risk around a central target rate of return (see Joskow, 2005).

Other areas for attention are the length of the current review period. Longer review periods (7-10 years) would create a more stable environment for investment and innovation. Consideration should also be given to the ending of company specific X factors based on detailed comparison of own costs against other companies in a UK sample. This can lead to gaming between companies (Jamasb, Nillesen and Pollitt, 2004). A simpler ‘yardstick’ system based on average costs in the sector may yield better incentive properties and remains to be fully investigated (see Shleifer, 1985, and Pollitt, 2005). These changes would be particularly useful for determining the revenue related to past investment.

Both DNOs and National Grid have monopolies over the commissioning and operating of new distribution and transmission links. The system of regulation guarantees them a fair rate of return on approved investments delivered to budget. Merchant (or competitive) transmission for some major upgrades may be an option and the regulator should undertake a careful cost-benefit analysis of this if it is proposed. However most scenarios imagine that such entirely new and potentially competitive capacity is rare (see Elders et al., 2006). However it is possible that distinctly new links such as North-South DC cables could be proposed and built by third parties. Some links to Scottish Islands, the Netherlands and offshore generation may be built under this type of arrangement.

4.2 'Constructive Engagement'

Regulated network investments occur because of the absence of a competitive market for network services. However there have been important developments in the creation of negotiated solutions to investments between buyers and sellers of network services. The most exciting development in the UK is that occurring in airport regulation. Airports exist in a rapidly expanding market, require substantial new investment and are subject to significant demand uncertainty. BAA owns and operates London's Heathrow, Gatwick and Stansted Airports. These airports are regulated by the Civil Aviation Authority (CAA) which recommend prices following price reviews to the Competition Commission. Following widespread criticism of the last price review the CAA is pursuing a new approach to deciding its recommended charges (see CAA, 2004). This involves the CAA chairing negotiations between BAA and the airline users at each of the three London Airports in order to negotiate a Price Control Business Plan (see CAA, 2005). This plan incorporates agreed investments to meet agreed growth targets and has the advantage of taking the regulator out of the process of deciding the appropriateness of investments. The CAA still has to approve the plan and continue to provide efficiency and other studies to inform the negotiations.

Such a plan to involve the users in determining how and when regulated investments should occur has been implemented for electricity transmission and sub-transmission in Argentina. Littlechild and Skerk (2004a, b) discuss the 'public contest method' for determining new transmission investments. This method involved users voting on new investment proposals. If 30% of the beneficiaries of an investment voted against it, it would not go ahead. If 30% of the beneficiaries voted in favour of a project and less than 30% against, it would be tendered and the cost shared out in proportion to the benefits (subject to a test that the system benefits exceeded the cost). Littlechild and Skerk find that this method was successfully adopted for a significant number of projects and that a controversial fourth transmission line into Buenos Aires was correctly delayed by this process. They also highlight that the compulsory competitive tendering of the project and the use of the winning tender price in subsequent adjustments to the regulatory asset base of the transmission company lead to multiple bidders and very competitive winning bids. Littlechild and Ponzano (2006) detail a related user engagement process in Buenos Aires province (the area around the city) which led to the successful negotiation of a 10-year transmission plan (to run from 1999) between the transmission company and more than local distribution companies. This paper strongly suggests the practicality of buyer-seller negotiations for the deciding of small investments (as part of larger package).

Given the small number of retailers, distributors and transmission companies in the UK such negotiated solutions to deciding transmission investments needs to be considered seriously. The

UK needs to move away from central planning of such investments and the control of longer range planning of the system by National Grid (who effectively control it in Great Britain). Serious consideration needs to be given to the competitive tendering of transmission and large distribution investments wherever possible as this makes regulation easier. Both of these suggestions would greatly extend the role of the market in network investments.

4.3 Locational Pricing

Generation and load investments impose different costs according to where exactly they occur in the electricity system. Locational price signals received by generation and loads should reflect this. In the UK these locational signals are received through locationally differentiated transmission and distribution access charges. However, such signals can be provided via an independent system (or market) operator and be decoupled from charges imposed by transmission and distribution companies. The issue is whether there is sufficient geographical variation in the current charging systems to provide efficient market signals for the location of renewables and fossil micro-generation. In transmission there is a zonal system for TNUoS charges by kW (not kWh) with 21 zones in Great Britain. Within distribution networks there is currently no geographical differentiation of charges. A number of authors have argued for the superiority of a full nodal pricing system in the transmission system (e.g. Hogan, 1998). Under this system, widely referred to as Locational Marginal Pricing (LMP), charges for congestion and losses (as opposed to for capacity) are embedded within energy prices (per kWh) that vary at every significant node in the system. As noted above no such charging exists in the UK. The best example of this in practice is the Pennsylvania-New Jersey-Maryland (PJM) market in the US (now expanded to cover several other states). This market is the largest interconnected wholesale market in the world with around 164 GW of capacity by mid-2005. There are 3000+ nodes in the system. These provide clear signals for new connection and avoid the averaging problem which exists in a zonal system. In PJM energy prices are recalculated every 5 minutes from bids supplied by generators/suppliers. Nodal price differentials recover around 20% of the costs of transmission within PJM. Implementing a full PJM type system would be very expensive and disruptive to the current system; however a centrally administered system of LMP could be administered by the system operator (National Grid) who could calculate nodal energy prices from bids submitted to the current Balancing Market.

The current UK system of limited zonal pricing involves averaging of capacity charges across zones and no locational variation in energy related charges. This may be important in the context of renewables where there are a number of sites where they can be built which may impose very different local power flows and require different pattern of system upgrades. Averaging was attractive in the early years of deregulation when there was a desire to improve competition and liquidity in the wholesale energy market by having a single energy price across the country. However as energy markets build experience and market participants become better informed this argument loses force. In contrast to the current situation where nodal marginal transmission losses do not vary much around the network (Bialek et al, 2004), they may be higher in the future. In addition some evidence shows that nodal pricing may actually mitigate market power relative to a zonal system (see Green, 2004) by magnifying the local demand response and hence making it less profitable. Other significant markets are moving towards nodal pricing including the significant Texas market which is the closest in terms of overall liberalisation to the UK globally (see Adib and Zarnikau, 2006). New Zealand is another market with significant experience of successful nodal pricing (see Bertram, 2006).

LMP or nodal pricing requires a detailed model of the system that it is applied to, capable of calculating the real time locational prices. This model has to be commissioned and maintained by the system operator. It can be a non-trivial exercise and may have significant ongoing costs (high in PJM, low in New Zealand). Implementing such a system in the UK would require a major change and would be contentious. Any implementation scheme would need to be carefully evaluated. The UK currently enjoys a system which has low congestion costs relative to other systems (such as PJM). However, the most advanced electricity markets are moving in this direction and large changes to the power flows in the network, coupled with the significant costs of upgrading individual lines, may make nodal pricing a sensible option.

Locational pricing is well understood in the context of transmission. However in the context of distribution systems it may be just as important. Small-scale renewables connect directly to the distribution grid but may also be of more benefit or more cost in particular places. Jamasb et al. (2005) propose that the UK should implement a form of locationally differentiated pricing within distribution networks as this would properly signal the best places to build new capacity, especially at the ends of constrained distribution networks. It would be necessary to build detailed models to calculate location varying prices but the benefits would seem to outweigh the costs of doing this. At the level of distribution networks zonal differentiation of Distribution Use of System charges may be a reasonable initial step which captures much of the benefit of locational signalling. Locational pricing within the distribution network might (in the future) facilitate the efficient connection of micro-generation and incentivise the installation of smart meters and automatic appliance control and battery equipment at the household level.

More finely differentiated locational prices serve the additional purpose of giving clear information to the regulator and to the users of the system as to the value of new transmission and distribution capacity and form the basis of evaluating where lifting constraints would be worthwhile. They can also be used to collect some revenue which can be applied to finance new investments. In the past large-scale generation investments, slow demand growth and more predictability in the development of the system over the next price control period made the lack of locational pricing signals a minor problem for the UK system. However, more disparate generation and demand growth makes getting locational signals right increasingly important. Any change would require careful cost-benefit analysis and attention would need to examine the relative costs and benefits of alternative systems, some of which might offer less accurate price signals but be cheaper to implement.

4.4 Ownership Unbundling

England and Wales provided the world's best example of effective unbundling of electricity transmission from the rest of the electricity system (see Jamasb and Pollitt, 2005, for a discussion of this in a European context). The creation of a separately owned National Grid company responsible for transmission and unable to invest in other parts of the electricity sector facilitated the development of a competitive generation market. This development occurred free from the discriminatory access to transmission problems that has plagued other markets which did not follow the UK model (in particular Germany). The regulation of the National Grid was made easier because it was a separate company and its regulated charges came down substantially as efficiency improved (see Newbery and Pollitt, 1997).

The experience in Scotland was rather different. Scottish Power and Scottish Hydro-Electric were privatised as bundled companies consisting of generation, transmission, distribution and retail assets. In 1991 residential prices were lower in Scotland than in England and Wales but now they are higher. An important explanation of this appears to be the failure to separate out the transmission function into a separately owned company (see Pollitt, 1999). This problem was recognised with the recent creation of an all GB transmission system under the control of National Grid. Although Scottish Power and Scottish Hydro still own the transmission assets they are now independently operated by National Grid as the single GB wide system operator. The result of this change appears to have been a relative lowering of prices in Scotland.[5]

The arguments for clear separation of transmission from the rest of the electricity system are based on the theory of vertical integration (see Tirole, 1988). Monopoly parts of the supply chain have an incentive to 'foreclose' on competitors by imposing unreasonable access conditions in related parts of the supply chain in favour of their own divisions in order to drive up margins in

[5] Source: David Halldearn (Ofgem) speech on 'British Electricity Trading and Transmission Arrangements' June 15, 2006 available at http://www.iet.tv/technology/power/index.html?page=4

the competitive parts of the business. This is practically possible in electricity transmission as a monopoly transmission company controls the connection and dispatch of individual plants, and can be done by increasing connection costs or imposing expensive rules for dispatch on competitors' power plants. Distribution systems in the UK have traditionally been less prone to such foreclosure because they are passive rather than active networks. Tough non-discriminatory regulation and an initial lack of own generation seems to have been effective in preventing the exercise of serious market power in either generation or supply foreclosure. However increases in embedded renewables mean that the distribution network is set to change to become more like a transmission network: actively managed two way power flows with the potential for own generation projects to be favoured over rivals' projects.

Such transmission and distribution convergence (particularly at higher voltage levels in the distribution system) may mean that consideration should be given to ownership unbundling between distribution and the rest of the electricity system (i.e. retail (supply) and generation). This would have the additional advantage of encouraging competition between on and off grid electricity supply as retailers would be separated completely from distribution owners and reduce the incentive to favour on-grid solutions. This was a scenario envisaged by Walt Patterson in his book *Transforming Electricity: The Coming Generation of Change* (1999). Such unbundling would eliminate the competitive advantage that DNOs currently have over other companies in locating distributed generation within their networks. One effect of such unbundling might be to increase the value of nodal pricing in distribution as small scale generation could not be added by the distribution company with superior grid information but only in response to clear non-discriminatory price signals. Arguments in favour of this would be strengthened by evidence that retail competition might be promoted by the separation of retailers from distribution. The evidence for this is limited in the UK but it is the case that switching rates to non-former incumbents are highest in the regions where the former incumbent suppliers are not integrated with distribution (see Ofgem, 2006c)[6].

4.5 Innovation and RD&D Expenditure

The high level of investment expenditure in networks required to support large scale deployment of low carbon technologies suggests that there is scope for significant technological progress in network technologies. However RD&D expenditure continues to be very low in the UK electricity sector, suggesting limited scope for new innovation in the sector.

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[6] The five non-integrated regions - Swalec, SWEB, Northern, Norweb and Yorkshire - have a weighted average switching rate of 48.7% against 43.5% for the other 9 regions of GB in March 2006.

Jamasb and Pollitt (2005) note the collapse in UK energy RD&D following the liberalisation of the electricity sector and this also the theme of chapter 3 of this volume. By 2004 the amount of money spent by UK network companies on RD&D was very small (less than £4m p.a. or less than 0.1% of revenue, see Ofgem, 2003, p.8). The public good aspect of RD&D is significant both in generation and in networks given the large number of distribution and transmission companies in the UK and globally. RD&D activity also lacks critical mass (with no company having any significant in house capability) and is not a strategic priority given the short term and regulated nature of expenditure and profitability.

Ofgem have recently explicitly recognised this with the introduction of an innovation funding incentive (IFI) (see Ofgem, 2004b). This scheme allows distributors to raise prices by up to 0.5% of revenue to fund research projects aimed at improving distribution network performance. The recent transmission price control review has extended this to transmission charges (Ofgem, 2006a, p.66-67). The sums of money involved are small (in total for distribution and transmission they would be less than £25m p.a.) but they may be significant in improving the rate of technical progress in UK networks at a time when capital expenditure is increasing significantly. Mott Macdonald BPI (2004) estimated benefits of the distribution IFI with a net present value of £386m on consumer expenditure of £57m.

5. Conclusions

Electricity transmission and distribution networks are a significant part of the total cost of electricity supply in the UK. Large amounts of low carbon generation, particularly renewables, will necessitate increased and currently uncertain investment in electricity networks. This is already beginning to occur in the latest transmission and distribution price control reviews. Although the system of network regulation to 2006 has successfully delivered more investment with lower prices, it is not clear that the current system of regulation is fit for purpose in a low carbon electricity system.

The importance of electricity infrastructure investment is recognised in the Stern Review (Stern, 2007). The Review recognises that electricity infrastructure services ‘would change… fundamentally’ (p.257). with a significant increase in low carbon technologies – such as small scale distributed generation and CHP - in the electricity system. The Review calls on regulators to ‘innovate in response to the challenge of integrating these technologies to exploit their potential, and unlock the resultant opportunities that arise from shifting the generation mix away from centralised sources.’ (p.421). The Review is necessarily silent on the details of what such a response might consist of, however this chapter is an attempt to suggest some of the innovations in regulation that may be necessary.

We have recommended a review of the current practice of RPI-X setting. We suggest new thinking in the determination and regulation of required network investments, particularly the use of user engagement and competitive tendering. Consideration needs to be given to the locational signals inherent in current transmission and distribution pricing structures and whether these need to be changed. Ownership unbundling of distribution from the rest of electricity system is an issue whose time will come and more thought must be given to the funding of increased R+DD in networks given the increasing amounts of capital expenditure involved.

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