

# Irish Energy Policy: An Analysis of Current Issues

John FitzGerald, Laura Malaguzzi Valeri  
(Editors)

RESEARCH SERIES  
NUMBER 37

*October 2014*





# **Irish Energy Policy: An Analysis of Current Issues**

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**RESEARCH SERIES**

**NUMBER 37**

***October 2014***

Available to download from [www.esri.ie](http://www.esri.ie)

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Whitaker Square, Sir John Rogerson's Quay, Dublin 2

ISBN 978 0 7070 0 372 6

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The paper has been accepted for publication by the Institute, which does not itself take institutional policy positions. ESRI Research Series Reports are peer reviewed by ESRI research colleagues. The authors are solely responsible for the content and the views expressed.

## Acknowledgements

Funding from the ESRI Energy Policy Research Centre is gratefully acknowledged. This paper has benefited greatly from the support and advice of the Energy Institute, colleagues in the Economic and Social Research Institute (ESRI), the Department of Communications Energy and Natural Resources and other members of the Energy Policy Research Centre.



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## Executive Summary

The traditional goals of energy policy are to maintain a secure energy supply and to deliver the required energy at a minimum cost to consumers. In many developed countries, and in the European Union (EU) in particular, there is a third prominent goal: tackling climate change. In this paper we address a fourth challenge which is too often neglected in the formulation of energy policy – its distributional impact. The distributional effects are ignored in spite of their importance: energy policy can have a major effect in redistributing income between countries; between consumers and producers and between rich and poor households.

Many of the climate policies that influence Ireland are agreed at the EU level. Ireland has a role to play in helping to improve EU policymaking on climate change, for example by arguing for price instruments, which are more efficient, effective and transparent in achieving the goals of policy. If quantity based targets are to continue as the mainstay of climate and energy policy at an EU level, there must be safeguards put in place to ensure that they do not result in major transfers of wealth between EU members at a future date and that they do not unnecessarily increase the overall cost of climate action. For example, if Ireland is given an unrealistic target for emissions reduction, it could require actions that are either much more or much less expensive than for other EU countries, implying major transfers between Ireland and the rest of the EU at a future date. EU policy should ensure that there are appropriate mechanisms to prevent such possibly unpleasant surprises in the future.

In addition, where quotas are used as an EU policy instrument, they should always be auctioned to ensure that there are no windfall gains for producers, at the expense of consumers.

While Irish governments cannot influence policy in the UK, policy makers in Ireland must be cognisant of the lack of clarity about UK energy policy. Irish policy must also be formulated so as to be robust whatever the decision by the UK about its future EU membership.

This paper considers many facets of energy policy in Ireland. However, there are some areas of particular importance for the future welfare of citizens. One of the most pressing areas for policy is the development of the Single Electricity Market to conform to EU rules on trading electricity across countries. While there are gains to be obtained from such a reform that allows increased trading, research, described in this Paper, suggests that there is a risk that a new regime could

result in significantly higher prices for Irish consumers. This would be a very unsatisfactory outcome, with serious consequences for Irish competitiveness and living standards. Unfortunately, current research, while identifying weaknesses in the proposed reforms, does not give a clear guide as to how they can be improved. Under these circumstances the correct approach is to delay making a decision and, in conjunction with the EU, to seek to identify a more appropriate model that will be likely to benefit consumers in Ireland and elsewhere in the EU.

A major task for energy policy over the coming decade will be to deliver on the appropriate physical infrastructure to allow the objectives of Irish energy policy to be met.

- This task has an important financial dimension. Because of the large sums needed for the investment, policy needs to help ensure that the cost of the necessary finance is minimised. This means that policymakers should try to reduce any unnecessary uncertainty around such investment, especially with respect to the regulatory environment.
- There is also a major task for policymakers in ensuring an efficient planning process that helps to promote buy-in from all parties involved in the investment process. Further research into how best to accomplish this task is needed.
- Examples of key pieces of infrastructure that are important for Ireland's future development and that can reduce greenhouse gas emissions are: the North- South electricity interconnector; further interconnection between the Irish electricity system and the rest of Europe; bringing the Corrib gas field into production.

There are many opportunities to reduce energy use through increased energy efficiency. The first task is to ensure that economic incentives are appropriate to encourage an optimal level of investment. However, because of market failures, price signals on their own may not be sufficient to reach an appropriate level of investment. Instead policy needs to take account of lessons from behavioural economics to help households and companies find the right solution for their individual circumstances.

Experience elsewhere suggests that bad investment decisions can be made where new technologies are moved from the research phase to the development phase before they are fully developed. This can see countries locking into new technology at much too high a price. The extensive deployment of onshore wind in Ireland has taken place after a major fall in the cost of the technology. If major investment had taken place prematurely in the 1990s Ireland would have been saddled with a very high cost base. This lesson must be taken on board when considering the deployment of other new technologies, such as offshore wind and wave power. Until their costs have fallen to make them competitive, they

should remain in the domain of research and that research should be funded by the taxpayer rather than by energy consumers.

Finally, job creation is not, and should not be, the objective of energy policy. Instead the objective should be to deliver a secure and environmentally friendly energy supply to Irish consumers at a minimum cost. Naturally, the energy sector will be a significant employer for the foreseeable future, but the task of tackling Ireland's unemployment problem should be left to macroeconomic and industrial policy.



# Chapter 1

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## Introduction

This paper considers a number of challenges facing Ireland in the field of energy over the coming decade. It addresses some important questions where research evidence is available to provide guidance on the optimal policy response. It is not intended to be comprehensive so some important topics on which research evidence is lacking are not dealt with in detail. This paper follows a series of earlier papers on energy policy,<sup>1</sup> amplifying or amending the conclusions of these papers, where appropriate, and focusing on some of the more recent policy challenges where we have new and relevant evidence from research.

In evaluating the different challenges for policy the main criteria we consider are: how efficient will the policy be at achieving its objectives – will it minimise long-term costs for the economy, especially for consumers; how will the policy contribute to energy security, which is vital for the welfare of everyone in Ireland; how will it contribute to the objective of reducing greenhouse gas emissions; what will the distributional effects of the policy be?<sup>2</sup>

The first three of these objectives – cost effectiveness, security and reducing greenhouse gas emissions have underpinned Irish energy policy over the last twenty years. Consumers, whether households or businesses, are faced every day with the cost of energy and, as a result, have a clear focus on the objectives of minimising cost. This paper discusses the evidence on the successes and failures of policymaking in addressing this issue. In considering the ongoing cost of energy, attention has also to be given to Ireland's special circumstances and to the special circumstances that make energy markets different from many other markets (such as the markets for cars or for food).<sup>3</sup>

The second objective, energy security, may often be ignored by the wider public but it is crucial to the well-being of the population. Because of the success of past policy in Ireland and in the EU in ensuring the security of Irish energy supply in

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<sup>1</sup> FitzGerald and McCoy (1993), FitzGerald and Johnston (1995), FitzGerald *et al.* (2005) and FitzGerald (2011).

<sup>2</sup> The Department of Communications Energy and Natural Resources on their web site spell out the three key objectives for the energy sector as: to develop a competitive energy supply industry; to ensure security and reliability of energy supply; to develop energy conservation and end-use efficiency (<http://www.dcenr.gov.ie/Energy/>).

<sup>3</sup> A key factor making gas and electricity markets different from other markets is the scale of the necessary investment in networks (of pipeline and wires) required to deliver the energy to consumers.

recent decades, the issue of security may not attract adequate attention. It is only if energy is not available that the wider public becomes aware of a failure, often too late to do anything about it. The task of policymakers is to reflect the wider public interest by taking appropriate measures to ensure future security, even if they add to the day-to-day cost of energy and may not attract much support from the wider body of consumers.

The third objective of energy policy, tackling climate change, only entered centre stage in the early 1990s. However, it poses a huge problem for policymakers throughout the world. In framing energy policy it is important that the wider policymaking process sets out clearly the objective for the energy system in terms of reducing greenhouse gas emissions. The task of energy policymakers is to achieve those objectives at minimum cost to consumers.

The way the costs and benefits of policy are distributed across affected groups tends to receive less attention than other aspects of energy policy, but they remain a vital dimension of public policy. In this paper, where appropriate, we consider the effects of energy policy choices on the distribution of costs and benefits between one country and another; between producers and consumers; and, in some cases, between richer and poorer consumers. The distributional effects of policy are obviously important for policymakers and they can also affect the public acceptance of policy. Policies that are seen to be unfair may fail to gain public acceptance, even if they score highly on other criteria. In some cases the choice of policy may even be determined by whether or not it is beneficial for some key players in the energy sector, rather than whether or not it is beneficial for society as a whole.

Ireland has seen quite a successful move to economic regulation over the last twenty years in the areas of energy and communications. Under this regime the political system sets the broad objectives of energy policy and it is the job of the economic regulator, in the case of energy the Commission for Energy Regulation (CER), to try to achieve those objectives. However, it can be difficult for regulators to balance a number of different objectives, something that is really the prerogative of the political system. Economic regulation works best where the objective for the regulator is to maximise consumer welfare, subject to meeting the objectives on climate change, energy security and distribution set by the political system.

The approach taken in this paper has been to concentrate discussion on areas of energy policy where new issues have surfaced since our last publication in 2011, or where new research has become available which throws light on how policy should evolve over the coming decade. In undertaking this work we address quite

a number of the questions raised in the recent Green Paper on energy policy (Department of Communications, Energy and Natural Resources, 2014).

We first discuss in Chapter 2 energy policy in Ireland in recent years and the external background for Irish energy policymaking is considered in Chapter 3: we highlight EU and UK energy policies that affect Ireland both directly and indirectly. In Chapter 4 we focus more specifically on Ireland and consider a range of issues affecting energy supply, including both gas and electricity. Chapter 5 looks at issues affecting the demand for energy and conclusions are set out in Chapter 6.





# Chapter 2

## Energy Policy in Ireland

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This chapter gives a brief history of the recent direction of Irish energy policy. The 2007 Government White Paper spelt out three main strands of Irish energy policy: competitiveness, energy security, and sustainability.

The underpinning Strategic Goals in promoting competitiveness were:

- Delivering competition and consumer choice in the energy market;
- Delivering the All-Island Electricity Market Framework;
- Ensuring that the regulatory framework meets the evolving energy policy challenges;
- Ensuring a sustainable future for Semi-State Energy Enterprises;
- Ensuring affordable energy for everyone;
- Creating jobs, growth and innovation in the energy sector.

The underpinning Strategic Goals on energy security were:

- Ensuring that electricity supply consistently meets demand;
- Ensuring the physical security and reliability of gas supplies to Ireland;
- Enhancing the diversity of fuels used for power generation;
- Delivering electricity and gas to homes and businesses over efficient, reliable and secure networks;
- Creating a stable attractive environment for hydrocarbon exploration and production;
- Being prepared for energy supply disruptions.

The underpinning Strategic Goals on promoting sustainability were:

- Addressing climate change by reducing energy related greenhouse gas emissions;
- Accelerating the growth of renewable energy sources;
- Promoting the sustainable use of energy in transport;
- Delivering an integrated approach to the sustainable development and use of bioenergy resources;
- Maximising energy efficiency and energy savings across the economy;
- Accelerating energy research development and innovation programmes in support of sustainable energy goals.

In 2007, the European Union agreed to climate and energy targets. These targets were: a 20 per cent reduction in greenhouse gas emissions by 2020 from 1990 levels; a 20 per cent increase in energy efficiency by 2020 with respect to business as usual; and ensuring that 20 per cent of the EU's energy consumption comes from renewable sources by 2020.<sup>4</sup> Under the terms of the Renewable Energy Sources Directive, each Member State was set an individually binding renewable energy target, which contributes to the achievement of the overall EU goal.

Apart from a sub-target of a minimum of 10 per cent biofuels in the transport sector that applies to all Member States, there is flexibility for each country to choose how to achieve their individual target across the sectors. Ireland's overall target is to achieve 16 per cent of energy from renewable sources by 2020.

Ireland's National Renewable Energy Action Plan NREAP, consistent with the EU directive, was published in 2009.<sup>5</sup> In that plan the government set a target of sourcing 40 per cent of electricity consumption from renewable sources by 2020. In transport there was an initial target of using biofuels for 4 per cent of road transport fuel consumption, increased to 6 per cent from January 2013. The Government set a target of 12 per cent renewable heat by 2020.

The REFIT (Renewable Energy Feed-In Tariff) scheme was implemented to help meet the renewable target in electricity. It guarantees a minimum price for renewable electricity to investors and also provides a small subsidy independent of electricity prices. The first phase granted support for onshore wind generation, hydro and biomass for up to 15 years. In 2009 the scheme was extended and offered higher price guarantees to additional categories, including bioenergy, offshore wind, wave and tidal (Devitt and Malaguzzi Valeri, 2011). It is in the course of being extended to include biomass co-firing in peat stations.<sup>6</sup>

After many years of deliberation, a carbon tax was introduced in 2010, which applies to much of the economy that is not covered by the EU Emissions Trading Scheme. A number of studies have shown that this tax is likely to reduce

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<sup>4</sup> Tol (2011), considers the costs and benefits of this policy at an EU level.

<sup>5</sup> NREAP, The National Renewable Energy Action Plan, is available at: <http://www.dcenr.gov.ie/NR/rdonlyres/C71495BB-DB3C-4FE9-A725-0C094FE19BCA/0/2010NREAP.pdf>.

<sup>6</sup> The document that outlines the third extension of REFIT is: <http://www.dcenr.gov.ie/NR/rdonlyres/718E8541-7ADD-4FB2-A471-B6081C435625/0/REFIT3BiomassTermsandConditions2012.pdf> (accessed 25 September 2014).

emissions at minimum cost. In fact, if the revenue from the tax substitutes for taxes on labour the net impact on the economy is likely to be positive, as well as serving to reduce emissions (Fitz Gerald and McCoy, 1993 and Conefrey *et al.*, 2012).

Since the adoption of its first package of measures, the EU has gradually become more ambitious. The most recent climate and energy package calls for a 40 per cent reduction of green house gas (GHG) emissions from 1990 levels by 2030; an EU-wide target of at least 27 per cent energy consumption met by renewables by 2030; confirmation of the role of energy efficiency, with a proposal to increase energy efficiency by 30 per cent with respect to business as usual projections for 2030; a reform of the EU-ETS market; the establishment of indicators to keep track of the effect of these policies on energy affordability and security; a new governance framework ensuring that Member States compile their National plans following a common approach (European Commission, 2014).

These changes have been accompanied by an effort to integrate electricity and natural gas markets across Europe with the 3rd legislative package.<sup>7</sup> The goal of the 3rd legislative package is to offer more and better products and services to consumers, increase competition and enhance security of supply.

In May 2014, the Department of Energy Communications and Natural Resources published a Green Paper on Energy Policy (Department of Energy, Communications and Natural Resources, 2014), which elicits opinions on how to meet the varied challenges facing the Irish energy sector. This ESRI Research Paper contributes to the debate by summarising the implications for energy policy of a wide range of research undertaken in recent years.

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<sup>7</sup> The package includes three regulations: [http://ec.europa.eu/energy/gas\\_electricity/legislation/legislation\\_en.htm](http://ec.europa.eu/energy/gas_electricity/legislation/legislation_en.htm) (accessed 15 September 2014).



# Chapter 3

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## The External Background for Irish Policymaking

A vital factor in developing Irish energy policy over the coming decade will be the external context within which the Irish economy and the Irish energy sector will operate. Many of the key issues that will arise for energy policy in Ireland are determined at the level of the European Union (EU). Also policy on global issues, such as climate change, is mediated through the EU. However, even where there is direct domestic competence over energy policy decisions, the policy context will be heavily influenced by EU policy and by the energy policies of our neighbours, especially that of the UK.

In this chapter we outline some of the channels through which the external policy environment may impact on domestic energy policy. We first consider EU policy, both policies aimed at tackling climate change and also policy on integrating the EU electricity market. In both cases we examine the EU policy approach in terms of its effects on efficiency and in terms of the potential distributional effects of the instruments chosen. We then turn to a UK policy initiative that potentially has important implications for Ireland – the introduction of a carbon price floor.

### 3.1 EU POLICY

EU policy on climate change is evolving and the new policies that will be formulated over the coming year for the period after 2020 will have major implications for Ireland. EU policy on developing a single electricity market is also evolving. By 2016 Ireland and Northern Ireland will have to make significant adjustment to the Irish electricity market to ensure consistency with these new rules.

As a member of the EU many aspects of Irish energy policy are determined by EU directives:

- Current and future EU policy on restricting emissions of greenhouse gases from both the electricity sector and from the rest of the economy will be a key driver of developments in Ireland.
- The provisions of EU directives on energy security (mirroring those of the International Energy Agency) play an important role in providing security for Ireland. In particular, the provisions for dealing with a shortage of gas or oil, through sharing scarce resources within the EU, provide a very important legal guarantee for Irish consumers.

- The drive to develop an integrated EU electricity market has major implications for the electricity sector in Ireland and elsewhere in the EU.

The external energy policy context is of vital importance to Ireland but, rather than providing certainty about the future, it is a currently a major source of uncertainty.

EU policy on climate change post-2020 has yet to be determined, though the draft of the proposed policy is now published. The change in configuration of EU policy that is likely to take place in the post-2020 period will also have consequences for national policy in countries such as Germany and the UK. UK and German energy policy has shifted frequently in the past fifteen years. Helm (2014) points out that UK energy policy has gone from promoting liberalised markets, at the end of the 1990s, to relying on an extensive number of increasingly complex state interventions, including a move toward technology-specific subsidies for renewables and price guarantees for nuclear power. Not surprisingly, because these have led to higher costs for consumers, there has been a backlash and measures aimed at reducing the impact on final prices are being considered. Examples include a sudden withdrawal of subsidies for farm solar and Treasury's introduction of the Levy Control Mechanism in 2011 to limit total subsidies paid out by the Department of Energy and Climate Change (DECC).

Germany has engaged in a very ambitious low-carbon plan for the electricity system, known as *energiewende*, mostly through the adoption of renewables. This has led to high costs for consumers: the renewable energy surcharge for 2014 is eurocent 6.24/kWh.<sup>8</sup> The energy surcharge is an overestimate of the cost of the plan per kWh, since a large share of industrial consumption is exempt from payments. In any case, it compares unfavourably to an average German electricity spot price of eurocent 3.8/kWh in 2013 (Agora *Energiewende*, 2014). The *energiewende* has been accompanied by a nuclear power phase out, initially decided in 1998, reversed by the incoming government in 2009 and reversed again in 2011 following the near meltdown at the Fukushima nuclear plant (Von Hirschhausen, 2014).

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<sup>8</sup> The Irish Public Service Obligation, despite recent increases, is much smaller than the German payment, at eurocent 2.0/kWh in 2014-2015, assuming a yearly residential consumption of 3.3MWh (CER, 2014c). Less than a third of this cost supports renewable energy.

The possibility of a UK exit from the EU in the second half of the decade would have huge consequences for Ireland, not least in the sphere of energy policy.

### 3.1.1 EU Climate Change Policy – Effectiveness

The post-2020 EU policy on climate change has yet to be finalised, though we now have the initial European Commission proposals. The failures of the current policy and its negative impact on both cost and on the incentives to reduce greenhouse gas emissions has until now not been fully recognised at an EU level. The uncertainty about policy post-2020 is already affecting the energy sector, making finalisation of the future policy a priority for EU policymakers.

The policy on renewables, involving binding targets for deployment by 2020, has had a serious impact on the cost of electricity in Europe, while delivering limited reductions in carbon emissions (Böhringer *et al.*, 2009). The emissions trading regime has not been effective as the price of carbon has collapsed. Taken together these two policies have involved an additional cost burden for consumers in Europe, combined with a disappointingly small impact on emissions.

Zachmann *et al.* (2014) suggest that it would probably have been more efficient if the EU had devoted more resources to researching how to reduce the cost of renewable technologies rather than subsidising their deployment at an early stage in their development. While the extensive deployment of renewables has seen a fall in their cost, it has also resulted in a large installed base of expensive renewables that will have to be paid for by consumers for many years to come. In the German case, the government committed to paying for solar panels at very high prices, while the cost of the technology was falling rapidly over time. Zachmann *et al.* (2014) argue strongly for a change in the balance between subsidies for deployment and subsidies for research into increasing the efficiency of renewable technologies. If, instead of a rapid deployment of immature renewable technologies, a fraction of what is being spent on renewable subsidies had been spent on appropriate research, Germany would today be able to buy the same technologies at dramatically lower prices. By contrast, in the Irish case much of the deployment of onshore wind energy has taken place after a major fall in costs in the 1990s.

Because energy is a very capital intensive industry and the assets generally have long lives, it is important to agree on the EU policy stance for the next decade as soon as possible. Lynch, Tol and O'Malley (2012) show how the optimal shape of the North-Western European electricity grid would be very different depending

on whether there is an EU policy on encouraging renewables after 2020 and on how that policy is structured. This need for greater clarity on the stance of future EU climate change policy is even more crucial in the case of greenhouse gas emissions.

Problems with the current EU policy on climate change have created considerable uncertainty for investors. The collapse in the carbon price within the EU emissions trading scheme has meant that there are currently very weak incentives for business to invest in carbon reduction technologies in the industrial sectors covered by emissions trading (principally electricity). The uncertainty about the future price makes it very difficult for new investors and, if this uncertainty continues, it will have a big impact on the sector over the coming decade (Helm, 2010). At the inception of the EU-ETS scheme there had been an expectation among investors that the carbon price would be significant, incentivising some investments. However, the fact that the carbon price has turned out to be close to zero has meant that investors lost money. The result is an increase in caution among new investors. This seriously militates against firms undertaking investment which would produce a major reduction in carbon emissions.

Even if the EU puts in place a more effective emissions trading regime for the post-2020 period, the legacy effects of the failures in the current regime will take some time to wear off. The result will be considerable uncertainty and, as a result, sub-optimal investment in emissions saving technologies. A much more suitable instrument for implementing policy to reduce greenhouse gas emissions would be a fixed price or tax on carbon, which could be gradually increased in a pre-announced manner to achieve a significant reduction in emissions.<sup>9</sup> Such a policy would provide greater certainty for investors than the current regime and it would, hence, be more likely to incentivise the desired investment in new technology at a lower cost. Other hybrids, such as a carbon price floor implemented at the level of the EU, could also prove effective. The issue of a carbon price floor is discussed in more detail later.

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<sup>9</sup> Because the energy sector is very capital intensive a key element of the cost of energy is the cost of capital. Price uncertainty greatly increases the cost of capital (see Box A below). By providing greater certainty about future returns a carbon price will allow the necessary investment to be funded at a lower cost. While governments may be uncertain about the precise trajectory that the price of carbon should follow to achieve a specified emissions target, the costs of overestimating the appropriate price are likely to be limited in the context where the price of carbon needs to rise over time. Temporarily overshooting the price in one year could be offset by a standstill in the price until it is brought into line with the level needed to achieve an appropriate reduction in emissions.



First indications of the latest EU thinking on climate change policy post-2020 look encouraging. It seems that the problems of having a separate renewable regime have been recognised. Renewables per se do not have a value; they are useful to the extent that they result in lower greenhouse gas emissions or greater energy security. The experience with the current regime is that investment in renewables has been an expensive way to reduce emissions and a new EU regime should allow countries, firms and individuals to choose the most cost-effective way to reduce emissions. Compared to the current regime, this should reduce the cost of meeting the ambitious targets for a reduction in greenhouse gas emissions by 2030.

### **3.1.2 ETS Versus Non-ETS Markets for Carbon. What Should the European Policy Be?**

On January 1, 2005 the European Emissions Trading Scheme (ETS) was introduced as a major pillar of European climate policy. It was a key element in the EU's plan to adhere to the Kyoto Protocol on emission reductions. Around half of all emissions are regulated under this "cap and trade" system (Devitt and Tol, 2012). Within this cap, companies receive or buy a finite amount of emission allowances which they can trade with one another as needed. This gives a price for carbon and a financial cost/value to each tonne of emissions saved. As the price of permits increases, investment in clean low-carbon technologies is encouraged allowing for a sustainable reduction in carbon emissions.

Despite the introduction of the EU-ETS, conventional generation retains an important role in European electricity systems. Renewable generation, such as wind and solar, is intermittent so it has to be accompanied by fully dispatchable plants to maintain system reliability. Traditional coal plants are amongst the largest emitters of CO<sub>2</sub> per unit of electricity generated. If coal plants are to generate despite policy objectives of minimising CO<sub>2</sub> emissions, one possibility is to capture the carbon released during combustion and store it permanently. Despite a huge research effort into carbon capture and storage (CCS), there is still no commercially operating CCS power plant anywhere in the world.

The method used to price carbon can have a strong influence on the viability of investments in innovative technologies with uncertain costs such as CCS. Walsh *et al.* (2014) examine the case of a 500 MW super critical pulverised coal power plant to consider the optimal time to retrofit it with CCS (Box A). They consider two policy scenarios: the first includes a carbon tax with a certain level and rate of change over time, such as the carbon floor introduced in Great Britain (GB) in

April 2013; the second consists of an uncertain price of CO<sub>2</sub> emissions, similar to the current EU-ETS.

As CCS technology evolves and is adopted, its cost is likely to fall. For this reason a declining investment cost function is included in the analysis. The research results suggest that, in the case of the certain carbon emission cost, investment will optimally occur in 2020, whereas when the price of carbon is volatile and uncertain there will be no investment within the lifetime of the plant.

The policy implications of this work are clear: investment in reducing carbon emissions will occur earlier under a regime which guarantees the price of carbon rather than under a trading regime like the current ETS.

#### Box A: Optimal Timing in CCS Retrofitting

*Darragh Walsh*

Walsh *et al.* (2014) analyse the decision to invest in Carbon Capture and Storage (CCS) by taking the example of a 500 MW super critical pulverised coal (SCPC) power plant with 80 per cent capacity factor, assumed to be operating as a base-load plant. The cost to retrofit the plant with CCS is estimated to be €214.5 million, decreasing at a rate of 2 per cent per year (as in Abadie and Chamorro, 2008).

On the basis of these assumptions, the optimal timing for investment is found by maximising the net present value (NPV) of the value of investing in CCS. When the path of the cost of carbon dioxide emissions is certain, as in the GB carbon floor case, simple calculus techniques allow the authors to determine the optimal time to invest, determined in this case to be 2020 (i.e., the NPV of the option is maximised in 2020 in GB).

Due to the inherent volatility in the price of a traded permit, the calculation of the optimal time to invest in a CCS retrofit for the rest of Europe is more difficult. With reasonable assumptions the authors show that it was not optimal to invest within the normal lifetime of a coal plant (40 years), given the low level of the ETS permit price.

A key result in this analysis is that if the volatility of the ETS permit price increases, then the optimal time to invest also increases. This is a clear indication that the volatility introduced by a tradable permit has an adverse effect on investment in carbon abatement technologies such as CCS.

### 3.1.3 EU Climate Change Policy – Distributional Effects

The distributional impact of EU energy and environmental policy receives very little attention in discussions on policy formation. In some cases the distributional impact is unclear when the policy is agreed, and will only become apparent with a long delay as the policy is implemented. This uncertainty may facilitate policymaking, helping to get agreement across many member states. However, it favours producer lobby groups and, as a result, it will often disadvantage

consumers. It also has uncertain implications for income distribution between countries.

Where the distributional outcomes are likely to be limited, this lack of transparency may not be a problem – potential distributional gains and losses may be dominated by the overall benefits to society of the policy measures. However, if the outcome of a particular policy is perceived, *ex post*, as being patently unfair, disadvantaging many consumers, companies or countries, and if the effects are large, the policy itself may not be sustainable. Thus, persuading EU members to accept a policy which may have major, but unknown, distributional impacts in the future may be unwise in the long run.

One area of EU policy where this uncertainty about distributional effects has been an important feature of decision making has been the sphere of environmental policy. The choice of a permit regime, rather than a tax regime, to tackle greenhouse gas emissions in key sectors meant that the cost of the policy was unclear at the time it was agreed.<sup>10</sup> This minimised the opposition to the policy at its inception. Even if the policy were successful by raising the price of greenhouse gas emissions, the cost to consumers would still have been less clear than if a tax had been used. When the European Commission proposed a carbon tax in the early 1990s, which would have made clear to all concerned the costs involved, it was rejected by member states. Thus, policies which render the cost of reducing emissions opaque may generate less opposition from consumers or countries who have to pay those costs.

The adverse distributional impact of the initial emissions trading policy was greatly aggravated by the decision to grandparent emissions permits. This conferred a major windfall gain on producers at the expense of consumers. This bought off the opposition from incumbent producers, who actually gained from the measure, while the potential losers (consumers and taxpayers, who would each lose a small amount) were unaware of what they were losing. Auctioning all permits would have produced a much fairer outcome as the transfer of resources would have been from consumers to governments rather than from many consumers to a small number of producers; governments would then have been able to redistribute the revenue to achieve any desired distributional outcome

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<sup>10</sup> In the event, the costs turned out to be lower than anyone expected as the carbon price collapsed, but the environmental benefits realised by this policy were, as a result, also very limited. Another case where environmental legislation had unexpected cost consequences that caused problems for governments, in this case the UK government, was the Urban Waste Water Directive (Smith, 2000).

across consumers. Moreover, grandparenting may also limit the reduction in emissions, rendering the policy less effective from an environmental point of view, while increasing the costs for consumers (FitzGerald, 2004a; FitzGerald and Tol, 2007). This is because the prospect of future rounds of grandparenting may encourage “dirty” plants to remain in business, and the windfall gain to polluting producers from grandparenting may provide them with a significant advantage relative to new entrants in terms of the availability and cost of capital. While in the current round of emissions trading there is a move to auctioning permits, grandparenting still plays an important role.<sup>11</sup>

The EU decision to set national limits for emissions of greenhouse gases from the sectors of the economy not covered by the EU-ETS also has the potential to produce a major redistribution of income, in this case between member states. This regime covers about half of all EU carbon dioxide emissions (Devitt and Tol, 2012). Tol (2009) shows how, as originally conceived, the policy of national quotas would have been likely to result in a major redistribution of income across member states and a very inefficient outcome in terms of the cost of reducing emissions within the EU. Following on submissions from the Irish and other governments, the original scheme was modified to allow countries to trade quotas (for the sector of the economy not covered by the emissions trading regime). While this will potentially reduce the cost of implementing the policy, it is still likely to lead to significant redistribution of income between member states. Also, it is still not clear which states will be the winners and which will be the losers.

A defining characteristic of the non-ETS market, because it is restricted to governments, is that it has a relatively small number of potential buyers and sellers. As a result, market power is possible on both the demand and supply side, which could further enhance the undesirable distributional effects of the regime.

Devitt and Tol (2012) argue that, under efficient market conditions, all countries will act as price takers and will trade permits to minimise their costs and achieve the efficient allocation of permits and emission abatement activities. Buyers with market power, or strategic buyers, will try to lower the price of permits while strategic sellers attempt to increase the price. With both strategic buyers and

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<sup>11</sup> In developing the emissions trading scheme for EU aviation the likely value of free permits for incumbent producers was reflected in strong lobbying by some airlines to reduce the stock of permits, increasing the value of their “free” permits.

sellers the effect on the permit price is ambiguous. However, strategic behaviour unambiguously reduces the overall level of trade, leading to welfare losses. The authors conclude that regulation is necessary to contain market power.

Whether countries win or lose from the regime to limit emissions in the sectors not covered by emissions trading will depend on whether they buy or sell national quotas. In turn, this will depend on the initial allocation of quotas across member states agreed by the EU, the growth rates of the individual economies and the structure of their economies, which determines their carbon intensity and their marginal cost of abating carbon dioxide emissions. Thus, the policy could result in significant redistribution from richer to poorer member states. However, it is also possible that the redistribution could operate in the opposite direction; for example, it is possible that Portugal might have to buy quota from Germany or the Netherlands. In either case the policy may give rise to unplanned international transfers, which are large in size and which may not contribute to an increase in the welfare of EU citizens or to meeting key EU objectives.

In the latest Irish government plan for the economy (Department of Finance, 2013; Department of Finance, 2014) the authors model the provision for significant payments by Ireland to acquire carbon permits towards the end of this decade. If the quota is bought from poorer countries, such as Poland, then there will be de facto a redistribution from one of the wealthier countries in the EU (Ireland) to one of the poorer. However, there is no guarantee that this will be the case.

Discussions are currently taking place about climate change policy for the EU after 2020. Initial suggestions were that the EU would agree emissions quotas for each country and that these would involve a dramatic reduction by 2050 in emissions compared to the current situation. The proposals included emissions from agriculture in the suggested national quotas. Research using the TIMES model of the Irish energy system indicated that, on the assumption that agriculture continued to produce livestock based products for the foreseeable future, there would be a massive problem for Ireland (and a related cost) in meeting the initial suggested 2050 target (Chiodi *et al.*, 2013a and 2013b).<sup>12</sup> In

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<sup>12</sup> The TIMES model is an EU-level model designed to analyse the role of energy technologies in meeting climate change and energy policy goals. It covers the EU28 energy system plus Norway, Switzerland, Iceland and the Balkan countries from 2005 to 2050. The Irish version of the model is described in Chiodi *et al.* (2013b).

practise, if agriculture continued to produce, meeting the target would require negative emissions from the rest of the Irish economy.<sup>13</sup>

Estimating an efficient and equitable set of national emissions quotas requires national cost parameters and abatement potentials for key emitting sectors to be modelled accurately across all member states. The agriculture example illustrates how this can fail: Ireland's livestock is relatively carbon-efficient, since it is largely fed on grass rather than relying on other feedstock that produces higher emissions. However, there is very little abatement potential because the emissions are generated by the digestive system of the cattle. Far from favouring a system whose carbon efficiency can help reduce global emissions, a crude national quota could imply that carbon efficient Irish production should be sharply reduced. Given that targets are on the production side and do not directly relate to consumption, reducing Ireland's agricultural production would probably not even reduce global emissions, because producers in other countries would likely replace the lost production, and many are less carbon-efficient.

Even if in the final agreement the quotas are modified to exclude agriculture, and even if a good model is used to try and ensure equal costs of compliance across the EU, the outcome will, inevitably, be very different from the model predictions due to the inability of models, however detailed, to predict accurately the costs of abatement for individual countries 20 or more years ahead.

Thus, the use of national targets for emissions as the key instrument of EU long-term policy on reducing greenhouse gases carries with it the certainty that it will, at best, lead to major and unpredictable transfers of resources between countries over a very long period. At worst, if trading is not permitted, it could lead to aggregate EU emissions being reduced at massively greater cost than under a more sensible policy.

No amount of research will be able to produce accurate forecasts of national abatement costs far in advance. Under these circumstances national targets are not the most efficient way to proceed. An EU target for emissions reduction, combined with a harmonised policy instrument for achieving it across the EU, is the only coherent policy approach. The best policy instrument would be a

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<sup>13</sup> The total emissions from agriculture would exceed the total allowable for the economy – hence the phrase “negative” emissions reflecting the impossibility of meeting such a target with agriculture continuing to produce.

common rate of carbon tax across the EU. However, an alternative mechanism would be to have a quota regime covering all the sectors across the EU, with all of the permits being auctioned at an EU level. The issue of a fair distribution of the revenue would then be the subject of a separate discussion at EU level.<sup>14</sup> This would minimise the cost for EU consumers and for the wider economy of reducing greenhouse gas emissions, while ensuring that there would be no windfall gains to producers (or countries) paid for by consumers.

The major defects in the current EU policy approach, involving national and sectoral quotas for emissions, have been recognised in the latest EU proposals for the post-2020 period (European Commission, 2014). By providing for a single EU quota the regime should ensure that the cost of greenhouse gas abatement is the same for all households and firms in the EU. This will limit the scope for unforeseen distributional effects. It will also ensure that the target for emissions reduction will be met at the lowest possible cost to the EU economy. However, the full details of this policy remain to be worked out and it will be some time before a final EU policy position is adopted.

#### **3.1.4 EU Policy on Global Warming – Policy Implications**

Because of the capital intensive nature of the energy sector it is important to provide clarity about EU policy out to 2030 as soon as possible. Policy uncertainty is costly for investors and will result in an unnecessarily high-cost solution to the crucial problem of reducing greenhouse gases. It will also delay progress in reducing emissions.

While it is important to set targets for reducing EU emissions over the period to 2050, these targets should not be enshrined in law. Instead, using suitable models, an appropriate trajectory for the price of carbon should be chosen and this price should be what is enshrined in law. Thus the EU should move away from using the Emissions Trading regime towards using an explicit price, either as a carbon tax, or at least as a carbon floor along the lines of the recent UK policy.

The current approach of using a combination of policies – setting national targets for emissions in the non-ETS sectors and then using an ETS scheme for other sectors – has proved ineffective. This regime is not transparent: consumers and

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<sup>14</sup> One possibility would be to distribute the revenue in relation to where the permits are actually used, ensuring no balance of payments effects for individual countries as a result of the regime.

tax payers are not told what the price of the policy is up front. While it may help produce initial agreement to the policy by disguising what it involves in terms of costs, it does not contribute to decisions that are efficient in the long term. It also has the potential to result in unpredictable but very large transfers from consumers to producers or between countries, transfers that have no justification in terms of economic efficiency or equity.

Moving EU policy away from targets for renewables makes sense as the current regime has proved a very expensive way of reducing greenhouse gas emissions. It would have been better if more funding had been put into research to develop cheaper renewable technologies and less into subsidising the deployment of existing expensive technologies. For the future, if an appropriate regime is implemented at EU level to incentivise a reduction in greenhouse gas emissions, this should, on its own, provide appropriate incentives to deploy renewable technologies. Then the market will decide on the cost-minimising way of meeting the objective of reducing greenhouse gas emissions.

### 3.1.5 EU Policy – Internal market for electricity

A major EU initiative to develop an internal market in electricity is under way: the Target Model (Gorecki, 2013). The goal is to benefit consumers across Europe by reducing the total cost of meeting the EU's electricity needs. To date the EU approach is to first specify rules on trading electricity across borders. However, the current Single Electricity Market (SEM) in Ireland, which already spans national borders and has proved effective (Deane *et al.*, 2015), would not be consistent with these rules on cross border trading and, as a result, will need to be modified (Gorecki, 2013). Ireland and Northern Ireland have obtained a two year deferral in meeting the guidelines and the redesigned SEM will, therefore, need to comply with EU legislation by the end of 2016. The redesign of the SEM is currently under consideration and we discuss this issue later in Section 3.2.

Over the last twenty years there was adequate electricity generating capacity across much of the EU and there was limited need to invest in new plant. This was true in the UK, as well as countries such as France and Germany. Markets responded to this surplus of generating capacity and prices in Europe fell below long-run marginal cost. This meant that there was no incentive to invest in new generating capacity to serve these markets, which was appropriate given the excess capacity. However, in the Irish case, because of the rapid growth in the economy in the period to 2007, major investment in new generating capacity was needed. Differences in investment requirements resulted in the development of different market structures in Ireland and the other EU members.



The position in the EU has changed as there is now a need for major capital investment in electricity infrastructure (generation, transmission, and distribution) over the coming fifteen years. The German government decision to close their nuclear plants early leaves a major gap in generation, which must be filled early in the next decade. The obsolescence of UK nuclear plant and the requirement to close many of its coal plants also calls for huge investment in generation in GB. In France the nuclear plants are approaching the end of their useful life and the funding of replacement plants will put huge pressures on the balance sheet of their owner EDF. In addition, to the extent that investment continues in capital intensive renewables, this will add to funding needs. Finally, there is a major requirement for new investment in the transmission and distribution grid across the EU.

The need for major new investment in generation will require the EU electricity market to move from a situation where prices are below long-run marginal cost to one where these costs are covered. This will see electricity prices rise across the EU, even if fuel prices remain unchanged. This could see a narrowing in the gap in prices between Ireland and GB (Deane *et al.*, 2015), as well as with other countries such as Germany.

However, market structures across much of Europe will not necessarily deliver a price equating to long-run marginal cost. The bilateral contracts market in GB has produced an (estimated) wholesale price which is below long-run marginal cost while allowing the retail margin to be relatively large (Deane *et al.*, 2015). Great Britain is currently considering whether and how a payment for capacity can be introduced to incentivise investment in a transparent manner. In order to see new investment in nuclear the UK government has had to provide investment guarantees to EDF, an ad hoc solution to the expected shortage of capacity. Some system of capacity payments therefore seems inevitable in GB. However, if capacity payments are added without reductions to current high retail margins, GB consumers will end up overpaying for electricity. In Germany the authorities are also considering how best to provide payment for capacity (Elberg, *et al.*, 2012 and Saha, 2013).

Thus the long-term shape of the EU market is uncertain. It is still not clear whether national market structures will evolve into a consistent framework. It is also not clear how consistent these market structures will be with the SEM. The EU rules aim to ensure consistency between different markets by providing rules for cross-border trading. However, with national market structures themselves

evolving across a number of important EU member states it is difficult to predict the outcome. Zachmann (2014) suggests the need for the development at an EU level of an appropriate market structure.

The development of the EU electricity market, the increasing deployment of wind in Ireland, the developing market in renewables and the wider need to enhance security and competitiveness all require increased interconnection between the Irish electricity market and the rest of the EU. However, there are a range of questions around how much interconnection there should be between the Irish market and the rest of the EU and where this interconnection should take place.

It is not clear how much interconnection there will be between GB and the rest of the EU. At present, because of the limited interconnection, GB is effectively a separate market from the rest of the EU, with prices each time period being set based on supply and demand conditions in the GB market. However, with increasing interconnection GB would eventually become part of a wider EU market, with prices set by the EU demand and supply conditions. Irish concerns about imperfections in the GB market would no longer be relevant and interconnection to GB would have the same effect on prices as interconnection to France. However, for the next five to ten years the GB market is likely to be largely independent of the rest of the EU and enhanced interconnection between Ireland and GB would gradually integrate Ireland into the GB market.

If the GB market remains independent of the rest of the EU, enhanced interconnection with GB would leave Ireland vulnerable to any problems in the GB market. Under these circumstances enhanced interconnection with the rest of the EU, most probably to France, could provide useful diversification, reducing risk for Irish consumers. If, instead, GB becomes part of the wider EU market through extensive investment in new interconnectors, connecting directly to France would prove unnecessarily costly for Ireland. Thus, the lack of clarity about GB plans makes long-term planning for the development of Irish interconnection difficult.

The issue of who will pay for enhanced interconnection and how the costs and benefits of enhanced interconnection will be shared is dealt with in the next section.

The move to develop an integrated EU electricity market is to be welcomed. In the long run it is likely to prove of substantial benefit to Ireland and other

member states. It will require some changes in the Irish market, a market which has proved successful in terms of providing a secure electricity supply at minimum cost.

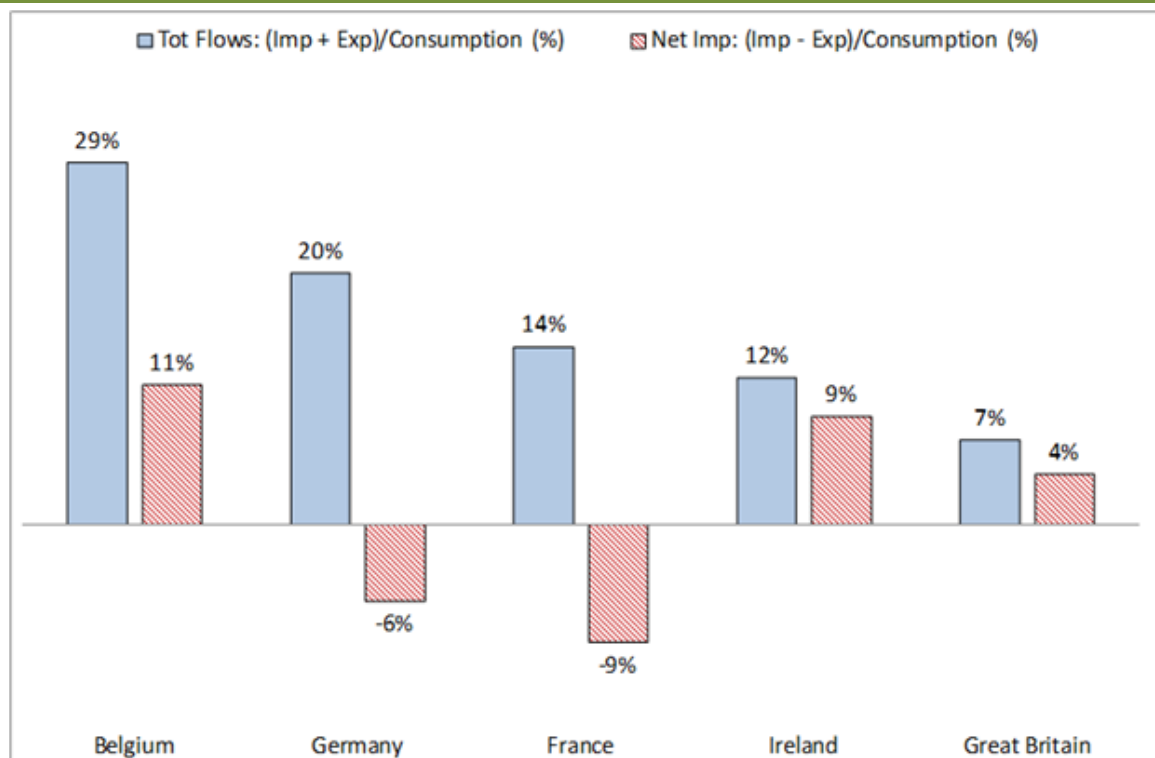
### **3.1.6 EU Policy – Interconnection and the Distributional Effects of the EU Internal Market for Electricity**

Moving from the current fragmented electricity market structure to an integrated market may have significant distributional implications in the short to medium term. In countries or markets where electricity prices are below the EU average, the introduction of an integrated market is likely to see prices rise as exports will increase. This will be good for producers in countries which currently have low prices, but bad for consumers in those countries. On the other hand, consumers in countries with high prices will gain from a common market and a common price, while producers in such countries will lose. The issue of the distributional impact of developing the single electricity market has, so far, been ignored. Just because there may be a Pareto optimum, where the gains from integration would be more than enough to compensate any losers, does not avoid the issue of what approach policymakers should take to distributing the gains. These distributional effects could be large, even if they are in theory only temporary. Because these “temporary” distributional effects could last for a decade or more, policy needs to take them into account. The distributional effects may well necessitate special rules on how the market integration is financed. For example, it may be the case that the majority of new investment in interconnection should be financed by gainers rather than losers.

Over the last fifty years the freeing of trade in goods, either within the EU or through the World Trade Organisation (WTO) has often resulted in losers and gainers, at least in the short run. These short-run costs have been clearly overshadowed by the much larger gains that all countries have reaped from free trade. However, unlike the case of electricity, freeing of trade in goods required legislative changes rather than major investment by utilities. By contrast, in the case of electricity, a key factor in developing the single market will be the construction of increased interconnection between markets. This raises the question of who should pay for the infrastructure needed to allow trade to happen. Following the model of trade in goods, where importers and exporters pay for their own transport costs, in the case of electricity it would be appropriate that those who trade should pay the full costs of the necessary infrastructure.

Moreover, efficient flows along interconnectors do not arise automatically when new infrastructure is built. McInerney and Bunn (2013) show how prices and flows along the Moyle interconnector have not been efficient to date. The changes that will be made to the SEM to comply with the EU Target model should address some of these inefficiencies.

FIGURE 1 Interconnection Flows as % of Consumption, 2013



Source: Authors' elaboration of data from ENTSO-E: Statistical Factsheet 2013.

Currently, the SEM is less interconnected than other small systems in continental Europe. For example, interconnection capacity in Belgium was about 25 per cent of peak demand in 2012 (Cantillon, 2013). Equivalent values for the SEM are closer to 15 per cent. Figure 1 shows that for 2013 total flows (the sum of imports and exports) were equivalent to 29 per cent of consumption in Belgium and only 12 per cent for Ireland. Germany and France also had higher proportions of flows in and out of the country, an indication of how interconnected continental Europe is. Flows for Ireland are driven by imports from the UK (Great Britain and Northern Ireland) into the Republic. Associated with limited exports, this leaves net imports at 9 per cent of total consumption. Germany and France, on the other hand, are net exporters, shown by the negative sign on net imports. Belgium, connected with many large neighbours, displays high levels of both imports and exports. Great Britain, despite being connected to France, the Netherlands, Northern Ireland and Ireland, has very limited flows as a proportion of total demand leaving it an "isolated" market.

Higher interconnection poses challenges for the SEM, both in the short and in the longer term. First of all, interconnection to the SEM is based on Direct Current (DC), instead of the Alternate Current (AC) interconnection typically found in continental Europe. DC interconnection is well adapted to the relatively long distances needed to link other electricity systems to the SEM and to the need to lay the cables under the sea. DC current, however, does not help maintain the system frequency of the grid, at least in the absence of additional investments in converters at the beginning and end of the connection.<sup>15</sup> Large amounts of interconnection and wind, also a non-synchronous source of electricity, might affect the reliability of the grid.

Currently interconnector flows have priority over wind generation in the SEM. McInerney and Bunn (2013) show that there are periods where the interconnector flows against its theoretically optimal direction. This has commercial implications; for example, wind generation in Ireland could be curtailed at times when demand is served (suboptimally) by imports through the interconnector.

Decisions on increased interconnection are likely to have long-term ramifications for the SEM, as there are both positive and negative consequences of full integration in the European North West (NW) market. If prices at the other node of the interconnector are consistently lower than the costs of a marginal Combined Cycle Gas Turbine (CCGT) plant in the SEM, thermal plants in the SEM will be mothballed or exit the market in the long run. Wholesale electricity prices in Ireland will be lower, but electricity policy in the SEM jurisdictions will be subordinate to the policies of NW European countries. Moreover security of supply in the SEM may decrease as domestic thermal plants close. If prices in NW Europe are higher than the prices in Ireland, the interconnection will be mostly used for exporting electricity at times of high wind generation (assuming that sufficient transmission is available at the other end of the interconnector).

In most countries in the EU electricity transmission is treated as a regulated industry. The investor (very often a publicly owned company) is guaranteed a

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<sup>15</sup> All users of electricity depend on a reliable supply of Alternating Current – AC. Users depend on the electricity supply maintaining a set frequency and voltage. Significant deviation from the standard can cause major damage to electrical equipment. Traditional power plants are able to help balance frequency and voltage, whereas providers of DC energy are not.

normal return on its investment. This guarantee is effectively provided by consumers rather than producers, as producers may come and go but consumers will always be there.<sup>16</sup> Thus, consumers of Europe will pay for the essential instrument to allow free trade in electricity while, in the short run, many may actually lose from the freeing of trade. This may seem unfair and it does raise the issue of whether the funding of the development of a European grid can be levied on those who will initially be the main beneficiaries or whether it must always be the consumer, even where they are the losers in some countries.

Interesting examples of where this issue has already arisen in Europe are cases of investment in transmission in Sweden and Belgium. In the case of Sweden the domestic authorities have been required by the EU to strengthen their transmission system to allow greater transit of cheap Norwegian electricity to outside markets (e.g., Denmark and Germany). Thus the Swedish consumer, who may see higher prices as a result of this investment, may have to fund this investment while the beneficiaries are likely to be Norwegian producers and German or Danish consumers.<sup>17</sup> Similarly, the transit of electricity through Belgium congests the Belgian transmission system, imposing costs on Belgian producers and consumers. This raises issues as to who should pay for additional investment in the Belgian grid.<sup>18</sup>

In the case of Ireland there is currently limited interconnection to GB. The interconnection already in place has been primarily paid for by Irish consumers.<sup>19</sup> This is probably appropriate as prices are currently lower in GB than in Ireland so that the higher the imports from GB the bigger the gain for Irish consumers and the bigger the loss for Irish producers. However, the impending capacity shortage in the GB market could potentially reverse this flow with Irish consumers, having paid for the interconnection, facing higher prices as a result of the investment. While this might be only a “temporary” phenomenon, it could last quite a number of years.

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<sup>16</sup> Where the cost of the investment is to be recouped over decades then the impermanence of producers (relative to consumers) means that producers cannot provide a credible guarantee of payment flows over a long period.

<sup>17</sup> The Norwegian producer will be able to get higher prices in Denmark and Germany, prices which will, inevitably, be passed on to Swedish consumers.

<sup>18</sup> Such an approach underlies the suggestion in Zachmann (2013) that consumers in all electricity network nodes that are predicted to receive more imports through a line extension should be obliged to pay a certain portion of the extension rather than socialising the cost across all users.

<sup>19</sup> There has also been an EU contribution. However, there has been no contribution from Great Britain as, to date, the gains were expected to accrue primarily to consumers in Ireland.

EU policy provides for the costs of interconnection to be recouped by user charges from the use of the infrastructure. This issue is discussed later in the context of gas infrastructure. However, the issues involved in electricity interconnection are rather different.

If enhanced interconnection produces a substantial change in price in Ireland it is likely to involve substantial flows in one or other direction through an interconnector. In that case the levying of a charge for use of the interconnector to cover its costs will ensure that Irish consumers (who effectively provide a no loss guarantee to the investor) will not end up paying for it in their bills. Even if the enhanced interconnection were to result in higher prices for consumers in Ireland they would not end up paying for the interconnection but the payment would come from the increased profits of producers in Ireland.

By contrast, if the price in Ireland falls, the reduction in price would be reduced because of the need to pay for the transmission costs of getting the cheaper electricity to Ireland. In that case consumers would end up paying for the interconnector through higher prices than if the interconnector were paid for by taxes, but they would still be receiving the benefit of lower prices.

It is only if the flow through the interconnector is low that the charges levied for its use would not cover its costs. As in the case of the gas interconnectors, discussed below, in this case the cost of the interconnector would still have to be paid for by consumers. In this case, as with the case of the gas infrastructure, it would be appropriate to treat that part of the cost of the interconnector not remunerated through usage charges as part of the overall costs of the transmission system and levy it on all users.

Ireland would likely benefit from further investment in interconnection with foreign electricity markets over the coming decade. While, to date, all investment has been designed to link Ireland and GB, the uncertainties about future GB plans on energy policy makes enhanced interconnection to France, albeit at higher cost, a possible option that policymakers should consider.

Provided that there is adequate use of interconnectors they should be paid for by fees proportional to the traffic through the interconnector.

### 3.2 UK POLICY – RENEWABLES POLICY

The UK approach to meeting its obligations on renewables under EU law has proved very expensive. They have used a mechanism to subsidise investment (Renewables Obligation Certificates, ROCs), which has added substantially to consumers' bills. The UK is now moving to a cheaper mechanism of feed in tariffs (Department of Energy and Climate Change 2012). Feed-in-tariffs provide a price guarantee to renewable generators for a certain number of years, typically 15 to 20. In practice this has been cheaper than using quantity-based standards (European Commission, 2008c), although why this should be the case is unclear from a theoretical perspective (Schmalensee, 2012). (The German government is also moving to reduce the large subsidy for new renewable.) In addition, in the case of the UK, the decision has been made to favour much more expensive offshore wind investment over onshore because investment in onshore wind farms is likely to be opposed by the local population. This has inflated the potential cost of meeting the UK target for renewable in 2020. Allowing for different subsidies for different technologies is akin to picking winners and can lead to large overall costs of the policy.

As mentioned above, the UK policy on renewables has proved very costly, prompting increasing opposition from final consumers. While, so far, the UK government remains committed to its policy, there must be some uncertainty as to whether this commitment will persist till the end of the decade. The fact that the policy is an unnecessarily expensive way of reducing greenhouse gas emissions weakens the case for continuing it. Also the decision by the EU to move away from national renewables targets after 2020 will raise questions as to the wisdom of pursuing a policy which will be superseded by a different approach in a few years.

Provided that the UK remains committed to achieving its renewable target for 2020, the high cost of delivering renewable electricity in GB could offer an opportunity for investors in Ireland to fill the gap. If additional electricity were generated from onshore wind in Ireland, it could potentially be exported to GB at a lower cost than generating it from offshore wind in the UK. However, investors would need to have access to the UK incentives. Also the Irish authorities would need to be assured that no costs would accrue to Irish consumers. There would also need to be compensation for social and environmental costs that would arise from the investment: committing this renewable electricity to the UK would preclude its use (or the use of the sites) to meet a further major increase in Ireland's renewables obligation. While such an increase may seem unlikely, forgoing the "option value" of such renewable electricity would also represent a potential cost to Ireland. However, provided that these costs were adequately



remunerated, this could prove a lower cost solution for the UK authorities than the alternatives, while providing some gain for Irish producers and taxpayers.

The major concern for both investors in Ireland and the Irish authorities would be that no expenditure should be undertaken unless there is a clearly enforceable contract with the UK authorities. Investors need to be protected against the possibility of a future change in UK policy which would see the UK adopting more cost-effective measures to reduce greenhouse gas emissions.

In March 2014, the discussions on this option stalled, apparently because of UK reluctance to commit to providing the necessary subsidies to generators in Ireland. Such reluctance is costly for the UK if it means larger subsidies will have to be paid to UK producers. However, a recent judgement of the European Court has recognised the right of national governments to restrict access to renewable subsidies to firms located within their jurisdiction.<sup>20</sup>

Developing EU wide trade in renewable energy could be beneficial, both for potential Irish producers and also for GB consumers.

### 3.2.1 UK Policy – Carbon Price Floor

In the UK the failure of existing EU policy on climate change, reflected in the very low carbon price, has been recognised and the government has put in place a domestic remedy, a carbon price floor. This carbon price floor is significant: it sets a minimum price for carbon and if the EU price falls below the threshold a domestic levy/tax is applied to keep the carbon price at the desired level. It was originally set in 2013 at a much higher level than the current EU price and the carbon floor, with the plan to raise it to a reasonably high level over time.<sup>21</sup> The effect of this price floor will be to reduce emissions in the UK and significantly raise the price of electricity in the UK. However, because the EU emissions limit will remain unchanged, there will be no effect on EU or global emissions – thus it will have no effect on climate change. In raising the cost of electricity, the UK will become marginally less competitive on world markets while the price of emissions in the EU, and hence competitiveness elsewhere in the EU, will be marginally improved (because the UK will use less permits, leaving more for the rest of the EU). Thus there are significant costs for the UK from such a policy.

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<sup>20</sup> <http://www.energypost.eu/eu-court-upholds-national-renewable-subsidy-schemes-surprise-decision/>

<sup>21</sup> However, since the introduction of the floor the commitment to increase it over time has been withdrawn.

As discussed earlier, if this policy were implemented at an EU level it would ensure a significant reduction in total EU emissions over time, irrespective of the underlying economic conditions. It would also make planning much easier for investors as it would provide much greater certainty about returns on carbon saving technologies. As a result, it would be likely to significantly reduce the cost of capital for investors due to the reduced risk. In turn, the cost of reducing emissions using this mechanism would be lower than where the price was uncertain, with commensurate benefits for consumers (see Box A). It would also ensure that there would be no loss of competitiveness for firms in one EU country relative to the position of competitors elsewhere in the EU. There would, of course, be a loss of competitiveness relative to any part of the rest of the world that does not take action on global warming. As the loss of EU competitiveness is inevitable if the EU takes effective action to curb greenhouse gas emissions, by minimising the costs for investors of undertaking the necessary action, it would also minimise the cost for EU consumers and producers.

While the UK can only impose a carbon floor for electricity generation in the UK, this policy change may well have a significant impact on Ireland. So far, Northern Ireland has been exempted from the carbon floor. Curtis, Di Cosmo and Deane (2014) show that, if the carbon floor were also implemented in Northern Ireland, it would impose significant costs on consumers in the Republic of Ireland, with part of this additional cost arising in the form of payments by Irish consumers to the Treasury in the UK. Under these circumstances the best option might well be to impose a carbon price floor in Ireland as well as in the UK – then at least the additional revenue paid by consumers would go to the Irish government.

However, even if the UK carbon floor is confined to Great Britain it still has important implications for policy in Ireland. While under the current level of interconnection between the two electricity systems in GB and Ireland, prices differ significantly in the two markets, major new interconnection could change this situation. The more interconnection there is between the two systems the greater will be the degree of price convergence (Malaguzzi Valeri, 2009).

As interconnection between the two systems increases, given the size of the GB market, GB will end up as the price setter on the joint market. Under these circumstances, a high carbon price floor in GB would translate into a much higher price for electricity in GB. The associated price increase in Ireland would adversely affect consumers but it would greatly increase the profitability of producers in Ireland, who would benefit from higher prices without having to pay

the carbon floor price. New generators would also be incentivised to establish in Ireland and export to GB, using expensive interconnection. This would be a very undesirable locational signal, potentially resulting in unnecessary additional costs for all electricity users arising from the need to finance additional interconnection.

Under these circumstances the best solution would probably be for Ireland to impose a carbon price floor similar to that in GB. This would transfer the windfall gains that would accrue to producers in Ireland to the government (who could redistribute it among consumers) and it would also ensure that more appropriate signals were given in the market on where best to locate new generation. However, with the limited amount of interconnection currently available, the effects on Irish prices of the UK carbon floor may well be limited, obviating the need for immediate policy action in Ireland.

While we have concentrated here on the implications of a carbon price floor in GB for the isolated Irish and GB electricity markets, a continuation of this GB policy would have implications for the interaction of the GB electricity market with that of the rest of North Western Europe. If a very large gap opened up between the price of carbon in GB and in the rest of North Western Europe as a result of the price floor, there would be a strong incentive to generate electricity in the rest of Europe rather than in GB. As in the case of Ireland, discussed above, relative to the even larger EU market, the price in the small (relatively) GB market would tend to be dominated by that in the rest of Europe. Once again the main constraint on price convergence between GB and the rest of the EU would be the level of interconnection between GB and the rest of Europe. With a big enough price difference it could be profitable to build new interconnection to exploit the arbitrage opportunities.

However, before such a trend developed the UK government would be likely to modify its policy, avoiding such an inefficient outcome. In turn, potential investors in new interconnection would know that the UK government would be likely to react to reduce the price differential to a level that made such investment no longer worthwhile. Nonetheless, the presence of a different regime in the rest of Europe would tend to place some long-term constraints on UK policy on a carbon floor.

With extensive interconnection between Ireland and the GB market, the presence of a carbon floor in the GB market will exert an influence on prices in Ireland. This will tend to transfer resources from consumers (household and

industrial) in Ireland to producers in Ireland, as Irish prices would rise. This transfer of resources to producers would be in the nature of a windfall gain. Under these circumstances it would probably be better if the Irish government imposed a similar carbon floor in Ireland. This could add further to prices in Ireland but, in this case, all of the transfer of resources would go from the consumer to the government, who could then return it to the household sector through other fiscal measures. If a carbon floor were introduced in the North of Ireland then it would be important that a similar floor was imposed in Ireland to avoid a substantial transfer of resources from Irish consumers to the UK Treasury.

### 3.2.2 UK Policy – Possible EU Exit

A major strategic risk for Ireland is that the UK might exit the EU later in the decade. The political implications of such a move by the UK could be even more important than the economic implications. Nonetheless, the potential effects on the energy sector could also be very serious.

Currently, it is very uncertain whether the UK will go ahead and hold a referendum on this issue. Further it is uncertain what the terms of such a referendum would be. Nonetheless, there is a real risk that the UK could vote to leave the EU even if the major political parties recommended otherwise. Because UK exit is a possibility, albeit not very strong, and because it would have major consequences for the energy sector if it occurred, it is a possibility that should be factored into all decisions on energy policy in Ireland. Here we highlight a small number of possible effects. A full discussion of this issue would require much more research.

Because a solution involving associate membership is unlikely to be acceptable to the UK, exit from the EU could well see the UK being subject to the common external tariff. This would require a customs border to be put in place between the UK and Ireland with tariffs, albeit small, possibly being applied to trade. It is not clear how this would affect the SEM.

The UK would no longer be subject to EU law. This could lead to uncertainty in many areas of energy policy. For example, Ireland currently relies on EU regulatory measures to deal with a possible crisis situation in the case of a gas or oil shortage. Current provisions of EU law provide for an equitable sharing of resources under such circumstances, facilitating coordinated emergency planning and resolution of any disputes among member states. If the UK left the EU it would no longer be subject to these provisions. Ireland would then have to

consider how best to provide protection from very unlikely, but potentially catastrophic outcomes.

If the UK left the EU, it would no longer be subject to EU rules on climate change policy and renewables. This would raise the possibility that the UK could change its current policies – where they are likely to impose a high cost on the domestic economy to produce the necessary investment in renewables. It is difficult to predict how UK energy policy might develop if it were no longer subject to EU law. In turn, because all of our gas and electricity interconnection is to the UK it is very difficult to predict what the implications would be for Ireland.

What this uncertainty suggests is that energy policy in the longer term should strive to reduce Ireland's dependence on its interconnection to the UK and place more emphasis on interconnection to the wider EU market. However, implementing such a strategy could itself prove very expensive so that the appropriate course of action is far from clear. Obviously, the best solution is if the UK makes a long-term commitment to its EU membership.

Any strategy by the Irish authorities that would help reconcile the UK to its EU partners would be important, given the very serious consequences for Ireland of UK exit. Until the UK decides on its future membership of the EU, all major energy policy decisions in Ireland need to be tested against the effects of differing outcomes on UK membership of the EU. This also applies to investment decisions, where future reliance on EU law may not provide adequate protection for Irish interests.

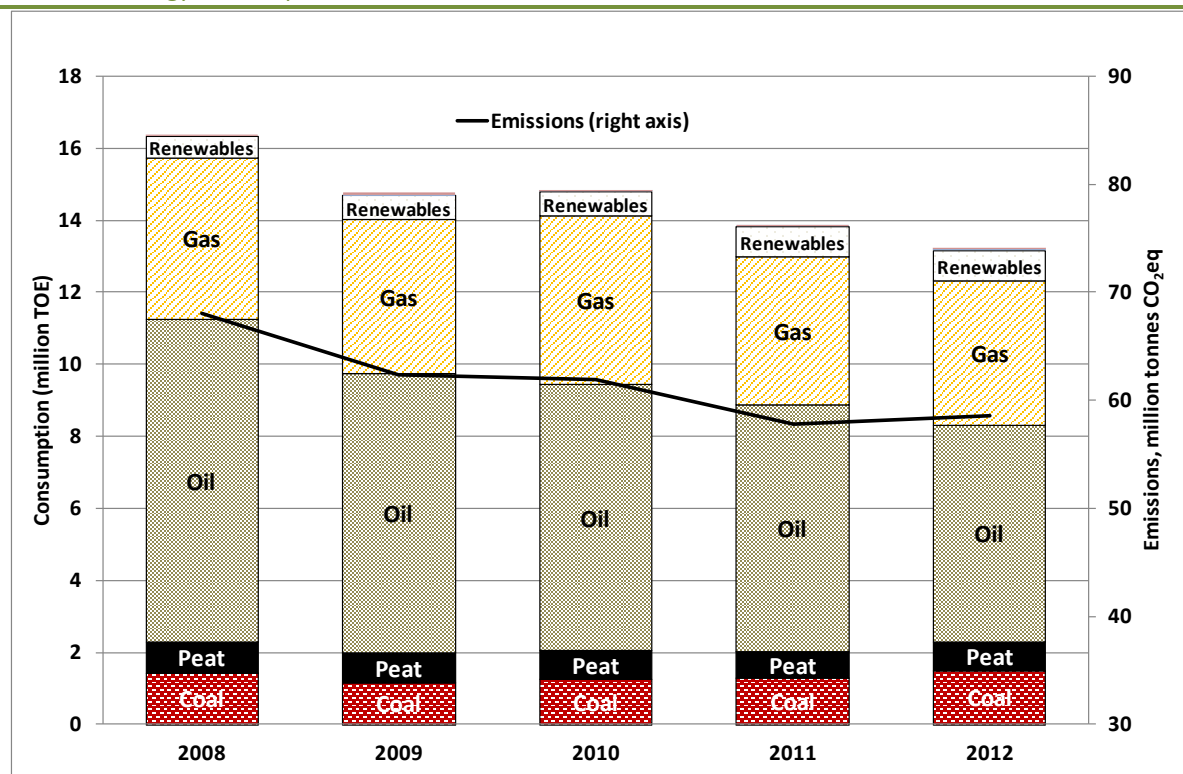


# Chapter 4

## Supply Side

The main goals of energy policy are to provide safe, reliable, affordable and clean energy. This section addresses some of the challenges in ensuring an efficient provision of energy to the economy. It first focuses on security of supply for natural gas, then discusses the need to charge appropriately for transmission and distribution infrastructure for both natural gas and electricity. Finally, it addresses more complex issues arising in electricity markets, in part related to the successful penetration of large-scale wind generation.

**FIGURE 2** Energy Consumption and Emissions in Ireland, 2008-2012



Source: SEAI: Statistics Portal and Irish Environmental Protection Agency.

As a background to the challenges in energy supply Figure 2 shows the share of primary energy consumption in Ireland by fuel between 2008 and 2012 and economy-wide emissions of greenhouse gases. Primary energy consumption measures the amount of primary fuels used in the country. It includes fuel used for the generation of electricity, but not direct consumption of electricity. The

recession has reduced the consumption of oil significantly, with a higher than proportional effect on emissions, due to its relatively high carbon content.

Despite some indigenous sources, Ireland relies on imports for most of its natural gas (in 2012 natural gas imports accounted for 95 per cent of Ireland's needs - see SEAI, 2013a). There are no indigenous sources of oil or coal. Peat is the only non-imported fuel. This highlights the dependence of Ireland on imports of energy. The dependence on imports, on its own, has no implications for security of supply. However, if the supply comes from only one or a strictly limited number of sources, this does give rise to concerns that the economy could be seriously disrupted through an interruption in supply from a single key source.

#### 4.1 IRELAND – NATURAL GAS MARKETS

Natural gas met 30 per cent of total primary energy demand and produced 49 per cent of Ireland's electricity in 2012. In 2011 gas-fired generators accounted for 55 per cent of electricity generation (SEAI, 2013a). The number of natural gas customers in Ireland is increasing, especially in the residential sector encouraged by increased availability, competitive prices and the reputation of gas as the cleanest fossil fuel available (Leahy *et al.*, 2012). In 2012 alone, total final demand for natural gas increased by 8.1 per cent.<sup>22</sup> Electricity generation from natural gas fell by 7.7 per cent in the same year, due to the relatively low prices of coal and peat (SEAI, 2013b). Overall, natural gas consumption fell by 2.5 per cent in 2012. The dependence of Ireland on natural gas, especially in the electricity sector, is high by EU standards. While it has allowed Ireland to substantially reduce greenhouse gas emissions, it leaves Ireland very exposed to variations in gas prices and, related to this, to any disruption in gas supplies.

There are two major gas policy issues for Ireland: the delivery of gas to consumers at minimum cost and security of supply.

With a British Isles gas market, of which Ireland is a part, and a developing EU gas market, the price of the gas itself is set by competitive forces – something that Irish policy cannot influence. However, transporting the gas to consumers from where it is sourced is affected by how the necessary infrastructure is financed

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<sup>22</sup> Final Energy demand or Total Final Consumption is total primary energy demand less the quantities of energy required to transform primary sources such as crude oil and other fossil fuels into forms suitable for end use consumers such as refined oils, electricity, patent fuels, etc. (SEAI, 2013b).



and regulated. Because of the very high dependence on gas, a secure gas supply is of vital national interest. Recent turmoil in Ukraine has highlighted the importance of physical security of supply and underscored the current dependency of European supplies on Russia.

The issue of security is not just about physical security of gas supplies, though that is of course vital, but it is also about the availability of the gas at a reasonable price. Because there is an EU-wide market in gas, that market is very important in setting the wholesale price for gas.

#### 4.1.1 Pricing Infrastructure

As discussed later, in the early 2000s a second gas interconnector was built between Ireland and Scotland to provide increased capacity and, most important, to enhance security of supply. These interconnectors between Ireland and Great Britain have been paid for by way of a guarantee by the state that their costs can be recouped from consumers. Consumers have carried all the risk of the investment and are committed to paying the full cost of this infrastructure. In a very real sense the consumers of Ireland “own” the gas transmission infrastructure, including the onshore transmission, because they are paying for it. As owners, who are committed to paying the full cost of the infrastructure, consumers are entitled to see it used in a manner that minimises the cost of their gas supply, consistent with security of supply.

Under these circumstances the correct approach to charging for this infrastructure is to treat the gas interconnectors as part of the gas transmission network and to recover the capital costs via an increase in the use of system charge levied on all gas consumed by the owners – the consumers of Ireland. Because no additional interconnectors are likely to be needed, the appropriate charge for use of the interconnectors is the short-run marginal cost of using those interconnectors. This would include the cost of pumping the gas through the interconnectors until it reaches the onshore transmission system, as well as any wear and tear resulting from the use of the infrastructure. It should not include payment for the capital cost of the interconnectors. Obviously, where other suppliers deliver gas directly to the onshore transmission system (Corrib) they would not have to pay for the cost of pumping gas through the interconnectors.

If the charge for use of the interconnectors was only equal to the short-run marginal cost of using the pipelines the revenue would not be sufficient to remunerate the owners of the pipeline. As set out in the CER, 2011, the current tariff is calibrated to give to the interconnector owner final revenue of €50 million

a year which permits the full recovery of the costs of the pipelines over a reasonable period. Until 2012 this revenue was collected through a charge per unit of gas passing through the pipeline as well as a fixed capacity charge.

One option would be to treat the interconnectors as separate infrastructure from the national transmission system (FitzGerald and Di Cosmo, 2011). However, as argued above, the gas transmission infrastructure is there to ensure that gas (and electricity) users have a safe and secure supply of gas on the island. The security benefits of the infrastructure accrue to all gas users. With the onshore infrastructure, a common use of system charge is deemed appropriate, as all users benefit from its existence. This argues strongly for treating the gas interconnectors as part of the gas transmission network and charging for it in the same way as we charge for the existing transmission system.

The price of gas in Ireland is set on the market as the GB price plus the cost of transmission. Under the arrangements put in place in the last decade, as domestic supply rises, the cost of transmission per unit of gas imported through the pipelines would also rise because the volume passing through the pipeline will fall. In the limit, once supply from domestic sources equals demand, the price of transmission per unit of gas would be infinite. In turn, this would imply that the price of gas for consumers would rise as more and more gas was sourced from domestic sources because the Irish price would be the GB price plus the cost of transmission. The domestic price would never become “infinite”. However, it would continue to rise until domestic demand was choked off through the rising domestic gas price, to bring domestic demand into line with domestic supply. A further limit on the price would be that the owner of the pipeline, while unable to cover its costs, might act strategically to trade in gas itself, garnering some revenue.

Meanwhile the regulator would have to ensure that the stranded costs were serviced in some other manner. It would clearly be unacceptable to push these stranded costs onto the taxpayer. To the extent that they would have to be covered by the consumer this argues for treating the interconnectors as part of the regulated asset base and charging a common charge to all users of that transmission infrastructure.

In the light of this analysis, FitzGerald and Di Cosmo (2011) recommended treating the gas interconnectors as part of the essential gas infrastructure on the island and recovering the capital costs through the use of system charge paid by all users. This would secure the guaranteed revenue to cover the historic costs of

providing security of supply and it would ensure that the price facing domestic consumers would be invariant as to the quantity of gas sourced domestically. This approach has informed the subsequent decisions of the regulator.

The Commission for Energy Regulation (CER) addressed this issue in 2012 and 2013 (CER, 2012, 2013). It stated that the cost of the natural gas infrastructure, including the interconnector, needs to be recovered, but should not be paid for in the form of an increase in the per unit entry tariff. Tariffs at each entry point to the Irish network will be determined on a long-run marginal cost basis. To counteract the drop in capacity bookings, the CER ruled that, starting in October 2013, exit capacity could not be transferred.<sup>23</sup> In February 2014 it found that the regulatory change had increased the revenues to the natural gas network sufficiently. It therefore did not implement its second proposal, which was to eliminate within-day purchases of short-run capacity (CER, 2014a). The change in regulation undoubtedly increases the costs of natural gas powered generators that face a more variable residual demand, due to the combination of higher gas prices relative to coal, low carbon prices, higher penetration of renewables and increased electricity imports through the interconnectors.

However, there are some questions over the actual implementation of this in practise. Currently, electricity users have to pay in advance for likely usage of the system. Because of the variability of supply, especially from wind generators, and uncertainty about demand, it can be difficult to be certain how much gas will be needed. Yet electricity generators still have to book capacity in advance and suffer possible unnecessary costs if the capacity is unused. Under the current regime this uncertainty adds to the costs for generators. It is also probably a bigger issue for owners of a single generator rather than owners of a portfolio of generators. In turn, by adding to the costs of generators it can add to the long-run cost of operating the system, with negative implications for consumers.

If the uncertainty about future gas needs imposed significant costs on the owners of the transmission network, then such a charging mechanism would be appropriate – the risk and associated costs would be transferred to the agent in the best position to manage that risk. However, with considerable excess capacity

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<sup>23</sup> Energy users contract to take specified volumes of gas out of the pipeline system in Ireland – the exit capacity.

in the system, and storage in the gas pipeline itself,<sup>24</sup> it is hard to see that there is any major cost for the operator of the system from variation in gas usage.

Under these circumstances it might be more appropriate to charge for gas transmitted through the transmission system (including the interconnectors) on a per unit basis. The per unit charge for the coming year would be estimated based on forecast gas usage. Then, if revenue is excessive in a particular year, the surplus revenue would be used to reduce charges in the following year and losses in a particular year would also be recouped by varying charges in the subsequent year. Such a regime would seem likely to reduce the uncertainty (and hence the costs) for electricity generators, while at the same time not significantly increasing the costs of the transmission system operator.

The Irish gas interconnection infrastructure should be treated as part of the transmission infrastructure in Ireland and priced accordingly. The pricing of this infrastructure should not be used to further other policy objectives. If necessary, other policy tools can be used to encourage measures that would enhance security.

#### 4.1.2 Security of Supply

A major gas outage would have serious implications for the Irish economy. Even with Ireland's domestic source of natural gas, 92 per cent of the country's gas supply was imported in 2008, (SEAI, 2009) increasing to 95 per cent by 2012 (SEAI, 2013a). Production of indigenous gas decreased by 90 per cent over the period 1990 to 2012, with the exception of a 7.4 per cent increase occurring in 2012. This decrease in indigenous production is reflected in the increase in dependence on GB for imported energy (SEAI, 2013b). At the same time GB itself has changed from being a net exporter of gas to being a net importer. Thus, the British Isles market is gradually becoming integrated into the wider EU gas market and, in the long run, any shock to EU gas supply will have knock-on effects on Ireland.

Gas supplies are of crucial importance to Ireland because gas plays a central role in electricity generation. Because of this, any interruption to supply could have

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<sup>24</sup> By varying the pressure within the pipeline within design limits the quantity of gas in the pipeline can be varied. Thus a marginal reduction in pressure in the pipeline, through a release of more gas than planned onto the Irish market, can readily accommodate an unexpected increase in demand.

very serious consequences. Nearly all of the gas used in Ireland comes through the interconnectors with the UK. There are three under-sea pipelines but only one onshore pipeline in Scotland carrying all the gas for the island of Ireland. Clearly, any problem with the one onshore pipeline in Britain would be very serious for Ireland. Experience elsewhere suggests that such problems can generally be repaired relatively rapidly onshore. Nonetheless, there remain concerns about dependence on this single piece of infrastructure.

Whatever about the security of the onshore pipe, any break in an offshore pipe would take much longer to fix. After the first undersea interconnector was built in 1993, a second interconnector was completed in 2002 in order to fulfil both the obligations imposed by the EU Regulation on Security of Gas Supply and also to protect Ireland against any risk of service disruptions through a fault in the existing undersea pipeline. The second interconnector replicates the maximum capacity of the first interconnector (measured as 17 million cubic meters/day) and provides an additional capacity of 6 million cubic meters/day to take into account the rise in the gas demand expected since the beginning of 2000s.

As a result of the building of the second pipeline there is greatly enhanced security, not just for those who source their gas from GB directly through the pipelines, but also for all users of gas, from whatever source, and all users of electricity. With the building of the North-South pipeline the benefits of security of supply were further enhanced for consumers both North and South.

This still left a vulnerability to damage to the single onshore pipeline in GB. However, with the advent of Corrib, Ireland will have two alternative sources of supply of gas for the coming decade. While Corrib will never be able to supply all of Ireland's needs, it is likely to be able to meet the needs of the electricity sector until at least 2020. Thus Ireland's vulnerability to a possible very low probability event (damage to the onshore pipeline in GB which would take more than a week to repair) will have been eliminated for the current decade. There is, as a result, no reason for consumers to pay for an additional premium for security of supply over the next few years.

The Corrib gas field is currently being developed as a new source of indigenous gas and is expected to supply slightly over 60 per cent of Irish demand when in operation, but only for about six years (Leahy *et al.*, 2012). Thereafter, over the following decade, the gas supply from this source will gradually fall off. Due to continued delays, the Corrib gas field will not produce the first gas flow till 2015.

Ireland's increasing dependence on GB for natural gas imports has put security of supply and cost of transmission at the centre of energy policy. Security of supply can be defined as "...an uninterrupted flow of energy to meet demand in an environmental sustainable manner and at a price level that does not disrupt the course of the economy" (Damigos *et al.*, 2009).

In a 2009 report (CER, 2009), the CER stated that at the end of 2005 the average number of days of gas storage in Ireland was 11 days whereas for the EU-15 it was on average 52. Thus a prolonged interruption of supplies could not be met from storage.

The economic cost of a natural gas outage measures the consequences of the unavailability of natural gas for heating, electricity and industrial production. This can be done by measuring lost consumer surplus in the residential sector, the cost of lost electricity in all sectors (by estimating the value of lost load) and lost VAT on the sale of gas and electricity. Lyons and Morgenroth (2013) estimate the daily economic cost for Ireland of a natural gas outage in 2008 as ranging from €350 million to €640 million with the loss in electricity accounting for an estimated 80 per cent of the total cost. The estimated cost varies significantly with demand, the time of year and day of the week, and how capacity is managed. Such a loss, if sustained over many days, would result in a truly dramatic loss of GNP, dwarfing the cost of the recent economic crisis. Hence, even if this is a very low probability event, action to render it even less likely is of considerable national importance.

Demand for natural gas in the residential sector is inelastic, changing only because of the weather; demand for natural gas in electricity generation is determined by many more factors, including the availability of alternative fuels and the adoption of new technologies. Even with increased wind generation, there is still a need for predictable fossil fuel plants to maintain the electricity system's reliability. When wind dies down, thermal plants must be available to pick up the slack. Demand for natural gas as a means of electricity generation will, however, fluctuate more often and less predictably, with implications for the profitability of natural gas fuelled generators (Di Cosmo and Malaguzzi Valeri, 2014).

Leahy and Tol (2011) examine the sectoral incidence of electricity outages and how this would impact on costs. The authors emphasise that the costs associated with an interruption to electricity supply are likely to be higher for residential customers than for businesses and, therefore, supplies to industrial users should

be limited first if there is a shortage (as is the practice in the event of a natural gas interruption, on foot of EU Regulation 994). Current electricity outage planning measures, on the other hand, give priority to industrial users and would propose to ration households' electricity first. The decision as to which sector will be subject to rationing should depend on the day and time at which the shortage occurs. Leahy and Tol's (2011) estimates only address short interruptions. Longer interruption may be disproportionately damaging to some sectors.

Leahy *et al.* (2012) extend the analysis of the losses due to a natural gas shortage for periods of 1 to 90 days in winter and summer of 2008. Investment in a strategic storage facility would allow natural gas to be available in times of persistent market tightness. Currently, there is only a small amount of natural gas storage in Ireland at Kinsale (and also through over-pressurisation of the pipeline). It is able to provide around 3 per cent of annual demand and possibly less in the coming years (Leahy *et al.*, 2012). In addition, each gas fired electricity generator is required to hold between one and two weeks supply of gas diesel which can be used, at a significant cost, to fire the generators should gas not be available. However, the authors conclude that, due to Ireland's location, interconnection with Britain is the only practical solution to ensure long-term security. Ireland's changing portfolio of natural gas supply must be taken into consideration when deciding on a large investment such as an extra interconnection or shale gas infrastructure. As the supply for the Corrib field begins to run down towards the end of the decade it will then be appropriate to consider how security of supply for consumers can best be ensured after 2020 at minimum cost.

The failure to bring onshore the gas from the Corrib field has left the people of Ireland at risk from any major disruption to gas supply over the last decade. Fortunately, no such interruption occurred. As discussed above, if prolonged, a gas disruption could prove catastrophic for the Irish economy and wider social welfare. While this would be a very low probability event, the failure to bring Corrib onshore posed unnecessary risks for Ireland. In addition, the excessively expensive process that has been required to bring the gas onshore will result in substantial loss of future tax revenue for the Irish government – an additional cost as a result of the long-drawn out process of bringing the field to production.

Because of the vital importance to Ireland of the security of gas supply, planning needs to begin now for a strategy to deal with the gradual run down in gas supply from Corrib in the early years of the next decade. The best outcome would be the discovery and development of another gas field to replace Corrib when it runs down. As well as providing additional tax and royalty revenue to the government

it would have a major value in enhancing the security of the nation's gas supply. Thereafter, additional fields would not confer a significant security benefit. Hence, it might be appropriate to offer more favourable terms for the first firm to deliver an alternative substantial supply of gas to the Irish economy because of the economic externality – enhanced security. Once security of supply is assured the state's interests in maximising future revenue from any additional finds can be pursued.

For security of supply reasons it is very important that the Corrib gas field is brought into production as soon as possible. Thereafter, it will be important to develop a strategy to replace Corrib once the field begins to run down in the early years of the next decade.

#### 4.1.3 Gas Storage

Given the importance of the supply of natural gas to the Irish economy, discussed above, there may be significant value to having increased storage of gas on the island of Ireland. Already there is a small amount of storage available at Kinsale; there is also a very small amount of storage available within the transmission system, and gas fired generators hold a number of days supply of gas oil to tide them over an emergency. However, across Europe higher volumes of storage are normal.

Enhanced storage would have a potential value in smoothing seasonal price variation. Given the magnitude of this variation there is considerable revenue to be made from buying gas in the summer and storing it for sale in the winter. However, if gas storage were used to smooth seasonal price fluctuations it would not necessarily be compatible with providing security against a loss of gas supply. For example, gas storage operated on a seasonal basis would empty by the early spring, as gas was sold from storage at high winter prices. Thus, any interruption to gas supply at that point would not be backed up by stored gas.

There are some locations that are potentially suitable for gas storage, especially in Northern Ireland. However, if such storage were to be used for strategic purposes on a long-term basis, the value it would confer would be related to the expected cost and the probability of a longer-term gas outage. Storage for such a purpose would only be feasible if the regulatory authorities believed it had an economic value greater than the cost of development and if the regulator were prepared to impose suitable additional charges on gas users to fund the storage.



There are many different ways of approaching the problem of gas security. These include storage in different forms, reducing overall dependence on gas or developing a Liquefied Natural Gas (LNG) terminal or diversifying away from gas altogether. It may be difficult to choose from a range of diverse options. One possible approach would be to charge a small premium on all gas used and to use it to reward technologies or solutions that enhanced gas security. Then market operators could choose whether they could make sufficient profit from this premium to fund a particular technology that enhanced security.

## 4.2 THE IRISH ELECTRICITY MARKET

The Single Electricity Market (SEM), which was established on the island in 2007, has operated successfully since that date. It has provided a reliable supply, and the wholesale market has operated as expected. The capacity payments regime has ensured an adequate supply of new investment and the market has also absorbed the very big increase in variable electricity supply from renewables without any apparent problems for consumers. There is currently some overcapacity, much of it due to the recession, which caused a sizeable drop in electricity demanded after 2008. In 2008, electricity demand for 2012 (in the medium growth scenario) was forecast to be about 20 per cent larger than what it actually turned out to be.<sup>25</sup>

The wholesale market is transparent and it was designed to minimise the risk of one company exerting market power. It has apparently succeeded in this objective (Gorecki, 2013). One aspect of the market that has not worked well has been the provisions for trade in electricity with the neighbouring GB market. McInerney and Bunn (2013) have shown that today the flows across the interconnectors to GB are less than the optimal amount and at times go from the high cost to the low cost jurisdiction. This implies higher costs than necessary for consumers in Ireland and / or in GB.

The main domestic challenges that the Single Electricity Market (SEM) on the island now faces are maintaining and possibly increasing security of supply, accommodating increasing generation from intermittent sources and meeting emissions targets for greenhouse gases efficiently. However, the market also

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<sup>25</sup> SONI (2008) and EirGrid (2008) provide the expected demand for the medium growth forecast. We base actual outturn for 2012 on EirGrid and SONI historic electricity demand data. Note that the overall weather was similar in 2008 and 2012, based on total heating degree days information for Ireland from Eurostat.

needs to change to meet the criteria that underpin the EU Target Model (Gorecki, 2011), facilitating trade across borders. These latter reforms, needed to allow cross border trading, should also deal with the problems in the usage of the existing interconnectors. As discussed earlier, decisions also have to be made on how to reinforce the transmission and distribution infrastructure and invest in new generating plant.

This section starts by considering the CER proposals on how the SEM might be changed to meet the rules on EU trading. One of the main challenges is integrating the SEM with neighbouring electricity markets. The proposed new market is therefore referred to as Integrated SEM or I-SEM. These changes will have very important implications for the operation of the market in the future. Then we discuss policy on the replacement of the largest generating plant in the SEM, the coal-fired Moneypoint station. This issue is important, not just because of the need to replace the aging generation plant, but also because the choice of replacement may have long-term implications for greenhouse gas emissions and for Ireland's dependence on gas. This section then discusses some of the issues surrounding transmission reinforcement and, finally, we examine the impact of increasing wind generation on the electricity system and on the cost of electricity for consumers.

#### **4.2.1 Redesign of the Single Electricity Market**

Gorecki (2013) points out that the problems facing the SEM today do not differ substantially from those present at the outset of the market in 2007. There is still a desire to deliver electricity efficiently while successfully limiting market power, encouraging entry, and ensuring adequate capacity. The main change since 2007 has been the increased penetration of renewables, especially wind.

Inroads have been made in controlling market power by making the incumbents (ESB in Ireland and Viridian in Northern Ireland) offer contracts for differences and forcing ESB to divest some of its assets. Entry is facilitated by maintaining regulatory credibility, the provision of a capacity payments regime, allowing new generators to enter without having to assemble a client base (thanks to the characteristics of the pool) and dispatching generators based on merit order, since the most recent generators are also likely to be more efficient. Allowing new generators to access the electricity grid easily is vital. In Ireland's case the grid is owned by ESB, but managed by the independent agency EirGrid to ensure no discrimination in grid access.

The following issues remain crucial in moving to an electricity market that is consistent with the EU Target Model:

1. Market power could decrease if interconnection is expanded. However, there is growing concern that the EU electricity market as a whole is becoming more concentrated (Meeus, 2011). Deane *et al.* (2014) suggest that in GB market power has resulted in electricity costs being substantially higher for households than would be the case under perfect competition.<sup>26</sup> Thus, whatever market structure develops in Europe, action will be needed to prevent the abuse of market power. Clearly, if Ireland were part of the GB market today, households would face the same excessive retail margin that GB customers are currently experiencing. As discussed below, there are concerns that the current suggested changes to the SEM could actually increase the opportunity for firms to exploit market power, to the disadvantage of consumers.
2. Even though there is excess capacity in the Irish electricity system at the moment, it could be argued that it is a short-run situation, mostly due to the recession. The closest market to Ireland, that of Great Britain, is facing a generation shortage in the medium term, so encouraging new entry remains important. This argues for a continuing mechanism for incentivising the provision of adequate capacity.
3. Ease of market access remains vital.
4. With the current design, large amounts of wind can lead to marginal prices of electricity frequently going to zero, potentially reducing the incentives for new thermal generation to invest, even though thermal generation is necessary to maintain a secure system.

As a result of these concerns, when considering how best to implement the EU Target Model, tradeoffs will arise. On the one hand, options that are closer to the current configuration of the SEM will avoid large market changes: given that evaluations of the SEM indicate that it has worked fairly well (Gorecki, 2013) this means that there is an advantage to maintaining key features of that market. Market participants' learning curve would therefore be fairly flat. On the other hand, the option closest to the current SEM (labelled as 'gross pool with net settlement market') essentially uses 'fixes' to adapt the current market to the Target Model. As discussed by the regulators (Utility Regulator and CER, 2014), coordination with European markets to determine the amount and direction of the interconnection flow is based on the day-ahead market, which might not be

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<sup>26</sup> This research shows a significantly lower margin charged to Irish households than in GB suggesting that the SEM has been more effective in dealing with issues of market power.

very liquid. It is therefore possible that interconnection flows in this option would not exploit the interconnection capacity efficiently.

In deciding how to develop the SEM to better integrate with the wider EU electricity market, an important issue is the transactions costs involved in developing the technology needed to underpin the new market. In countries such as Germany and the UK this may seem a trivial issue. However, the sums involved are largely independent of country size and, whereas for Germany €200 million may be a small price to pay for the technology needed to make a new market work, in the case of Ireland it would represent a significant addition to consumers' bills. For example, the technology needed to allow consumers to change electricity supplier was very expensive and the consumer benefits from switching are unlikely to ever recoup this investment. Thus, in making choices about how to modify the SEM, serious attention needs to be given to the costs of the change, not just for the administrators of the system, but for all the participants.

Avoiding abuses of market power should still be a central concern. There are basically two ways of doing so in the new Integrated Single Electricity Market (I-SEM) proposed by the CER: one is relying on the efficiency and fluidity of forward markets and the second is monitoring and controlling bids. A further possibility, reliance on competition law, might not be effective due to the length of time needed for cases to move through the courts.

The current CER proposals envisage an exclusive, but not a mandatory, day-ahead market. However, given the small size of the Irish electricity market, the limited number of players, and the structure of the retail market, it is hard to see how this market will be liquid. Of its nature it will be less transparent than the mandatory pool, which would make it very difficult to develop suitable bidding rules. If the necessary liquidity required to make the market work were to require major intervention by the regulator, this would raise questions about how useful the market would be in delivering an efficient allocation of resources.

The algorithm to be used in operating the proposed day-ahead market may not allow complex bids of the kind used in the SEM at present. This means that generators will need to play a more active role in structuring their bids in order to recover their discontinuous costs, such as start costs and no load costs. This may remove some of the downside risk from consumers, who currently pay generators for any start up and no load cost not covered by the marginal price payments, but it would mean that bids can no longer be required, under a

bidding code, to reflect marginal costs. Thus the monitoring of bids and detection of market power in such a market will prove more difficult.

Before coming to conclusions on how this proposed market will work, significant further research is required. This needs to identify whether the market is likely to deliver an efficient dispatch of the electricity system and of the interconnectors and whether it will deal adequately with the issue of market power. The proposed new market needs to work without requiring extremely complex intervention by the regulator.

In addition to the proposals on replacing the pool, the CER are proposing a new Capacity Remuneration Mechanism (CPM) to replace the current capacity payments system.

The proposed new market structure would mean that we would move from a price-based to a quantity-based mechanism for ensuring capacity, so that, in the new market, generators will choose *ex ante* whether to make their capacity available (at a contracted price). In the current market the capacity payment mechanism essentially provides a pool of money and it is divided between those generators that are available in each time period. Because the pool of funds is fixed and because there are a significant number of generating units, the effect of any one generator not being available, or pulling out, is not sufficient to raise the average payment to available generators by a large amount. Thus, there is no major incentive in the current system to try to game it.

The new proposed mechanism for capacity would involve firms bidding for financial contracts to provide capacity and the system operator would be required to contract ahead to ensure sufficient capacity would be available in future time periods. The total cost of the capacity mechanism would depend on the bids received from generators making up the capacity needed.

Because there is excess generating capacity available today the hope would be that the price for capacity would be bid down, reducing the overall cost of the mechanism. However, this does not take account of the market structure and the costs and incentives faced by the different players. There are clearly potential issues with market power in the proposed capacity mechanism (Cramton and Stoft, 2008, footnote 1).

The authorities contracting for future capacity face a huge cost if, in any one period, they do not have adequate capacity available and the lights go off (Leahy and Tol, 2011). Thus, they need to contract for adequate capacity even if the price is very high. This reflects the fact that the value of loss of load is exceptionally high. On the other hand, the generators face a much smaller cost if they fail to get a contract – they lose capacity payments for just one time period. Because the contracts would be offered on an annual basis the cost of failing to get a contract in any one year would be the loss of payment for capacity for a single year. The firm can always enter a new bid for the following year. This loss of payment for one year by a generator would be much less than the cost to society (and hence to the regulatory authorities) from the lights going off.

The number of owners of dispatchable generators is small in the Irish system.<sup>27</sup> While there is significant excess capacity on the system at least one owner of generation plant is often pivotal, i.e., necessary to maintain adequate capacity to keep the lights on during winter peaks. For this operator the optimal strategy would be to bid an exceptionally high price on all of its generation knowing that at least some of this generation would receive the price they bid. If this price were sufficiently high it would more than compensate for the failure to get a contract for the rest of the capacity. The other limited number of operators of generation plant would know what would be the optimal strategy for the leading player. In this case their preferred strategy would be to also bid high. While they might lose out to one of the other competitors in the first year, they could recoup their losses by appropriate bidding in subsequent years. Without collusion between the players, the most likely outcome of this process would be a gradual escalation of prices to levels well above that needed to adequately remunerate capacity.

There is the argument that the capacity auction cannot go to a high price as the possibility of new entrants bidding in will force incumbents to bid less than or equal to Cost of New Entrant (CONE). (This of course only holds if there is a large pool of potential suppliers ready to connect should their bids in the auction be accepted.) However the repeated nature of the auction means that the high clearing price is an unstable equilibrium; a new entrant will not enter at CONE, or even substantially above CONE, as the incumbents can bid low the following year and cause the price to collapse. A new entrant has more to lose from this low

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<sup>27</sup> It is also small in most other national electricity systems, including the GB system.

price than the incumbents and so the possibility of incumbents collapsing the price is credible.

What makes this proposed alternative mechanism for remunerating capacity so much more vulnerable to firms exerting market power is that there is no upper limit to the total pot of capacity payments. Also there is no easy way that a “bidding code” could be developed which would prevent gaming, as in the case of the current wholesale market. While the new mechanism might result in a fall in the total capacity payments under conditions of excess supply, it might be even more likely to lead to an increase in the cost of capacity payments. Under conditions of a shortage of capacity the risk of very high prices would be even greater.

A cursory review of the literature suggests that there is no obvious solution to the problem of market power and it may be very difficult to find a satisfactory solution to mitigate the problem. We consider here some solutions that might be put forward. However, as we indicate, in each case we feel that they would not work.

The largest player in the SEM, the ESB, could be required to bid a particular price. However, this would only result in everyone else bidding just below the ESB, with the ESB becoming the residual supplier of capacity. This might not be the most efficient solution. Also, it would effectively mean that the CER would be setting both the price and the quantity. This would be totally unsatisfactory – the CER would be left deciding the returns to individual generators without having any economic basis for the decision.

Another possibility is that the ESB generation portfolio could be broken up. However, we see a number of problems with this. Firstly, with up to four significant players rather than one dominant player, the result of the “game” could well be the same. Given the asymmetry of costs for the system operator and the players, and given the repeated nature of the game, the outcome could well be an equilibrium solution of really high prices. The size of the ESB’s portfolio is not, on its own, the problem. Secondly, with increased interconnection, other firms with portfolios of generation greater than the Irish market (and much greater than the ESB) could become players. In a British Isles context the ESB is a minnow. There is no way that the CER could force divestiture on companies, such

as EDF in GB, who have very large portfolios of generation relative to the size of the Irish market. However, there is ample evidence that the GB market suffers from the downside of use of market power by incumbents.<sup>28</sup> Thirdly, the evidence worldwide is that companies own portfolios of generators. This suggests that there may be economies of scale. While this portfolio behaviour may all be driven by a desire for market power, we suspect that there are real reasons for this behaviour – economies of scale exist. Forcing all players to be companies with a single generator would, as a result, raise the operating cost of the system.

If the market power issue is not effectively addressed in I-SEM, the new market structure could potentially result in higher prices for consumers. The short-term market is likely to deliver higher prices than the current wholesale market. Unless the capacity mechanism delivers a significantly lower cost, then the total cost would be higher for consumers. With market power it could be much higher. (Obviously any gains from better use of interconnection would have to be offset against higher costs from generation.) Thus, there is a danger that the proposed new market would make consumers worse off than today if the problems, identified here, are not addressed. This danger needs to be flagged and discussed publicly, not least with the EU.

Extensive research in the ESRI and elsewhere highlights how important the cost of capital is in such a capital intensive industry. As a result, there is a high cost to uncertainty of returns for investors, which raises financing costs. This cost must, in turn, be passed on to consumers. The importance of this was central to the decision to implement a capacity mechanism in the SEM. Recognition of the importance of this issue underpinned the decision to go for a Renewable Energy Feed-in-Tariff (REFIT) as a support mechanism for wind.<sup>29</sup> The work by Walsh *et al.* (2014) and others, such as Lyons *et al.* (2007) and Helm (2009), shows how important price uncertainty can be to investment decisions. Thus, the decision to move from a mechanism which deliberately produced fairly predictable returns to one that possibly produces highly variable returns is likely to result in higher capital costs for investors. In turn this must be passed on to consumers. To justify these significantly higher costs the new market structure must hold out the prospect of substantial gains elsewhere to offset these costs. It has not been shown that the current proposed market structure will achieve sufficient savings (possibly even delivering higher costs).

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<sup>28</sup> For example, Deane *et al.* (2015).

<sup>29</sup> Farrell, *et al.* (2013) and Devitt and Malaguzzi Valeri (2011).



In proceeding to change the market, the regulator's reputation is an important consideration. Until today the CER has developed a reputation for providing a stable playing field for all involved. We have seen how, elsewhere, frequent changes in market structure and arbitrary changes by governments (e.g., Germany) and regulatory authorities can raise the cost of capital.<sup>30</sup> It will be important that any change by the CER is not seen as arbitrary by either producers or consumers. While the EU rules provide a reason for changing, care needs to be taken that, whatever change is made, is robust in the future, and that Ireland's reputation for sound economic regulation in the field of energy, communications, aviation and competition is preserved.

In the light of these concerns, discussed above, and the fact that they cannot easily be put to rest, we believe that it is not safe to go ahead with the CER's I-SEM proposal. In the North of Ireland the commitment to a defective market regime in 1992 caused the consumers of the North to pay a massive price for electricity for around 15 years (McGurnaghan, 1995). Once the new defective market had been set up it could not be changed. Ireland should not embark on a potentially defective regime, which may be difficult or costly to change in the future. The option value of delaying and eventually getting an appropriate regime is very high.

An important objective of the development of a new I-SEM is that it should result in better use of the interconnectors. However, this aspect of the proposal also needs further research.

Any changes to the SEM need to guard against potential abuses of market power. The proposal to replace the current wholesale electricity pool, which is working fairly well, with a new day ahead market needs further testing.

The proposal to replace the current capacity payments system with a new approach looks very vulnerable to abuse through use of market power. On this basis, the existing SEM regime looks preferable to the CER's current alternative. However, this issue also merits further research.

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<sup>30</sup> It is interesting to look at the returns on bonds by firms, such as Rheinisch-Westfälisches Elektrizitätswerk AG (RWE), relative to firms operating under less arbitrary regimes.

Before moving from a market that works fairly well, it will be important to establish, with reasonable certainty, that any new market will not only remedy the problems encountered with the current market (e.g., interconnector flows), but will also maintain all the advantages of the SEM. It needs to be clearly demonstrated that the new market will produce lower costs for consumers in the long term. Consideration also needs to be given to the transactions costs involved in developing a new market structure.

#### 4.2.2 Replacement of Moneypoint

The issue of gas dependence and the security of gas supply has been discussed above. Here we consider another important issue, which will affect the availability of adequate generation capacity in Ireland in the long term. The Single Electricity System (SEM) on the island of Ireland is relatively small. Changes in a single generating plant can, therefore, have a relatively large effect on the system as a whole, especially if we refer to the replacement of the generating station on the system, namely the coal-fired Moneypoint plant. Whereas the decision of what new plant to commission falls with investors in the deregulated SEM, the examination of the effects of alternative generation options may provide insights into their impact on the wider electricity system.

Diffney *et al.* (2012) consider various replacement options for Moneypoint: a base-load natural gas combined cycle plant (CCGT), two types of coal plant, with or without carbon capture and storage (CCS), and a nuclear plant. They find that the optimal choice in terms of lowest electricity system costs depends on a number of variables, including the prices of carbon dioxide permits and fuels, the level of interconnection with Great Britain and the regulatory environment. As highlighted by Walsh *et al.* (2014), the appeal of a coal plant with CCS depends strongly on the expected price for carbon dioxide permits.

The authors argue that the nuclear plant option is unlikely to be implemented. Nuclear plants are large relative to both SEM peak demand and the size of currently installed generation plants. This implies that additional backup power would be needed to cover unexpected outages of a nuclear plant, making nuclear generation unlikely to be economic in the foreseeable future (see also FitzGerald, 2004b). Moreover, nuclear power is specifically prohibited in section 18(6) of the Electricity Regulation Act 1999 (Irish Statute Book, 1999) and there appears to be strong latent opposition to nuclear plants in the Irish population.

In addition to the direct effect of a new plant on the cost of the system, it is worth looking at issues of security of supply. As mentioned earlier, natural gas

fuels more than half of total electricity generation used to supply demand in Ireland. The combination of high dependence on imports and low gas storage means that heavy reliance on natural gas might affect security of supply. As a result, the least desirable option would be the installation of additional natural-gas CCGT plants. If this option were pursued, it would be necessary to investigate the consequences of developing ways of mitigating the implications of this for system security.

A final option is to delay the decision on shutting and replacing Moneypoint. The uncertainty around the construction cost of coal plants with CCS, and also about future price of natural gas and carbon dioxide permits, is likely to decline over time. Also, over time, interconnection between the Irish electricity system and that of the rest of Europe is likely to increase. This makes delaying the Moneypoint replacement decision a potentially appealing option. The downside of delaying making a decision can be measured by the extra running costs of the old, relatively inefficient, plant compared to the cost of running a new plant. Diffney *et al.* (2012) calculate the present value of five years of added costs (assuming a 2 per cent discount rate) to be between €539 million and €1,351 million in 2008 currency, when compared to the option of installing a new CCGT.

The best strategy may be to delay making a decision on a replacement for Moneypoint until the position about new low carbon or zero carbon technologies is clearer. This may require some additional work to extend Moneypoint's potential life to 2030.

#### 4.2.3 Transmission infrastructure

Several studies recognise the importance of the construction of a second North-South transmission line between NI and ROI, including CER (2012), FitzGerald (2004b) and Curtis *et al.* (2013). The new reinforced tie line is expected to be operative from 2017.<sup>31</sup> This would allow the SEM generation system to dispatch efficiently. Even more important, with the closure of plant in Northern Ireland in 2016, system security in the North will be seriously compromised without the additional interconnector. If the costs of electricity interruption in the North are similar to those in the rest of Ireland this would represent a serious risk for the Northern Ireland economy, highlighting the importance of completing the transmission line in a timely manner.

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<sup>31</sup> See SONI and Eirgrid (2011).

Curtis *et al.* (2013) study the impact of the North-South line (NS from now on) on the Irish market by simulating the system costs for the year 2016. They compare the cost of the electricity system with and without a NS tie line and find that building the NS line would reduce total system costs by 1.5 per cent and the emissions produced by the Irish electricity system by 2.6 per cent.

Removing transmission constraints between the North and the South of Ireland would enable power plants located in ROI to dispatch more efficiently. In the absence of the N-S tie line, Northern Irish generation plants, which are generally older and less efficient than ROI plants, are dispatched independently of their position in the merit order to ensure that system demand within the NI network is met. When the transmission constraints are relaxed more efficient power plants in the ROI will be able to generate electricity for the whole SEM system. With more efficient ROI plants displacing NI plants in the merit order, the SEM's system marginal price, determined by the marginal dispatching plant, will be lower. Their analysis suggests that increasing the capacity of the N-S tie line sufficiently for it to become unconstrained would reduce the SEM's yearly running costs by €30 million (for 2016) and it would lead to 0.9 per cent reduction in wholesale electricity prices. These costs are likely to grow over time as no new generation is planned for Northern Ireland. These costs are shared by all consumers on the island and, as a result, the higher costs arising from delay in delivering the tie line will impose a burden on Irish competitiveness.

Further transmission investment is also needed elsewhere in the system, in part to accommodate the increasing penetration of renewables (EirGrid, 2010). As plants change over time, the optimal grid infrastructure also changes. Incentivising the correct type of plant at the most efficient location is, therefore, important to maintain an efficient electricity system.

It is very important for all electricity users on the island that the strengthening of the North-South transmission infrastructure is completed quickly. Its absence is imposing significant costs on consumers across the island and these costs are likely to rise over time. In addition, after 2016, the absence of enhanced interconnection will put at risk the security of electricity supply in Northern Ireland.

#### **4.3 EFFECT OF WIND ON WHOLESALE ELECTRICITY MARKETS**

The biggest change that has occurred within the SEM since its inception in 2007 has been the increase in renewable generation (from 10 per cent in 2007 to 19

per cent by 2012; see SEAI, 2012b and 2013b). While the transmission system already needed strengthening, especially between Ireland and Northern Ireland, there is now an urgent need to improve transmission and distribution infrastructure to accommodate increases in renewable electricity.

Analysis of electricity systems around the world suggests that the returns to thermal plants will decrease with large amounts of wind (see Traber and Kemfert, 2011 for Germany). Garcia *et al.* (2012) use a stylised theoretical model to show that designing renewable energy incentives without affecting investment in conventional generation is challenging.

As the share of intermittent renewables – and especially wind – increases, thermal plant flexibility is at a premium. Di Cosmo and Malaguzzi Valeri (2014) find that current market rules might favour less flexible plants, creating more difficulties in balancing the market in the future. They show that, in the presence of increasing wind, the profits of base-load plants decrease for two reasons. First of all, more wind decreases the shadow price and, therefore, generally decreases the profits of base-load plants when they generate. Second, generators start up more often to follow the variable wind load. Moreover, technical constraints, both at plant and at system level, tend to favour less flexible plants. The need to comply with the constraints reduces the number of times less flexible plants turn on or off with respect to more flexible plants. Di Cosmo and Malaguzzi Valeri (2014) report that in a simulation with 3,000MW of installed wind capacity, a natural gas CCGT plant would lose about 3.5 per cent in profits with respect to a scenario with 1,889MW of wind whereas a less flexible coal plant would lose only 2.2 per cent.

#### **4.3.1 Renewable Energy Feed-in Tariff (REFIT) Design**

Renewables in Ireland are supported through the Renewable Energy Feed-In Tariff (REFIT). The cost of the REFIT scheme is collected through an additional charge levied on all electricity customers, the Public Service Obligation (PSO). The Irish scheme is based on a minimum price guaranteed to renewable generators for a period of 15 years. This scheme eliminates all the risk of low prices for investors, while allowing them to receive any upside that arises when the market price is higher than the guaranteed price. Farrell *et al.*, (2013) show that such a scheme can be efficient, i.e. designed to achieve the desired investment in renewables at the lowest possible cost to consumers, if the guaranteed price is set optimally. However, as the share of renewables in electricity generation increases, it may be more efficient to move to a scheme where generators and consumers share the market price risk (see Box B).

With increasing deployment of wind it may be appropriate to modify the REFIT scheme so that price risk is efficiently divided between investors and consumers. The current regime puts consumers at risk of paying for high subsidies if electricity prices are low and does not allow them to receive any market upside if electricity prices are high. Any future REFIT structure should be modified to take these factors into account. In addition, it is important to provide a mechanism to ensure that the deployment of wind generation does not exceed the ability of the Irish system to absorb the electricity generated.

The absorptive capacity of the Irish system depends on the level of interconnection to the outside world. Diffney *et al.*, 2009 suggest that if Ireland is to reach its target for deployment of wind by 2020 it will need to double the current level of interconnection with the outside world. If this does not happen the additional deployment of wind will significantly raise costs for Irish consumers, while providing only a small and decreasing benefit in terms of carbon reduction.

One possible market mechanism to produce an efficient deployment of wind in Ireland would be to constrain off wind when it begins to impose rising costs on the system and to constrain the wind generators in the reverse order to their initial connection to the system; recent arrivals would be constrained off first.<sup>32</sup> If, instead, the costs of constraining off were socialised across all wind generators then too much wind would be deployed, imposing unnecessary costs on the wind generators that deployed first on the system, as well as on consumers.

#### Box B: Defining An Efficient REFIT Scheme

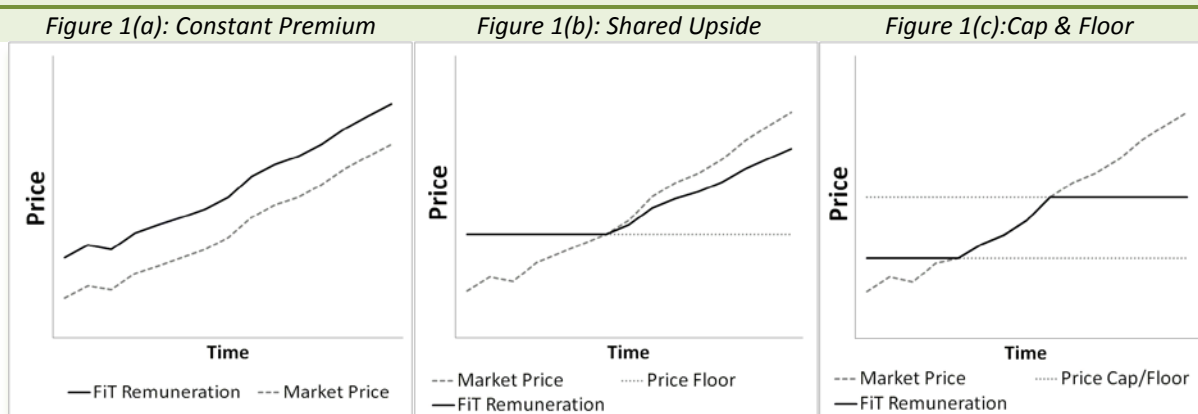
*Niall Farrell*

Farrell *et al.* (2013) outline several ways to structure a REFIT scheme. First, a generator may receive a constant premium in addition to the prevailing wholesale market price (Figure 1(a)). In this case there is no uncertainty for consumers, who face the same cost regardless of the market price, whereas generators are still exposed to market price volatility. Second, a market-independent fixed price may be offered during all trading periods. Under such a regime the consumer pays the difference between the market price and the fixed price when the market price is lower but receives an 'upside' any time the market price is greater than the REFIT price. In this case, generators are completely insulated from

<sup>32</sup> While this may prove difficult to achieve given current EU regulations, it is important that these regulations are, if necessary, changed to allow an economically efficient solution to the problem of deploying renewable technologies.

market volatility, as they always obtain the fixed price. Third, the generator may receive a price floor but also at least part of the upside when the market price exceeds the floor. The generator may receive all of the upside or it may be shared between the consumer and the generator according to a pre-defined ratio (Figure 1(b)). Generators and consumers share the exposure to market volatility. Finally, the market upside may be shared through a cap and floor structure, whereby upper and lower bounds ('cap' and 'floor', respectively) are placed on the price received by generators. The consumer must pay any shortfall below the floor and receives any 'upside' revenue in excess of the cap. This limits the uncertainty faced by generators (Figure 1(c)).

**FIGURE 1** Potential Renewable Energy Feed-in Tariff Design Options



Source: Farrell *et al.* (2013).

An efficient REFIT price is one that provides the minimum incentive necessary for generators to invest in new plants. A scheme with a price floor will be efficient if the floor is set low enough to provide the minimum incentive necessary to obtain the desired investment in renewables. If the price floor alone were sufficient to obtain the desired investment and the generator were permitted to share in the market upside, the scheme could be modified. The policymaker could collect the value of the upside and use any revenue from this source to lower any subsidy cost, effectively providing a 'hedge' for consumers against the risks of high fuel prices.

To help design an efficient scheme, Farrell *et al.* (2013) developed a model that takes the value of any "upside" into account when setting the price floor. For each potential REFIT design, they solve for an optimal balance between a guaranteed price floor and a share of the uncertain market "upside" for the generator. An incremental increase in the price floor is balanced with an incremental reduction in the share of market upside received by the generator. A spectrum of potential efficient REFIT schemes results, offering generators remuneration combinations ranging from zero upside/high floor price to all upside/low floor price. Similarly, this framework estimates the balance between a price floor and a price cap, where a higher price floor results in a lower price cap.

While all the options identified by the tool offer the same average return to investors, the level of risk incurred by investors and consumers varies. Information on the degree of risk aversion of investors and consumers offers more insights into how suitable each scheme is. Farrell *et al.* (2013), Devine, Farrell and Lee (2014) outline the risks that investors and policymakers face.

A fixed price tariff is suitable if investors are considerably more risk averse than consumers, a scenario that may arise if investors are extremely cautious; this is likely at times when renewables are initially being deployed. With a low level of renewables, REFIT subsidies will be a small proportion of consumers'

electricity expenditure, potentially making consumers less concerned about fluctuations in subsidy costs. A certain revenue stream will also make the final deployment level of renewables easier to predict. This policy may thus be most attractive when the achievement of specific renewable investment targets is of paramount importance.

A constant premium tariff is appropriate if consumers are highly averse to risk and investors are less concerned about certainty of remuneration (low risk aversion). However, in this case the quantity of renewables deployed is going to depend strongly on the actual (uncertain) market prices. This structure may be suitable when renewables penetration is relatively high, renewable subsidies represent a large proportion of consumers' electricity expenditure and the risk of not achieving specific targets is of a lesser concern.

A shared upside or cap and floor policy apportions market price risk to both consumers and generators, a positive feature if both categories are averse to bearing the full uncertainty of market prices. If market prices are lower than expected, a cap and floor policy protects investors from under-remuneration, thereby helping to achieve deployment targets. If market prices are considerably higher than expected, a cap and floor policy protects consumers from offering overcompensation, limiting policy costs. This cap may be offputting for less risk-averse investors, however, who may not want a cap on profit. In such circumstances, a shared upside policy may provide a greater incentive, perhaps resulting in deployment beyond the stated target. This may be desirable if policy targets are a lower bound and market prices have considerable potential to grow at a much greater rate than initially expected. Furthermore, if any positive deviations in the rate of price growth are modest, a shared upside policy allows consumers to benefit from the hedging effect of renewable energy to a greater extent than a cap and floor policy.

If investors and consumers have a similar degree of aversion to risk, investor preferences take precedence over consumer preferences, with a greater degree of market price risk borne by the consumer than the investor. However, should consumers' risk aversion increase relative to investors', the split of market upside going to consumers should also increase. Consumer preferences are of increasing importance as REFIT subsidies grow as a proportion of total electricity expenditure. This suggests that, as renewables deployment increases, designs that share market price risk may be of greater relevance.

### 4.3.2 Export-Only Wind

Creating a single electricity market in Europe will make it possible for renewable generation to be located in areas where it is more abundant in Europe and transferred to other areas across transmission lines. For this model to make economic sense, there must be a large difference in the ease of renewable energy harvesting between the two areas, since electricity transmitted along long distances is subject to significant losses. Farrell (2014) discusses how a large wind farm installed in Ireland specifically for export might impact the national and local economy. The first step is to disaggregate all the components of a wind farm project. IEA Wind (2011) and Denny, FitzGerald and O'Mahony (2014) provide an estimate of the relative importance of each component, as reported in Table 1. However, as well as the direct effect of the investment on the local economy there are a wide range of other costs and benefits which must be taken into account before deciding on the best approach to this opportunity.



IEA Wind (2011) has broken down the process of renewables deployment in Ireland by constituent economic activity. These are outlined in Table 1. Farrell (2014) argues that the manufacturing of turbines is unlikely to take place in Ireland, providing limited scope for the new wind farms to affect the manufacturing sector directly. In Denny *et al.* (2014) a similar conclusion is reached, with few jobs expected to occur in manufacturing, even with very high deployment of wind generation. While workers are likely to be employed locally during the construction phase, the effect on employment is likely to be limited once the wind farm is built. Two employees can service between 20 and 30 wind turbines (Hau, 2012). Denny *et al.* (2014) provide estimates of how many jobs might be generated over a 10 year period through different levels of deployment of wind generation. Box C gives a more detailed analysis.

**TABLE 1** Approximate Capital Cost (CapEx) Breakdown

Component	% of Total Cost
	%
Turbines	65
Project Development	4
Legal/Financing	3
Civil Engineering	8
Onsite Electrical	8
Grid Connection	12

Source: IEA Wind (2011).

### Box C: The Likely Direct Effect of a Large Wind Farm Installation on the Irish Economy

Turbines are generally imported as part of a turnkey installation contract with an international supplier. As Deloitte and IWEA (2009) note, international turbine companies provide installation by their own internal teams and turbine installation is thus likely to be imported also.

Manufacturing of turbine components in Ireland is unlikely, as Ireland would not have a first mover advantage. IWEA (2012) argues that, even with high levels of deployment of wind farms over a number of years, it is unlikely that the manufacturing of relatively small components will take place in Ireland as they are easy to import at limited cost. Some potential may exist for larger, heavier components that are difficult to transport, such as towers, blades and brakes. The extent to which this may occur in reality is in considerable doubt and IWEA (2012) state that interaction between industry and government agencies is important to facilitate such development. Denny *et al.* (2014) suggest that, even with very high deployment of wind generation, the number of jobs likely to occur in manufacturing in Ireland is likely to be relatively small.

Turbines for a possible UK export project would be larger than those deployed to date, so there may be potential for the use of concrete-based towers to support the turbines, which are particularly suited to larger turbine designs (Tricklebank *et al.*, 2013). Ireland has expertise in the manufacturing of concrete-based products and this sector could potentially expand by increasing output of current plants or investing in a new plant. Such a bespoke plant might be located close to the export projects in the midlands. Hau (2012) suggests that a tower may comprise roughly 20 per cent of total ex-works turbine

costs. Assuming turbine costs account for 65 per cent of total CapEx, as shown in Table 1 in the main text, a wind tower makes up about 13 per cent of total CapEx. Although this may be greater for larger turbines and is subject to change depending on materials employed, this value gives an approximate benchmark as to the potential impact should such manufacturing activity be carried out locally.

The wind industry in Ireland is dominated by project developers (EWEA, 2011). Project developers coordinate the installation project, prospect for suitable sites, carry out resource assessments and negotiate contractual agreements with property owners. Developers commission further work which may be located locally, including environmental impact assessments and financial advice, lender/financier involvement and legal advice. Ireland has considerable capability to serve these requirements.

Civil construction work includes foundation installation, construction of access roads and ground preparation (Hau, 2012). As Deloitte and IWEA (2009) and O'Neill *et al.* (2012) outline, there is considerable civil engineering capacity in Ireland and, given the requirement to carry out such activities on-site, there is potential for this activity to benefit the local economy. With respect to on-site electrical work, an electrical 'balance of plant' contract may incorporate the design and construction of an on-site power substation, inter-wind farm array cabling and fibre-optic cabling to all turbines (Premier Construction, 2012). Payment for grid connections is received by the relevant system operator (ESB Networks) for distribution network-connected generation. This may also be the case for transmission connections (typically generation schemes with an export capacity greater than 20 MW), but the developer has the option to take responsibility for the construction of the connection assets in such installations (SEI, 2008). This may involve the hiring of an engineering firm. Ireland is likely to be able to meet demands for civil engineering, electrical engineering, labouring, health and safety, turbine transport and crane activities (Deloitte and IWEA, 2009 and O'Neill *et al.*, 2012).

Denny *et al.* (2014) estimate the number of 10-year full time equivalent jobs for three different scenarios on the deployment of wind generation. In the case of the first scenario it is assumed that 4GW of wind generation is built onshore – the base case. In the second scenario it is assumed that a further 4 GW of generation, mostly on land, is built exclusively to supply an export market. The grid jobs involved take account of the fact that this option would involve major investment in interconnectors. The third scenario also involves exporting all the additional electricity with most of the additional generation being located offshore. These estimates are shown in Table C1.

**TABLE C1:** Estimated Number of 10-Year Jobs for Different Scenarios on Wind Generation

	Scenario 1	Scenario 2	Scenario 3
Development & Operation of Generation	5,600	11,200	16,600
Grid	1,100	2,400	3,900

Although the labour for these construction activities is likely to be sourced in Ireland, some of the materials may be imported. This is of particular relevance for onsite electrical and grid connection operations as cabling represents a large component of total cost.

#### *Total Economic Impact*

Denny, *et al.* (2014) suggest that the bulk of the jobs would be created in the wind industry itself. There would also be significant numbers of jobs as a result of the investment in the grid and interconnection. The number of jobs in manufacturing would be limited. Finally, the *HERMES* macro-economic model of the economy was used to estimate the number of jobs that would be created elsewhere in the economy as a result of the enhanced level of economic activity. These induced jobs would also be quite significant,

especially in the case of Scenario 3. However, given recent developments in negotiations with the UK, Scenarios 2 and 3 look much less likely to happen than Scenario 1, which is on course for completion by 2020.

In estimating the induced jobs it was assumed that the government holds the borrowing requirement unchanged, using any additional revenue from the expansion of the wind industry to cut taxes. On this basis it was estimated that the programme of investment in wind would add between 0.4 per cent to the level of GDP in 2020 under Scenario 1, up to 1.4 per cent under Scenario 3. Total employment in the economy in 2020 would be raised by between 0.4 per cent and 1.8 per cent under the different scenarios.

Because of the magnitude of the investment under Scenarios 2 and 3, there would be a significant impact on the macro-economy. In scenarios 2 and 3 the increase in investment in wind could amount to between 0.7 and 1.5 per cent of GDP in 2020. Thus, this investment programme could have real macroeconomic significance.

The total jobs created directly and indirectly under Scenario 2 could amount to around 17,000; under Scenario 3 the figure would be around 36,000. These figures include the number of induced jobs and are calculated on the assumption that the improvement in the public finances is used to reduce the burden of taxation.

### 4.3.3 External Impacts of Wind Deployment – Focus on Export-Only Wind

The construction of a large wind project involves several externalities, many of which have not been measured in the specific Irish context.

Bergmann and Hanley (2012) and Moran and Sherrington (2007) give a comprehensive review of the external environmental benefits and costs associated with wind energy deployment. Wind energy deployment may bring with it some additional benefits alongside CO<sub>2</sub> mitigation: reduced emission of particulates may decrease the incidence of certain chest and heart problems whilst reduced SO<sub>x</sub> and NO<sub>x</sub> emissions may reduce any negative impact on water quality, historic buildings and crops (Bergmann and Hanley, 2012). Wind turbine deployment may also have negative environmental impacts. These include disamenities associated with the visual impact and sound of the turbines themselves and any potential network infrastructure, along with potential disturbance of animal and bird habitats. Bergmann and Hanley (2012) discuss techniques of non-market valuation that may be employed to value these effects in order to incorporate their impact in a comprehensive assessment. Although not quantified to date, these impacts should be considered in a comprehensive net economic assessment.

A number of external impacts particular to the proposed export projects may also be noted. First, locating a portion of UK wind generation in Ireland may result in greater coupling of the British Electricity Trading Transmission Arrangements

market (BETTA) and SEM wind output, affecting the export potential of SEM-connected wind generation. However, the presence of additional interconnection may aid SEM-connected generation, should provisions be made for such capacity to avail of this infrastructure. Although not quantified to date, these impacts should be incorporated in a comprehensive net economic assessment.

One suggested location for these projects is on spent peat land (Bord na Móna, 2014). Although undisturbed peat land acts as a carbon sink and contributes towards biodiversity, peat harvesting activity has disturbed much of these environmental services (Strack, 2008; Collier and Scott, 2008). Post-harvesting, the biodiversity of these sites may be regenerated (Chapman *et al.*, 2003; Kimmel and Mander, 2010), or they may be set aside to provide after-use biodiversity services (Collier and Scott, 2008). Such uses are not possible if these sites are used for wind farm development. A comprehensive economic analysis should incorporate the value of these potential uses relative to alternative uses for non-peat land-based deployment sites. Irish evidence to value the environmental impact of either outcome does not exist. However, Bullock *et al.* (2012) discuss the ecosystem, public good and market services offered by peat land. Bullock and Collier (2011) estimate the cultural value of intact regenerated peat land, a (non-market) factor that should also be accounted for in a comprehensive economic analysis.

Provided that export of electricity generated by wind takes place directly, without passing through the Irish electricity grid, and provided that there is no subsidy paid by Irish taxpayers or consumers (either directly or indirectly, including through the tax system), then it should not adversely affect the Irish economy or consumers. However, if any of it were to pass through the Irish transmission or distribution system it could impose serious costs on the Irish economy by increasing congestion or necessitating further investment in the grid. It will be important to develop rules which ensure that any such costs are recouped, so that Irish taxpayers and consumers are not adversely affected. It will also be important that EU rules support this approach, i.e., allowing the Irish authorities to ensure that all output of electricity, including exports from offshore wind generators, pays the full costs that they impose on society.

In addition, an agreement to supply renewable electricity to the UK to help them meet their EU obligations could have longer term implications for Ireland. If Ireland had to strive to meet renewables obligations in the future then forgoing some of the renewables generated on the island to meet the UK obligation could necessitate more expensive alternative investment in Ireland. Hence there is an option value to forgoing such wind generation and this would need to be reflected in any long-term agreement with the UK.

The recent proposals for large-scale wind generation in Ireland for export were designed to ensure that there were no net costs for Irish consumers. In assessing their future value for the Irish economy a range of other factors needs to be taken into account.

#### 4.4 REGULATORY CERTAINTY AND THE COST OF CAPITAL

A key feature of the electricity and gas sector is its capital intensity. This has a number of important implications.

Because the capital stock is typically long-lasting, the remuneration of investment might also be expected to be funded over a similarly long-time horizon. If the investors are able to charge long-run marginal cost then they will see their investment repaid out of the future profits from operating the capital stock. However, uncertainty about future markets, future technical change, and the behaviour of regulators may mean that prices could fall below long-run marginal cost at some future date, before the investment is paid off, resulting in a loss for investors. This uncertainty must affect both the cost of financing the investment and the approach that the investor will take to recovering the initial outlay on the capital stock. The more uncertain the future return on the investment, the higher the cost of capital for the investor and the higher the return that the investor must expect to recover from future revenue. Higher risk will also be associated with a need to recover the cost of the investment over a much shorter period than the expected operating life time of the asset.

The uncertainty arising from the development of future markets arises because the investor cannot be certain that the price for the commodity that it is producing will be adequate over the asset's life time to repay the initial investment. For example, in the case of electricity generation, the future movement of fuel prices or carbon prices could result in the price for electricity set on the market falling below the long-run marginal cost of production from the operator's plant (or being higher than expected). The price could even fall below the short-run marginal cost of production for a particular plant, effectively stranding the asset.

Technical change may also cause future returns from an asset to be less (or more) than expected. For example, changes in the source of natural gas available for European markets could see extensive parts of the EU gas transmission network becoming redundant at some date in the future before the network is fully

depreciated. While such changes may be unlikely in the immediate future, given the long lives of the assets, such changes cannot be ruled out before the assets reach the end of their natural lives. Depending on the type of asset, the exposure to unexpected technical changes will vary. In the case of investment in electricity generation, technical change could well render a plant redundant before the end of its useful life. In the case of electricity transmission, while it is unlikely that the bulk of the transmission system could be rendered redundant by technical change in the future, it still remains a possibility<sup>33</sup>.

Finally, the electricity and gas markets are heavily regulated across the EU. Unexpected changes in the behaviour of regulators, that do not have clear economic justification, could have major implications for the future return on valuable assets. A good example of this is the decision by the German government to require all nuclear plant in Germany to close well before the end of its engineering life span. This imposes a major cost on the owners of these assets and it will also require major new investment in alternative sources of electricity generation before it would otherwise have been necessary. The possible exercise of arbitrary behaviour by regulators elsewhere in the EU is a significant source of risk to investors in energy infrastructure everywhere. In turn, this must raise the cost of capital for new investment in Germany and elsewhere in the EU. To the extent that regulatory authorities can enhance their credibility and reassure market players about their regulatory behaviour in the future, some of this risk can be reduced (Lyons *et al.*, 2007).

The stable regulatory regime in Ireland over the last decade has contributed to good decision making by private investors and to minimising the cost of capital needed to fund those investments. In developing the electricity and gas markets over the coming decade it will be important to maintain this approach, providing a stable environment for the large-scale continuing investment needed in the sector.

#### 4.5 ENERGY POLICY AND EMPLOYMENT

A frequently argued case is that investment in energy efficiency or in renewable energy creates jobs. This issue also receives some attention in the recent government Green Paper on Energy (Department of Communications, Energy and

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<sup>33</sup> For example, transmission put in place to allow deployment of wind generation could be rendered redundant if technical change resulted in new more efficient forms of renewable electricity becoming available.

Natural Resources, 2014). However, if the investment in green energy or in energy efficiency has to be part funded by the state, either directly or indirectly, then the cost of the taxes or regulations needed to finance it will be a significant destruction of jobs elsewhere. Honohan and Irvine (1987) showed that in the 1980s, at the then very high marginal tax rates, there had to be a huge return from state expenditure (including in terms of jobs) if it was to offset the jobs lost from the taxation needed to fund the expenditure. This cost was particularly high in the 1980s because of the high marginal tax rates. They estimated that the cost of a euro raised in taxation through this income tax could be over 2 euros because of the damaging effects of the taxation.

Over the 1990s with falling tax rates the opportunity cost of state funds fell (Honohan, 1998). In addition, with a return to full employment the shadow price of a job rose to around 0.8 (each job created would see a reduction in jobs elsewhere of roughly 0.8 of a job). While marginal tax rates today are lower than they were in the mid-1980s, they are still much higher than they were in the 1990s or the last decade. Thus, the cost of using public funds to fund investment, including investment in job-intensive energy projects, is again likely to be very high.

While we currently face high unemployment, this will not last indefinitely and, when considering investment, the labour market conditions to consider are the conditions, not of today, but of the future when the investment takes place.

The appropriate methodology for assessing the value of investment projects was first developed in Honohan (1997) for Forfás and further developed in Barry, Murphy and Walsh (2002). This is the approach which should be used in assessing the value for the nation of investment projects involving taxpayers' money, including investments in energy efficiency.

Energy policy should concentrate on delivering a secure energy supply to consumers at minimum cost. If the necessary investment to produce the energy at minimum cost results in new jobs that is a bonus. However, the jobs content of the investment should not be an objective of energy policy.





# Chapter 5

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## Demand Side

Policy interventions in the energy area are justified from an economic perspective when markets are not working perfectly on their own. This is often the case when there is a difference between the effects of economic decisions on the individuals who make such decisions versus society as a whole. We refer to such differences as externalities. When there are externalities that are not reflected in prices, resources tend to be allocated inefficiently. In addition to issues of efficiency, changes in policy may be needed for equity reasons or regulatory changes at the EU level. In this section we consider how policy can contribute to the goal of reliably providing energy at minimum cost, while protecting the environment and accounting for distributional issues.

Energy prices that are excessively high impact on consumers, whether they are households or companies. High prices reduce households' spending power and, given the nature of energy consumption, the incidence is larger for low income households. In the case of companies, high prices significantly impact on their competitiveness, with knock on negative effects on employment and output.

One challenge for energy policymakers is that energy prices may not capture all the externalities involved in energy use and also there may be market imperfections which mean that households and companies may not react precisely as one would expect to price signals, however imperfect.

In the following sections we explore how energy prices and changes in energy policy can affect the residential, manufacturing and commercial sectors.

### 5.1 CONSUMER CHOICE IN ENERGY MARKETS

As mentioned in Section 4.2, the SEM will experience changes in its market structure to meet the EU Target model requirements. These changes will affect the demand side of the market as well as the supply side, as all of the options being considered include more demand-side participation. Moreover, patterns of electricity consumption are likely to change over time, for example, if electric vehicles or electric heating are widely adopted.

Anticipating the scale of demand-side participation is not straightforward as consumers do not always respond to price signals in a simple way. Jessoe and Rapson (2014) suggest that better informed consumers react more to price signals. Households that were assigned in-home displays increased their response to prices between 8 and 22 per cent, more than those who were only exposed to well-advertised price changes (0 to 7 per cent). In-home displays show consumption and electricity prices, providing real-time feedback and promoting consumer learning. This is consistent with the results found during the Irish electricity smart meter trial by Di Cosmo *et al.* (2014), who show that households with in-home displays react more to changes in prices. Di Cosmo *et al.* (2014) use the smart meter trial data to investigate other aspects of consumers' reactions to electricity prices. They: (i) estimate the effects of different time-of-use (TOU) tariffs (peak, day and night) and stimuli on residential electricity consumption; (ii) investigate the determinants of electricity consumption; (iii) check whether the socio-economic characteristics of households influence their responses to prices and information stimuli. The authors find that TOU tariffs decrease peak-time electricity consumption for all households. Households with in-home displays curtail consumption more when the ratio of peak to off-peak prices increases, whereas households that do not have in-home displays do not. This suggests that consumers responded on the basis of a simple heuristic: they knew prices were higher at peak times than at other times of the day and changed their behaviour to reflect this, but further increases in the differential were possibly not fully perceived.

There are no significant differences in the behaviour of households with low and high education levels (where the level of education is determined by the education of the head of household). For peak periods, the reaction of highly educated households to the peak pricing structure is similar to that of low educated households, although the effects are slightly smaller in magnitude for the former. Higher educated households who receive bills at longer intervals (every two months) respond to higher peak prices more, whereas low educated households respond more when they have in-house displays, both when prices increase at peak times and decrease during the night.

More information does not always mean more active consumers, as highlighted by Gorecki *et al.* (2010). Evidence across a range of markets suggests that, where decisions involve too many options or too much information on each option, consumers become less inclined to be active and more likely to make poor decisions (Wilson and Waddams Price, 2005, in the UK electricity market; Frank and Lamiraud, 2009, in the Swiss health insurance market). Faced with a more complex decision, consumers are likely to assume, correctly, that they are more

likely to make decision mistakes and will therefore be less inclined to proceed. Cognitive costs will also be reduced where consumers already have experience of dealing with similar issues in other similar markets. Chang and Waddams Price (2008) found that customers in the UK who had switched in other markets were more likely to switch electricity supplier.

Gorecki *et al.* (2010) suggest that the effectiveness of policy can depend on the degree to which policy results in good decisionmaking by consumers. There is a cost to consumers of acquiring information. This may limit their ability to choose the best available prices in an open market. Wilson and Waddams Price (2010) found that 20-32 per cent of British electricity consumers who switched to obtain better prices ended up actually paying more, while less than 20% switched to the firm offering the highest savings.

Most of the demand-side studies focus on the residential sector because of a lack of data on industrial and commercial consumption. Better data on these sectors is necessary to gain an improved understanding of the effect of energy policies on consumption as a whole. However, O'Malley, *et al.*, 2003 showed a diversity of experience among commercial energy users with some focusing on energy savings whereas other sectors were not exploiting the opportunity to cut energy costs.

## 5.2 ENERGY USE IN MANUFACTURING

Since the 1973 oil crisis many researchers have studied the relationship between capital and energy in the production process. Much of the early international research on this subject was motivated by the hypothesis that the 1973 oil crisis caused a reduction in capital investment resulting in a slowdown in productivity growth. This hypothesis was based on the assumption that energy and capital are complementary in the production process, meaning that rising energy prices will cause the demand for energy to fall, which will cause the demand for capital to decline also. If, however, capital and energy are substitutes in the production process, a rise in energy prices will cause an increase in energy-saving capital investments.

Haller and Hyland (2014) find that energy demand in manufacturing is highly sensitive to energy prices: an energy price increase of 1 per cent leads to a drop in energy demand of 1.5 per cent in the long run. Moreover, the evidence shows that other factors of production (namely the demand for capital, labour and material inputs) are substitutes for energy. When energy prices increase, demand

for capital, materials and labour increases. The estimated elasticities are however low, meaning that increases in the other factors of production will be limited. This means that charging the full effect of increases in the price of energy to the business sector will lead to a substitution of labour and capital for energy. However, there may also be some substitution of foreign output for domestic output if firms' competitiveness is seriously affected (Bergin, *et al.*, 2013).

Box D provides more detail on the impact of rising energy prices on the demand for capital inputs in Irish manufacturing.

Increases in energy prices can, in theory, affect the competitiveness of firms. Haller and Hyland (2014) show that this effect is likely to be small for Irish manufacturing firms for reasonable changes in energy prices. Energy costs account for only about 2 per cent of overall expenditures; in the long run Irish firms in the manufacturing sector are likely to react to higher energy prices by using slightly more labour and capital in their production process; foreign-owned firms are less likely to adjust their production processes, a result that is consistent with these firms being more energy-efficient in the first place.

#### Box D: Factor Input Substitution in Irish Manufacturing

*Marie Hyland*

Whether energy and capital are substitutes or complements has important implications for the response of firms, industries and ultimately countries to increases in energy prices or to policies that increase energy prices.

The relationship between these two factors of production can be determined by looking at what happens to the demand for one input when the price of the other input increases, as revealed by the cross-price elasticity of demand for the two products. A positive cross-price elasticity indicates that the two factors are substitutes while a negative cross-price elasticity indicates that they are complements.

As set out below the elasticities are long run rather than short run. It takes some time for firms to substitute one factor for another, for example through investment.

#### **RESULTS:**

#### **OF THE FOUR FACTORS ANALYSED, THE DEMAND FOR ENERGY IS MOST SENSITIVE TO CHANGES IN ITS OWN PRICE:**

Haller and Hyland (2014) use data from the Irish Census of Industrial Production to look first at how responsive the demand for each input is to changes in its own price. The authors find that, of the four factors, the demand for energy responds most to a change in its own price: a 1 per cent rise in the price of energy causes the demand for energy to contract by 1.5 per cent in the long run (see Table 2 below).

**TABLE 2** Own Price Elasticity of Demand – Average Across All Firms

Capital	Labour	Materials	Energy
-0.628	-0.477	-0.794	-1.465

Notes: These estimates represent the percentage change in the quantity demanded of each input when its own price increases by 1 per cent. All estimates are statistically significant.

**ALL OTHER INPUTS ARE SUBSTITUTABLE WITH ENERGY IN THE PRODUCTION PROCESS**

The results reveal that, across the average of all Irish manufacturing firms, all factors are substitutable with energy. However, the substitutability between energy and the other inputs is low. A 1 per cent increase in the price of energy causes the demand for capital to increase by 0.04 per cent, while the responsiveness of labour and material inputs is even smaller at 0.01 per cent and 0.02 per cent respectively (see Table 3). Haller and Hyland (2014) argue that the general unresponsiveness to changing energy prices may be due to the fact that the share of energy expenditure in total costs is small, at 2 per cent on average. Therefore any changes in the price of energy will represent only a small change in total costs and, hence, in competitiveness.

**TABLE 3** Cross-Price Elasticity of Demand w.r.t. Energy Price – All Firms

Capital	Labour	Materials
0.038	0.012	0.024

*Notes:* These estimates represent the percentage change in the quantity demanded of each of the other inputs when the price of energy increases by 1 per cent. All estimates are statistically significant.

The estimated cross-price elasticities are asymmetric: while the demand for other factors responds very little to changing energy prices, the demand for energy is quite responsive to changes in the price of other inputs. A 1 per cent increase in the price of capital, materials and labour causes the demand for energy to increase by 0.92 per cent, 0.41 per cent and 0.13 per cent respectively.

**THE DEGREE OF SUBSTITUTABILITY VARIES BY COUNTRY OF OWNERSHIP AND OVER TIME**

Haller and Hyland (2014) find that firms of different size and type do not respond to changes in energy prices in ways that are statistically significant. Significant differences emerge only when the firms are split by country of ownership and studied for different time periods.

**TABLE 4** Capital-Energy Cross Price Elasticities by Firm Size, Trade Status, Country of Ownership and Over Time

Ownership		Time	
Irish-owned	0.039	1991-2000	0.045
Foreign-owned	0.026	2001-2009	0.025

*Note:* These estimates represent the percentage change in the quantity demand of capital when the price of energy increases by 1 per cent. All estimates are statistically significant.

Table 4 shows large differences in the degree of substitutability when the firms are divided based on their country of ownership. Foreign-owned firms have been shown to be larger, more productive and more technology-intensive than domestic firms (for Ireland see, e.g., Barry *et al.*, 1999). They may be using more advanced production technologies. Compared to Irish-owned firms, foreign-owned firms respond less to changing energy prices: this is consistent with the fact that foreign-owned firms may already employ more energy-efficient production technologies.

Finally, the data in the sample are split into two time periods: from 1991 to 1999 and from 2000 to 2009, and the authors estimate the elasticities separately for the two periods. There is a large and significant drop in the responsiveness of the demand for capital to changing energy prices from the first to the second half of the sample. This result may be explained by the fact that the share of energy costs in total costs also fell over time.

**Box E: Emission Factors for Electricity under Building Compliance Regimes in Ireland and the UK***Marie Hyland*

Fuel compliance targets are used in planning regulation to improve the energy and carbon efficiency of buildings in line with national and EU policy objectives. Before construction, the lifetime fuel use of the building is estimated. It is required to be equal or lower than a defined target.

This research evaluates how the lifetime fuel consumption and carbon dioxide emissions are estimated in Ireland and the UK, focusing on buildings that plan on using electricity as the main heating source. The DEAP (Irish Domestic Buildings), NEAP (Irish Non-domestic Buildings) and SAP (UK Buildings) systems are examined. Both NEAP and DEAP frameworks calculate the emissions associated with a dwelling, but the focus of the building regulations legislation, the Energy Performance of Buildings Directive (EPBD), is on the minimisation of energy use of a dwelling.

Ireland, as with other EU countries, is subject to a stringent carbon reduction target. Electricity has a key role to play in meeting this target as it is a sector that has experienced – and is expected to continue experiencing – a large carbon reduction. It therefore matters if Irish building standards are biased against using electricity as a main source of heating.

A significant increase in the use of electric heating in the next few decades requires that a significant share of the new buildings be built with electric heating systems. Most buildings set their heating system and emissions profile for approximately 15-20 years at the time they are constructed and, thus, compliance targets must take note of both current and future performance. For most fuel sources, predicting future emissions is not difficult. Emission factors for electricity, however, typically vary year-on-year and have shown a consistent downward trend over the last number of decades. These changes in emissions from electricity create a particular problem in evaluating the environmental impact of electricity use over the lifetime of a building. As discussed below, the Irish and UK building standards address this issue in different ways.

***Overview of the Irish System***

Part L of Irish building regulations (Department of the Environment Community and Local Government, 2011) specifically refers to minimising energy use and carbon emissions of a building. A building derives an Energy Performance Coefficient (EPC) based on the ratio of its Primary Energy Consumption (PEC) to that of a hypothetical reference dwelling. In order to calculate the PEC and CO<sub>2</sub> emissions of the building, the projected energy use for heating and lighting are added up and multiplied by the Primary Energy Factor (PEF) and Carbon Emissions Factor (CEF) for each fuel.

The PEFs of most fuels currently range from 1.05 to 1.35, with mains gas, heating oil and house coal all providing a PEF of 1.1. The current PEF for electricity is significantly higher at 2.45, reflecting a grid efficiency of 41 per cent, due to the higher fuel inputs required to produce electricity. Furthermore, at 0.555 the current carbon emissions factor for electricity is significantly higher than that of other fuels: for example, the emission factor for coal is 0.361 and for gas is 0.203. Naturally, a higher PEF or CEF results in a higher estimate of a house's primary energy consumption or carbon emissions, making it harder to achieve the energy performance and carbon performance targets set out in the building regulations.

Within the Irish system, energy and emissions factors are based on historical electricity generation data, provided by the national Energy Balance. Under the current domestic system (DEAP 3.2), there has been automatic updating in place for a number of years, which reflects the yearly changes in carbon intensity of electricity generation. Yearly updating has meant that the PEF and CEF for electricity have fallen on an

annual basis. This gives an accurate profile of the primary energy and emissions of a dwelling at the time it is constructed. Crucially, however, it gives no indication of the future performance of the building, as it takes no account of possible future decarbonisation of electricity.

The Irish Non-Domestic buildings process, NEAP, provides an even larger bias against the use of electricity. The energy and carbon performances of the building are calculated in a similar manner to those of domestic buildings. The key difference is that the emission factors applied to electricity are not automatically updated. In fact the PEF and CEF used in the current version of NEAP, which are 2.7 and 0.643 respectively, represent the emissions profile of the electricity grid circa 2003/04.

The over-estimation of lifetime emissions for Irish, particularly non-domestic, buildings using electricity as the main heating source has a straightforward impact on their ability to meet compliance targets. Under the Irish system, homes which use higher-emission fuels, such as electricity, must be built to a higher fabric standard than gas-heated homes in order to meet the same compliance standards, thus increasing the construction costs. Furthermore, future decarbonisation of the grid, which would improve the future performance of buildings using electric heating, is not accounted for in the assessment procedures. While investment in energy-efficient or low-carbon technologies may be desirable within the building stock as a whole, this places an unfair (and inefficient) burden on potential users of electric heating.

In the long run, if the electricity system decarbonises faster than other energy uses, as a result of this policy Ireland could find itself with an environmentally and economically inefficient building stock. Because of the long life time of buildings this mistake could prove very costly to remedy and lead to substantially higher carbon emissions over the rest of the century than might otherwise be the case.

### ***Overview of the UK System***

The UK system differs from the Irish system in a number of ways; here we will focus on two particular attributes of the UK system that are not present in the Irish system: the use of forward-looking emission factors and the inclusion of a fuel factor for electricity. The SAP (domestic) and SBEM (non-domestic) building regulations use emission factors for electricity that are based on (expected) future electricity emissions, according to electricity generation projections. The current version of SAP (SAP2009) and SBEM are based on 5-year emission projections. However, this too has been problematic: in the past, projected levels of decarbonisation in electricity were not achieved, meaning that 5-year emission factors for buildings using electricity as heating were underestimated.

If 5-year emission factors are estimated inaccurately, this makes them unsuitable to be used to estimate buildings' total emissions. When emission factors for electricity are optimistically low, houses may be constructed to insufficiently strict standards. A revised version of SAP (SAP2012) is set to provide both 3-year and 15-year estimates, with the 3-year figure being key for compliance with legislation.

The difficulties in projecting future electricity emissions accurately argue against a direct transfer of that system into Ireland. However it is worth noting an additional feature of the UK regulation: the use of what is known as a "fuel factor". This factor raises the permissible compliance rate of emissions for houses that are not connected to the natural gas grid, a fuel with lower emissions than oil or coal. Under the Irish system, homes which use higher-emission fuels, such as electricity, must be built to a higher fabric standard than a gas-fuelled home in order to meet the same compliance standards, thus increasing their construction costs. New buildings that use electricity as heating must have more efficient features than any designed to use coal or oil as the main fuel. The fuel factor is an attempt to find a balance between reducing emissions from buildings and minimising increases in construction costs.

The conclusion of our analysis is that energy and emission factors based on historical electricity generation profiles overestimate the lifetime emissions of buildings and their heating systems. This imposes capital costs in the form of unduly high-efficiency or low-carbon measures for buildings where electricity is being used for heating. Specifically in relation to Irish non-domestic building, we would recommend that factors used in this area should be updated in line with those utilised in DEAP, and indeed the Department of Environment, Community and Local Government are in the process of considering revisions to Part L of NEAP (relating to the conservation of fuel and energy), which is due to be released in 2015. While forward projections do not appear to give the reliability required under compliance regimes, in that overly optimistic projections could lead to substandard construction, there may be benefits in following the UK procedure, in providing a projection to inform the likely emissions profile of a building over a longer time horizon. Furthermore, the inclusion of a fuel factor should be considered to alleviate the burden placed on houses not connected to the gas grid.

### 5.3 BUILDING STANDARDS

Regulations on a building's maximum allowable fuel consumption are used to comply with national and EU policies. Improving the efficiency of buildings leads to lower energy consumption expenditures on heating and lighting. The lifetime expected fuel use of a building is estimated before construction. The methodology used to estimate fuel use and carbon dioxide emissions is therefore important since it determines if a building will be approved or not.

In Ireland this evaluation may be especially important for buildings that plan to use electric heating. Ireland, as with most EU countries, is subject to a stringent carbon reduction target. Electricity has a key role to play in meeting this target as it is the sector with the highest penetration of renewables.

Ashe and Hyland (2012) focus on how buildings with electric heating are evaluated in Ireland and the United Kingdom. They find that, at the moment, buildings which use electricity as the main heating fuel are at a disadvantage in Ireland since the expected emissions of electricity are estimated on the basis of historical emissions. Historical emissions are likely to be higher than future emissions since the penetration of renewables in electricity is expected to continue increasing. For more details see Box E.

In order to facilitate the efficient reduction of greenhouse gas emissions from buildings, policy should change the emissions assumptions used in the calculations to use up-to-date parameters. It is also worth considering taking some account of likely future emissions reduction in electricity generation, but the mechanism used should balance the risks of overestimation and underestimation of future changes to emission factors.



#### 5.4 ENERGY EFFICIENCY

There is extensive evidence that the energy services enjoyed by the population could be obtained with a significantly reduced energy input through increased energy efficiency. However, while there are many opportunities for investing in energy efficiency, they are often not availed of by households and companies. In many cases the reason is that a particular investment in energy efficiency may not be cost effective. However, there are undoubtedly cases where market failure results in underinvestment in energy efficiency, in spite of the fact that investment would be cost effective: for example, consumers may fail to invest because they are unaware of the possibility of saving money or because they do not have access to sufficient credit.

The objective of public policy should be to first address any market failures that exist, facilitating the implementation of energy and cost savings by households and companies. In some case this intervention can take the form of regulation, where the change in rules specifically addresses a market failure. An example of such an intervention is the Building Energy Rating (BER) scheme, discussed later. Direct intervention by the state using subsidies must be justified with reference to an appropriate cost benefit analysis. Because of the high cost of public funds, the return for the state on any expenditure on subsidies must be quite high to warrant such an intervention.

One approach that has recently been adopted in some countries (notably the UK) is to impose residential efficiency obligations on energy suppliers. It is now being introduced in Ireland. On the face of it, this might seem an appealing option because there is no direct cost to the exchequer. However, it still imposes real costs on the economy. If the obligations are sufficiently stringent to have a meaningful effect, energy suppliers will incur costs to achieve the energy savings objectives that they have been set. Because the obligation is imposed on all suppliers, under competitive market conditions they will recoup the cost through higher charges for all consumers. The first major problem with cross-subsidising efficiency measures in this way is that the additional charge to consumers will, like all taxes, have a higher economic cost than the revenue actually raised (Honohan and Irvine, 1987). The way the charges are levied (by increased charges by suppliers) may involve higher welfare losses than if the revenue were raised by other tax measures. Direct subsidies from the exchequer involve extra costs due to tax distortions as well, but they are more transparent, and specific interventions can be prioritised to favour those with the highest net societal benefits. Suppliers have no reason to take deadweight losses due to cross-subsidisation into account when choosing measures or recovering the costs; they will naturally wish to maximise profits instead.

The second major problem with delivering energy efficiency measures through supplier obligations is that there is no reason to think that the schemes they will undertake will be the most cost effective or socially desirable. There are many actions they could take, from direct investment to spending on education or subsidising loans. Suppliers have an incentive to choose measures that meet the targets at least net cost to themselves. There is no reason to think these will be the most effective or efficient measures from a social perspective. If the quality or effectiveness of measures can only be imperfectly monitored by government and higher quality measures cost more, suppliers will have an incentive to choose measures that are of lower quality, even if the higher quality measures would have had a greater payoff to society. Additionality is a concern here too; even with direct subsidies it is sometimes difficult to avoid measures that would have been taken by households anyway in the absence of intervention, but there is no obvious incentive for suppliers to avoid such actions and less scope for effective monitoring or evaluation.

A third major problem with measures of this kind is that they take social welfare policy decisions out of the hands of the state: decisions on who receives support, who pays for it (and what form it takes) are more likely to be taken so as to minimise the cost of complying with targets rather than on equity grounds. Normally such distributional decisions obtain legitimacy through the political process.

If, as discussed above, there are market failures, resulting in underinvestment in energy efficiency, a much better approach would be for the government to use a tax or even a subsidy to ensure that prices reflect the true economic cost. Where, for whatever reason, reflecting the economic cost in the price is unlikely to achieve the desired goal because of specific market failures, then the government would still be in the best position to choose the most cost effective way to invest revenue in promoting energy efficiency. A regime where obligations are imposed on suppliers is likely to be much less cost effective. It also disguises the true cost to society of the energy efficiency regulations and the distributional effects may well be perverse – as shown for the UK by Chawla and Pollitt (2013).

Increasing the energy efficiency of the residential housing stock can, according to the European Commission, make a significant contribution to the overall reduction of CO<sub>2</sub> emissions in Europe; in fact the European Commission estimates that by 2050 emissions from the residential building stock may have decreased by 90 per cent (European Commission, 2011). Achieving such a reduction in CO<sub>2</sub> emissions from buildings will require significant investment. Given the costs associated with improving the energy efficiency of the housing stock, an

important question is whether homeowners and renters are willing to pay for this increased energy efficiency.

Hyland *et al.* (2013) is the first study to investigate this issue for Ireland. Previous international research on this topic has generally shown that buyers and tenants are willing to pay higher sales prices and rental rates for more efficient properties. The international literature also finds that buyers are willing to pay a significantly higher premium than renters for improved energy efficiency. The authors find that positive building energy ratings (BER) increase both sales and rental prices, and the effects are stronger when the market is worse for sellers. See Box F for more details.

While providing consumers with better information on their electricity usage has been shown to reduce consumption, Faruqui *et al.* (2010), less is known about how this might affect longer term investment behaviour. In a recent working paper, McCoy and Lyons (2014b) use data from the CER Smart Metering Customer Behavioural Trial to examine how exposure to improved information on electricity usage and time-of-use pricing can affect households' behaviour. This study shows that people may be inconsistent in their response to price signals and policy interventions may have unintended consequences. This highlights the need for more empirical evidence in order to make informed decisions when trying to address the energy-efficiency gap.

The new regime imposing energy efficiency obligations on energy suppliers is likely to involve unnecessary costs for society, even taking account of any benefits from energy savings. This approach should be discontinued. If cost benefit analysis shows that some subsidies to promote energy efficiency are warranted, these subsidies should be provided directly by the state through a scheme that targets the areas of market failure where the return to society on additional public expenditure is likely to be highest.

A policy that highlights the energy costs of buildings is effective in improving price signals. As knowledge of the effect of positive BER ratings on sale and rental prices becomes more widespread, consumers may have an increased incentive to invest in energy-efficient technology. However, the effect is much stronger on sale prices than on rentals, suggesting that incentives for rental properties are muted.

**BOX F: The Value of Domestic Building Energy Efficiency – Evidence from Ireland***Marie Hyland*

Hyland et al. (2013) estimate the effect of improved energy efficiency on the sale and rental prices of properties in the Republic of Ireland using data on over 1.2 million property listings on property website daft.ie. Of these listings, approximately 36,000 give information on the energy efficiency of the property, as revealed by its building energy rating (BER) certificate. As of January 2009, any property offered for sale or to let is obliged to have a BER. Our analysis shows what types of properties are more likely to have, and to advertise, a BER certificate, and the effect of these certificates on the sales price and rental rates of Irish properties. The analysis controls for other dwelling characteristics, such as location (county), number of bedrooms and bathrooms and type (detached, apartment, etc.).

Three main results emerge from our analysis, as discussed below.

**1. A POSITIVE ENERGY RATING HAS A POSITIVE EFFECT ON SALES PRICES**

Our results show that energy efficiency is capitalised in house prices: relative to obtaining a D energy rating, an A-rated property receives a price premium of 9.3 per cent, and a B rating increases the price by 5.2 per cent. At the other end of the scale, receiving an F or G rating reduces the price by 10.6 per cent relative to D-rated properties, ceteris paribus. If the BER is measured as a 15-point scale from A1 to G, we find that each rating decline along the BER scale is associated with a reduction in price of 1.3 per cent. Results are shown in the third column of Table 5.

**2. A POSITIVE ENERGY RATING HAS A POSITIVE EFFECT ON RENTAL PRICES**

We find that while the magnitude of the effect is weaker in the rental market, a positive relationship still holds between energy ratings and rental prices. Relative to D-rated properties, A-rated properties experience rental rates that are 1.8 per cent higher. Relative to D-rated properties, E-rated properties receive a rental price that is 1.9 per cent lower and F- or G-rated properties experience a price discount of 3.2 per cent relative to comparable D-rated properties. Modelling the BER as a continuous variable we find that each decline in energy efficiency along the BER scale is associated with a decline in rental price of 0.5 per cent. Results are shown in the second column of *Table 5*.

**TABLE 5** The Effect of Energy Efficiency on House Prices and Rental Rates

	Sales	Lettings
BER label score:		
A	0.093	0.018
B	0.052	0.039
C	0.017	-0.006 <sup>n/s</sup>
D	<b>Reference Category</b>	
E	-0.004 <sup>n/s</sup>	-0.019
F/G	-0.106	-0.032
Decline in BER scale (continuous)	-0.013	-0.005

*Notes:* The results above represent (1) the percentage price premium associated with energy efficiency, as measured relative to a base category, i.e., a D-rated property, and (2) the percentage price discount associated with each drop along a continuous scale measured from A1 to G.

<sup>n/s</sup> implies that the estimated price premium is not statistically significant. All other coefficients are significant.

**3. THE EFFECT OF THE ENERGY RATING IS STRONGER WHERE SELLING CONDITIONS ARE WORSE**

The above estimates are for the full sample of properties listed on the daft.ie website from January 2008 to March 2012. In the next part of the analysis we divided this data into a number of subsamples to

investigate whether the impact of energy efficiency was stronger under more difficult market conditions. We first compared the relative impact of energy efficiency across time by dividing the data into an earlier and later time period. We found that in the later period, when selling conditions were worse, the premium associated with improved energy efficiency increased. Each improvement along the BER scale is associated with a 2 per cent increase in the sales prices in the later period, compared to a 1.5 per cent increase in the earlier period. These results are shown in *Table 6*.

**TABLE 6** The Effect of Energy Efficiency on House Prices and Rental Rates under Different Market Conditions

	Sales	Lettings
<i>Sub-model 1:</i> 2009-2010Q2	-0.015	-0.008
vs. 2010Q3-2012Q1	-0.020	-0.006
<i>Sub-model 2:</i> Urban	-0.012	-0.008
vs. Rural	-0.023	-0.006
<i>Sub-model 3:</i> 1-2 bed	-0.023	-0.009
vs. 3 bed	-0.017	-0.007
vs. 4-5 bed	-0.016	-0.004

*Notes:* The results above indicate the percentage drop in property prices associated with each decline along the continuous BER scale from A1 to G. All estimates are statistically significant.

The positive effect of energy efficiency under tougher selling conditions is confirmed by looking at other subsamples. We find that the price premium associated with increased energy efficiency is greater in the rural market (where it is 2.3 per cent), compared to the urban market (where the premium is 1.2 per cent), and greater for smaller, relative to larger, properties.

According to the Sustainable Energy Authority of Ireland (SEAI), energy efficiency certificates will "...allow buyers and tenants to take energy performance into consideration in their decision to purchase or rent a home" (from FAQs on BER certificates); in this paper we have confirmed that buyers and tenants do place a positive and significant value on increased energy efficiency. However, our research also showed that, for the time period analysed, compliance with mandatory BER labelling appeared to be low – this may now have improved since new BER legislation came into effect in January 2013. The new legislation states that not only must properties offered for sale or to let have a BER, but that the BER grade must be stated in the property advertisement.

Much international research has focused on what is known as the energy-efficiency gap; this is a phenomenon whereby people appear to underinvest in energy-efficiency measures that would, in the long run, save them money. The effects that we estimated in our research could be used by policymakers to encourage homeowners to improve the energy efficiency of their properties, in the knowledge that increased energy efficiency will boost the market value of their property. However, more precise estimates of the energy cost savings associated with more efficient properties would be useful to tell whether or not the increased energy savings are fully capitalised in property values.

### 5.4.1 Information Campaigns

Reducing overall greenhouse gas emissions implies modifying residential energy consumption patterns. This is especially true for countries in the European Union, which have adopted fairly stringent emissions targets. Early literature that finds positive campaign effects focused on cases where households were offered monetary incentives to decrease consumption, either through time-varying prices or subsidies to acquire more energy efficient appliances or improve insulation (Goldman *et al.*, 2010; Gillingham *et al.*, 2006).

Gillingham *et al.* (2006) point out that persuasion and information campaigns promoting energy efficiency account for a very small part of the overall spend on demand-side management and are, therefore, likely to be responsible for small savings.

For programmes that do not provide monetary incentives, the evidence is mixed. Recent analyses of a set of randomised experiments set up by OPOWER in the United States show a reduction in electricity use of about 1.5 to 2 per cent (Allcott, 2011; Ayres *et al.*, 2012). In these experiments households were told how their energy consumption compared to that of similar households. Costa and Kahn (2013) suggest that the decrease was not uniform and consumers' pre-existing attitudes mattered: consumers who tend to be more liberal and have a higher interest in environmental issues decreased consumption after the OPOWER intervention, whereas the opposite was true for more conservative consumers. The explanation is that conservative consumers may not trust the comparative figures provided by the utilities. Allcott and Rogers (forthcoming) suggest that the effect of the OPOWER intervention decayed slowly. After two years of repeated information on comparative consumption, the effect decreased by about 10 to 20 per cent per year.

There is also mixed evidence of changes in behaviour following other state-level advertising campaigns focused on environmental issues. Staats *et al.* (1996) find no effect on behaviour of a Dutch campaign aimed at raising awareness of greenhouse gas issue. Reiss and White (2008) show that households in San Diego reduced their electricity consumption by 7 per cent over a six month period in response to public appeals. Cutter and Neidell (2009) observe that appeals to limit air-polluting travel at times of high ozone were somewhat effective in San Francisco.

How can advertising campaigns affect consumers' behaviour? One option is by increasing consumers' knowledge, which allows consumer to take better

decisions. Jessoe and Rapson, 2014, have recently suggested that informed consumers react more to changes in energy prices. Consumers can also be influenced by social norms, although this influence may be short lived (Nolan *et al.* 2008). One explanation of why social norms are important is that knowing peers' behaviour may be useful in the face of uncertainty. In particular, few households have a good sense of how much energy they use to heat and power their houses, so seeing that others can run a household using less energy provides useful information. For a general overview of this area, see Pollitt and Shaorshadze (2013). Another view, based on behavioural economics, argues that how the message is framed can be as important as its substance (Bertrand *et al.*, 2010).

Most of the recent studies refer to data from the United States. This is important since a large portion of the elasticity of electricity consumption in the US appears to derive from changes in air conditioning use, something that is not relevant in Ireland. In Central and Northern Europe air conditioning use is limited and, therefore, cannot be significantly curtailed. Box G provides details of an Irish advertising campaign to encourage energy-efficient behaviour.

The international literature shows that information campaigns, paired with peer effects, can decrease residential energy consumption. Most of the evidence is for countries with widespread air conditioning use. Total decrease in electricity use is of the order of 2 per cent on average. Two conclusions can be made. First, while this is a significant change, it would not on its own allow Ireland to meet the goal of decreasing energy consumption by 20 per cent by 2020. Second, in order to identify changes of this magnitude, large amounts of energy consumption data by household should be collected. Any further campaigns in countries of Northern Europe should be accompanied by careful and extensive collection of information on household consumption behaviour before and after the onset of the campaign.

#### **Box G: Information Campaigns: The Case of Ireland**

*Laura Malaguzzi Valeri*

In 2006 the Irish government launched the Power of One campaign to encourage energy-efficient behaviour. The campaign targeted use of natural gas, electricity and transport fuel (petrol and diesel) both at home and at work.

Diffney *et al.* (2013) focused on the effects of the campaign on natural gas consumption in the residential sector. Residential consumption of natural gas is mainly for heating. The campaign provided numerous tips on how to save electricity. The message relevant to natural gas consumption was that reducing the thermostat by 1 degree Celsius could reduce heating bills by up to 10 per cent.

The authors found that the campaign increased consumers' awareness of the potential savings associated with lowering the thermostat. This, however, did not translate into persistent changes in behaviour within the time frame of the data, available until the end of September 2008.

Decreasing household energy use is essential if Ireland is going to meet the lower energy use targets set by the European Union for 2020. Studies that measure the impact of government programmes are valuable. They can identify which measures have been most effective thereby helping the government allocate its limited resources efficiently. Evaluation of any programme is easier when consistent data are collected before and after its implementation.

#### 5.4.2 Electric vehicles and demand response

As outlined in earlier research (Driscoll *et al.*, 2013), it is highly unlikely that electric vehicles (EVs) will become widespread in the near future, unless costs drop significantly or subsidies are raised to very high levels. The government target of 10% market penetration of EVs (230,000 vehicles) by 2020 seems unrealistic considering there are approximately 350 EVs in Ireland today.

However, even if aggregate adoption remains quite low, it could be concentrated in relatively few areas. An interesting question concerning EVs over the medium term is where the early adopters are likely to be located. A large engineering literature documents the negative effects that clustering of electrical load and uncontrolled charging of large numbers of EVs could have on low-voltage distribution networks (Schneider *et al.*, 2008; Shao *et al.*, 2009; Richardson *et al.*, 2010a). This is a very live issue; ESB Networks has recently received regulatory funding approval to engage in a €25 million study to investigate the impact this might have on the distribution network (CER, 2014b).

To identify the areas where we might expect large concentrations of EVs, it is important to understand the characteristics of early adopters of EVs and their spatial distribution. If peer effects exist in technology adoption, this could result in clusters forming in certain areas.<sup>34</sup> McCoy and Lyons (2014a) use agent-based models to generate spatially explicit adoption profiles in order to assess where clusters might form. Even mild peer effects may induce significant clusters, given the spatial distribution of likely early adopters. This could lead to increased costs for electricity network operators and ultimately for consumers, as the average cost of improvements to the network will be socialised.

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<sup>34</sup> Peer-effects or spatial dependencies occur when an individual's behaviour is influenced by that of his or her neighbours. There is empirical evidence to suggest that this effect exists in the adoption of "green" technologies.



The market share of electric vehicles is likely to stay below the 10 per cent penetration target by 2020. Even limited adoption might strain the electricity grid if it is concentrated within a narrow geographic area. Additional costs needed to reinforce the distribution grid should be part of any cost benefit analysis of electric vehicle adoption.

#### 5.4.3 Effect of Moving from Variable to Fixed Electricity Component Charges

Electricity consumers in Ireland pay a mixture of fixed and usage-related charges for the services they receive. This split broadly reflects a mixture of fixed and variable costs incurred by generators, network operators and suppliers. Network costs, in particular, tend to vary little with marginal changes in output, whereas costs of fossil fuels used relate directly to the level of electricity generation.

EU and national policies aimed at decarbonising the energy system and improving energy efficiency are bringing about significant changes in the cost structure of the electricity system. While much discussion of policy costs and benefits tends to focus on whether overall costs rise or fall, it is also important to consider if changes in the charge structure unfairly affect some groups of consumers more than others. These effects on *distributional equity* can be considered for a single service, such as electricity, or they can be embedded in wider discussions of poverty, deprivation or national tax and benefit policies.

The electricity sector is experiencing a shift from variable to fixed cost components, driven by three inter-related factors. First, the share of renewable generation is increasing rapidly. Renewable energy technologies, such as wind and solar power, require a big upfront commitment of capital, but then provide energy at little incremental cost. Some countries also offer renewable energy subsidies through mechanisms such as guaranteed minimum feed-in tariffs. Funding for such supports is normally paid for by charges levied on consumers. Costs associated with such policies can be significant; for example, in 2014 Germany's Renewable Energy (EEG) surcharge is over €0.06 per kWh.<sup>35</sup> Second, in many countries (including Ireland), the main sources of renewable electricity are distant from sources of demand, which implies a need to invest further capital in reinforcing transmission and distribution networks. A third, rather different, contributing factor arises from policies in some countries imposing

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<sup>35</sup> EEG surcharge for 2014, Press release, 15 October 2013, URL:  
[http://www.50hertz.com/en/file/\\_726\\_\\_TARGET\\_EN\\_20131015\\_Pressemitteilung\\_EEG-Umlage\\_2014\\_50Hz\\_Amprion\\_TenneT\\_TransnetB.pdf](http://www.50hertz.com/en/file/_726__TARGET_EN_20131015_Pressemitteilung_EEG-Umlage_2014_50Hz_Amprion_TenneT_TransnetB.pdf)

obligations on electricity suppliers to implement special low tariffs for vulnerable energy consumers and cross-subsidies to support residential energy efficiency policies (e.g., subsidised home energy upgrades).<sup>36</sup> Cross-subsidies such as these imply that increased revenue is required from some consumers to pay for the benefits provided to others, although the flows of funding may not always be transparent to customers or outside observers.

The net effect of these changes is to shift from a traditional system, where fuel costs were a significant component of total cost, to one where network charges, capital cost recovery for wind turbines, renewable energy subsidies and various social cross-subsidy measures together make up a growing proportion of the total final cost of electricity services.

Depending upon how these changes in cost structures are reflected in consumer prices, they may affect energy affordability for some groups differently from others, regardless of whether the overall cost of the system rises or falls. For example, if a larger share of costs was levied on a per household basis, rather than proportional to usage of electricity, small households or those with low incomes would tend to bear relatively more of the cost burden. If these changes become large enough, policymakers may wish to make policy changes to preserve affordability for vulnerable groups or maintain other social and distributional objectives. Policy responses could involve changing electricity charging structures directly, or adjusting a wider set of tax and benefit measures.

To illustrate this issue and give a feel for the scale of distributional consequences that may arise, we discuss the example of Ireland's Public Service Obligation (PSO) levy. The PSO levy is an additional charge on all consumers' electricity bills to provide a price support for renewable energy, peat generation and some security of supply provisions. Revenue from the PSO levy must be sufficient to pay these parties the difference between their guaranteed price and the wholesale electricity price.

For domestic consumers, the entire PSO levy for the 12 months from October 2013 to September 2014 is set at €42.87 per customer, a rise of 54 per cent relative to the period between October 2012 and September 2013. Although

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<sup>36</sup> See e.g., Chawla and Pollitt (2013) discussing the scale and distributional effects of such measures in the UK.

such a large increase is unlikely to take place every year, the PSO is expected to grow in the future due to a number of factors.

The PSO requirement may grow as renewable electricity generation (especially wind) continues expanding. A higher penetration of renewables affects the PSO through two channels. First it increases the volume of electricity generation that is guaranteed a minimum price. Second, more renewables tend to reduce the marginal price of electricity, thereby increasing the difference between the REFIT price and the wholesale marginal price. The installed capacity of peat generation is unlikely to increase in the near future.<sup>37</sup>

The level of the PSO will also depend on how fossil fuel prices evolve. If fossil fuel prices are low, the wholesale electricity price will also be low, increasing the cost of price guarantees covered under the scheme. The opposite will be true with high fossil fuel prices.

The PSO cost may thus become a greater proportion of each consumer's electricity bill over time. Farrell and Lyons (2014) have assessed how different PSO pricing structures may affect households across the income distribution. They find that the current flat rate is regressive, i.e. it affects consumers with lower incomes more than consumers on higher incomes. They suggest alternative ways of distributing the PSO cost and measure how equitable each is. Schemes that allocate the PSO cost with charges that are proportional to electricity consumption are more equitable. However, attention must be paid to protect vulnerable groups, such as low income households with relatively high electricity consumption. For details see Box H. Note that, while this discussion focuses on PSO costs, similar reasoning applies to all fixed costs that are billed to final consumers, for example the costs of reinforcing the transmission and distribution grid. We understand that the current practice in Ireland of recovering PSO costs via a flat rate per account was chosen to meet state aids concerns about the competitive effects of programmes funded by the PSO. However, there are other ways to mitigate any distortions such supports may make to competition.

The rising penetration of wind is likely to increase the size of the Public Service Obligation Levy, making it a larger portion of consumers' electricity bills. Other fixed costs are also likely to grow, for example to finance the reinforcement of

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<sup>37</sup> Peat fired electricity is also supported by the PSO when it fails to make enough money on the market.

the transmission and distribution grid. Policymakers should therefore focus on equitable ways to distribute these costs, with particular attention to protecting vulnerable groups.

#### Box H: Incidence of PSO Levy Cost<sup>38</sup>

*Niall Farrell*

The current PSO levy has a flat-rate structure, whereby every household, regardless of income or electricity use, incurs the same levy. This flat rate is a higher proportion of a poorer than a wealthier household's income. The PSO 'burden', or cost of the PSO levy relative to income, is 12 times larger for the households in the lowest income decile than for the average of the five wealthiest income deciles.<sup>39</sup>

Switching the PSO to a levy incurred per unit of consumption shifts some of the PSO cost to households that use more electricity. Wealthier households tend to use more electricity, with the result that the average cost to income ratio falls for the bottom three income groups. Income groups in the second and third decile face a burden that is similar in magnitude to that of the population as a whole under this option. However, the burden for the lowest income group is still disproportionately large.

The impact of 'Incremental Block Pricing' (IBP) is also analysed. IBP levies the PSO cost on a per-unit basis, with different prices applied for different levels of consumption. As consumption increases, it is associated with higher per unit prices. A low per-unit levy applies to an initial 'block' of units up to a given threshold, with a medium levy for the second 'block' and a high per-unit levy for all remaining units consumed. This levy design shifts incidence to heavy users to a greater extent than a fixed per-unit pricing structure. This causes the incidence for the lowest three income deciles to become closer to that of the population as a whole.

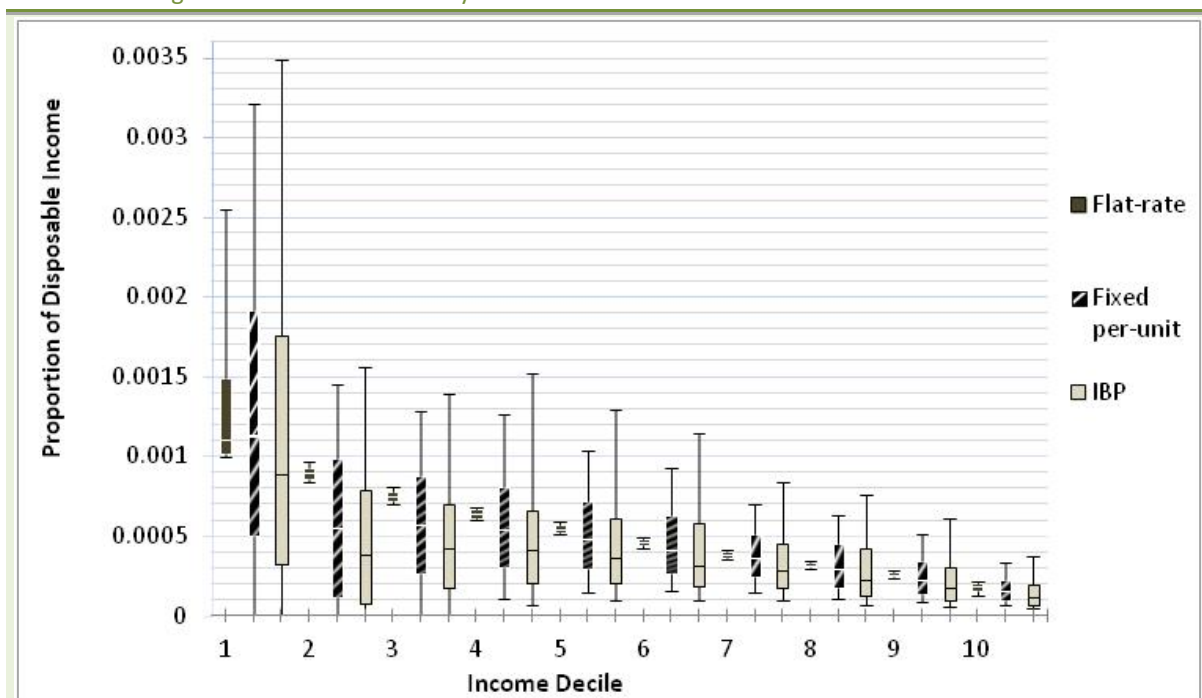
Although most heavy users are in higher income groups, there are some households in low income groups that use a lot of electricity. Figure 1 shows the range of incidence for each income group, where incidence is defined as the PSO cost as a share of disposable income. Incidence amongst households is displayed by boxplot diagrams. The boxes represent the interquartile range, or the incidence range for the 50 per cent of households between the 25<sup>th</sup> and 75<sup>th</sup> percentile in each income group. The tails represent the 10<sup>th</sup> and 90<sup>th</sup> percentiles, or households at the extremes of the incidence within each income group. There are three plots for each income decile, representing the incidence of the flat rate, the per-unit range and the incremental block rate respectively. Although the interquartile range falls when moving from flat to a fixed per-unit or IBP levy, the upper tails increase, indicating that the majority benefit from the change but a subset lose out. This occurs to a greater extent for the first income decile. Farrell and Lyons (2014) identify these households negatively affected by a switch to a unit-based change in the first decile. Those who use more than 100kWh/week incur a greater cost. To put this into perspective, the median level of electricity use across all income groups is 85 kWh/week. Large

<sup>38</sup> This box focuses on the REFIT portion of the PSO levy. When considering the entire PSO levy, the magnitude of results will differ but the distribution of incidence will be very similar.

<sup>39</sup> The population is split into ten equal groups or 'deciles' according to the distribution of equivalised disposable income (i.e., income net of taxes and transfers, reweighted to account for economies of scale associated with household size).

households and households headed by employed persons or students are amongst those who incur a greater cost. Households headed by retirees tend to consume less electricity than average.

**FIGURE 1** Range of PSO Cost Incidence by Income Decile



Note: Boxplots show range of proportional incidence per decile. Results are displayed in terms of 10th, 25th, 50th, 75th and 90th deciles.

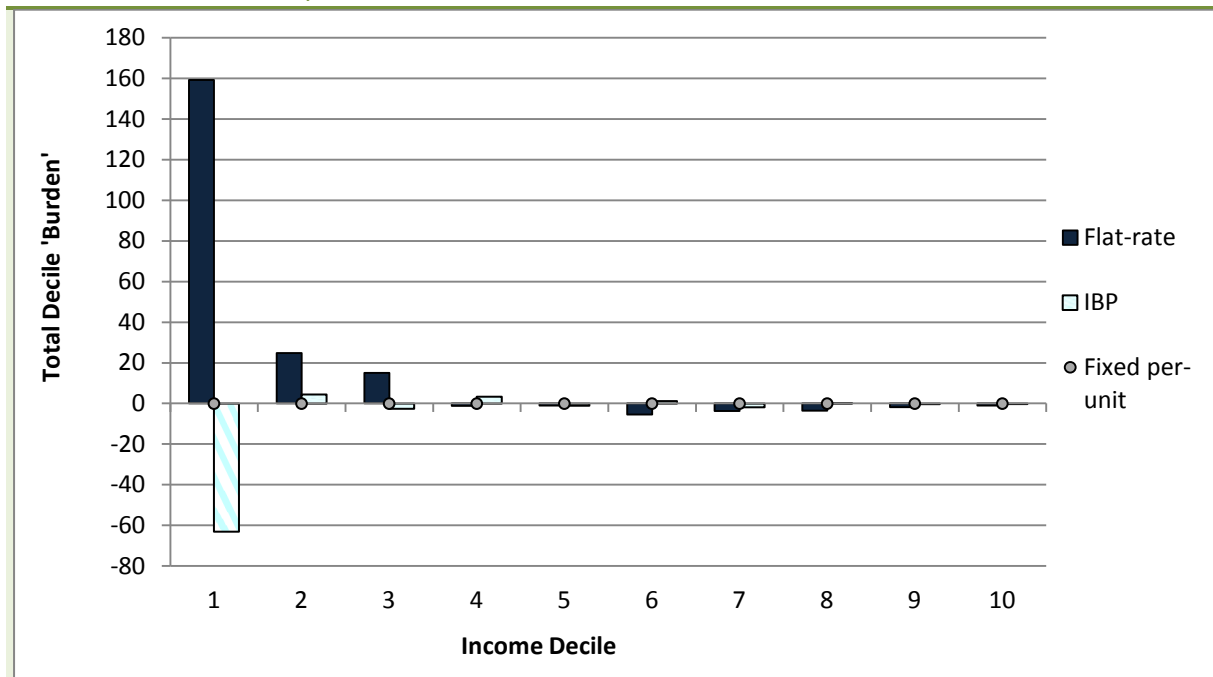
Farrell and Lyons (2014) explore several ways to limit the negative impact of a unit-based policy on low income households. Imposing a 'hybrid' PSO levy, where 50 per cent of the cost is recouped via a flat-rate charge and 50 per cent via a per-unit charge, reduces the impact on heavy users but allows the incidence to stay higher for lower income households.

Existing social transfer mechanisms are only partially effective in reducing the negative impact on this subset of low-income and high consumption households. Changing Ireland's Household Benefits Package (HBP) to cover the PSO charge is effective in reducing the burden for the lowest income group by 41 per cent, but the incidence for the lower income households remains four times greater than the average incidence for all other income groups. The first and second income groups are most negatively affected by the PSO, but only 44 per cent of HBP recipients are located here. Furthermore, HBP is provided to a high proportion of retired individuals and a low proportion of students and employed persons, indicating that this scheme targets households that are less likely to lose out due to a switch to a unit-based scheme. A policy instrument that specifically targets households based on income and electricity use would be most effective.

As mentioned earlier, wind reduces the wholesale price of electricity. If we assume that wholesale price reductions are passed on to consumers, part of the PSO increase is compensated for by lower electricity prices. Focusing on the REFIT portion of the PSO, Figure 2 reports the 'burden' of each PSO levy net of the price reductions that are expected as a result of wind deployment. The current flat-rate PSO levy applies equally to all households whilst market price reductions are distributed according to use. Those on lower incomes incur the same cost as those on higher incomes, but tend to use less electricity and thus receive

less of the price-reducing benefits. When moving to per-unit pricing schemes, high income groups incur a negligible net burden, whilst low income groups incur a net cost for the flat-rate scheme, but a net benefit (i.e. a negative burden) in the case of the IBP structure. Ignoring the magnitude of benefits versus losses, most households, across all income groups, benefit with an IBP scheme. However, an IBP scheme achieves this by shifting an even greater burden on to heavier users. If such a system were adopted, an effective social transfer mechanism would be necessary to obtain an equitable PSO structure.

FIGURE 2 Total 'Burden' by Income Decile



Note: Burden is calculated as PSO cost divided by disposable household income. Results displayed relate to the REFIT portion of the PSO alone. Figure source: Farrell and Lyons (2014).

# Chapter 6

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## Implications for Policy

This section brings together the policy conclusions from the rest of this Report. They address policy at both the EU and national level.

In addition to considering the traditional challenges for energy policy (tackling climate change, maintaining a secure energy supply and delivering the required energy at a minimum cost to consumers) we focus on the distributional effects of policy. Too often these distributional effects are ignored in spite of their importance: energy policy can have a major effect in redistributing income between countries; between consumers and producers and between rich and poor households. These distributional consequences, which may be large in size, need to be taken into account by future policymakers.

### 6.1 POLICY PRIORITIES

At an EU level Ireland should work continuously to improve EU policymaking on climate change. The use of quantity-based targets rather than price instruments to achieve desired policy goals, has a number of drawbacks. Where the quotas or targets are applied at a national level, rather than at an overall EU level, they can give rise to major transfers of resources between countries over the course of the planning horizon, transfers that were neither planned nor expected by all countries involved. If quantity based targets are to continue as the mainstay of climate and energy policy at an EU level, there must be safeguards put in place to ensure that they do not result in major transfers of wealth between EU members at a future date. In addition, where quotas are used as a policy instrument, they should always be auctioned to ensure that there are no windfall gains for producers, benefiting producers at the expense of consumers.

While Irish governments cannot influence policy in the UK, policymakers in Ireland must be cognisant of the uncertainty about UK energy policy. Irish policy must also be formulated so as to be robust whatever the decision by the UK about its future EU membership.

This Report has considered many facets of energy policy in Ireland. However, there are some areas of particular importance for the future welfare of citizens.

One of the most pressing areas for policy is the development of the Single Electricity Market to conform to EU rules on trading across countries. While there are significant gains to be obtained from a reform that allows increased trading, research described in this Report suggests that the current proposals for a new regime could result in significantly higher prices for Irish consumers than under the current regime. This would be a very unsatisfactory outcome, with serious consequences for Irish competitiveness and living standards. Unfortunately, current research, while identifying weaknesses in the current proposed reforms, does not give a clear guide as to how it can be improved. Under these circumstances the correct approach is to delay making a decision and, in conjunction with the EU, to seek to identify a more appropriate model that will be likely to benefit consumers in Ireland and elsewhere in the EU.

A major task for energy policy over the coming decade will be to deliver on the appropriate physical infrastructure to allow the objectives of Irish energy policy to be met.

- This task has an important financial dimension. Because of the large sums needed for the investment, policy needs to help ensure that the cost of the necessary finance is minimised. This means that policy makers should try to reduce any unnecessary uncertainty around such investment, especially with respect to the regulatory environment.
- There is also a major task for policymakers in ensuring an efficient planning process that helps to promote buy-in from all parties involved in the investment process. Further research into how best to accomplish this task is needed.
- Examples of key pieces of infrastructure that are important for Ireland's future development and that can help reduce greenhouse gas emissions are: the North- South electricity interconnector; further interconnection between the Irish electricity system and the rest of Europe; bringing the Corrib gas field into production.

There are many opportunities to reduce energy use through increased energy efficiency. The first task is to ensure that economic incentives are appropriate to encourage an optimal level of investment. However, because of market failures, price signals on their own may not be sufficient to reach an appropriate level of investment. Instead policy needs to take account of lessons from behavioural economics to help households and companies find the right solution for their individual circumstances.

Experience elsewhere suggests that bad investment decisions can be made where new technologies are moved from the research phase to the development phase



before they are fully developed. This can see countries locking into new technology at much too high a price. The extensive deployment of onshore wind in Ireland has taken place after a major fall in the cost of the technology. If major investment had taken place prematurely in the 1990s Ireland would have been saddled with a very high cost base. This lesson must be taken on board when considering the deployment of other new technologies, such as offshore wind and wave power. Until their costs have fallen to make them competitive, they should remain in the domain of research and that research should be funded by the tax-payer rather than by energy consumers.

Finally, job creation is not, and should not be, the objective of energy policy. Instead the objective should be to deliver a secure and environmentally friendly energy supply to Irish consumers at a minimum cost. Naturally, the energy sector will be a significant employer for the foreseeable future, but the task of tackling Ireland's unemployment problem should be left to macroeconomic and industrial policy.

## 6.2 EXTERNAL DRIVERS OF POLICY – THE EU

Because of the capital intensive nature of the energy sector it is important to provide clarity about EU policy out to 2030 as soon as possible. Policy uncertainty is costly for investors and will result in an unnecessarily high cost solution to the crucial problem of reducing greenhouse gases. It will also delay progress in reducing emissions.

While it is important to set targets for reducing EU emissions over the period to 2050, these targets should not be enshrined in law. Instead, using suitable models, an appropriate trajectory for the price of carbon should be chosen and this price should be what is enshrined in law. This would mean the EU moving away from using the Emissions Trading regime towards using an explicit price, either as a carbon tax, or at least as a carbon floor along the lines of the recent UK policy initiative.

The current approach of using a combination of policies – setting national targets for emissions in the non-ETS sectors and then using an ETS scheme for other sectors – has proved inefficient. This regime is not transparent: consumers and tax payers are not told what the price of the policy is up front. While it may help produce initial agreement to the policy by disguising what it involves in terms of costs, it does not contribute to decisions that are efficient in the long term. It also has the potential to result in unpredictable but large transfers from consumers to

producers, or between countries, transfers that have no justification in terms of economic efficiency or equity.

Moving EU policy away from targets for renewables makes sense as the current regime has proved an expensive way of reducing greenhouse gas emissions. It would have been better if more funding had been put into research to develop cheaper renewable technologies and less into subsidising the deployment of existing expensive technologies. For the future, if an appropriate regime is implemented at EU level to incentivise a reduction in greenhouse gas emissions, this regime should, on its own, provide appropriate incentives to deploy renewable technologies. Then the market will decide on the cost-minimising way of meeting the objective of reducing greenhouse gas emissions.

Ireland would likely benefit from further investment in interconnection with foreign electricity markets over the coming decade. While, to date, all investment has been designed to link Ireland and GB, the uncertainty about future GB energy policy makes enhanced interconnection to France, albeit at higher cost, a possible option that policymakers should consider.

Provided that there is adequate use of interconnectors they should be paid for by fees proportional to the traffic through the interconnector.

The move to develop an integrated EU electricity market is to be welcomed. In the long run it is likely to prove of substantial benefit to Ireland and other member states. It will require some changes in the Irish market, a market which has proved successful in providing a secure electricity supply at close to minimum cost.

Developing EU wide trade in renewable energy would make sense both for potential Irish producers and also for GB consumers.

### **6.3 EXTERNAL DRIVERS OF POLICY – THE UK**

With extensive interconnection between Ireland and the GB market, the presence of a carbon floor in the GB market will exert an influence on prices in Ireland. This will tend to transfer resources from consumers (household and industrial) to energy producers in Ireland, as Irish prices would rise. This transfer of resources to producers would be in the nature of a windfall gain. Under these circumstances it would probably be better if the Irish government imposed a

similar carbon floor in Ireland to that in GB. This could add further to prices in Ireland but, in this case, all of the transfer of resources would go from the consumer to the government, who could then return the revenue to the household or company sectors through other fiscal measures. If a carbon floor were introduced in the North of Ireland then it would be important that a similar floor was imposed in the Republic of Ireland to avoid a substantial transfer of resources from Irish consumers to the UK Treasury.

Any strategy by the Irish authorities that would help reconcile the UK to its EU partners would be important, given the very serious consequences for Ireland of a UK exit. Until the UK decides on its future membership of the EU, all major energy policy decisions in Ireland need to be tested against the effects of differing outcomes on UK membership of the EU. This also applies to investment decisions, where future reliance on EU law may not provide adequate protection for Irish interests.

#### 6.4 DOMESTIC POLICY – GAS

The Irish gas interconnection infrastructure should be treated as part of the transmission infrastructure and priced accordingly. The pricing of this infrastructure should not be used to further other policy objectives. If necessary, other policy tools can be used to encourage measures that would enhance security.

For security of supply reasons the development of the Corrib gas field should be completed as soon as possible.<sup>40</sup> Thereafter, it will be important to develop a strategy to replace Corrib once the field begins to run down, in the early years of the next decade.

#### 6.5 DOMESTIC POLICY – ELECTRICITY

Any changes to the SEM need to guard against potential abuses of market power. The proposal to replace the current wholesale electricity pool, which is working fairly well, with a new day-ahead market needs further testing.

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<sup>40</sup> It is the ready availability of gas from Corrib which is important. The security benefits could, theoretically, be obtained if Corrib was brought to a stage where it could produce gas at very short notice, while still leaving most of the gas in the ground.

The proposal to replace the current capacity payments system with a new approach looks vulnerable to abuse through use of market power. On this basis, the existing SEM regime looks preferable to the CER's current alternative. However, this issue also merits further research.

Given that we have a market that works fairly well, it will be important to establish, with reasonable certainty, that any new market will not only remedy the problems encountered with the current market (e.g., interconnector flows), but that it will also maintain all the advantages of the SEM. It needs to be clearly demonstrated that the new market will produce lower costs for consumers in the long term. Consideration also needs to be given to the transactions costs involved in developing a new market structure.

Independent of the new SEM market, it is important for all electricity users on the island that the strengthening of the North-South transmission infrastructure is completed quickly. Its absence is imposing significant costs on consumers across the island and these costs are likely to rise over time. In addition, after 2016, the absence of enhanced interconnection will put the security of electricity supply in Northern Ireland at risk.

With increasing deployment of wind it may be appropriate to modify the REFIT scheme so that price risk is efficiently divided between investors and consumers. The current regime puts consumers at risk of paying for high subsidies if electricity prices are low and it does not allow them to receive any market upside if electricity prices are high. Any future REFIT arrangements should be modified to take these factors into account. In addition, it is important to provide a mechanism to ensure that the deployment of wind generation does not exceed the ability of the Irish system to efficiently absorb the electricity generated.

The absorptive capacity of the Irish system depends in part on the level of interconnection to the outside world. Diffney *et al.* (2009) suggest that if Ireland is to reach its target for deployment of wind by 2020, it will need to double the current level of interconnection with the outside world. If this does not happen the additional deployment of wind will significantly raise costs for Irish consumers, while providing only a small and decreasing benefit in terms of carbon reduction.

One possible market mechanism to produce an efficient deployment of wind in Ireland would be to turn some of the wind turbines off when they begin to

impose rising costs on the system and to constrain the wind generators off in the reverse order to their initial connection to the system; recent arrivals would be constrained off first, discouraging over-investment. If, instead, the costs of constraining off were socialised across all wind generators then too much wind would be deployed, imposing unnecessary costs on the wind generators that deployed first on the system, as well as on consumers.

The recent proposals for large-scale wind generation in Ireland for export were designed to ensure that there were no net costs for Irish consumers. In assessing their future value for the Irish economy a range of other factors need to be taken into account, such as the opportunity cost of giving up land on which future renewables could be sited.

The stable regulatory regime in Ireland over the last decade has contributed to good decision making by private investors and to minimising the cost of capital used to fund those investments. In developing the electricity and gas markets over the coming decade, it will be important to maintain this approach, providing a stable environment for the large-scale continuing investment needed in the sector.

Energy policy should concentrate on delivering a secure energy supply to consumers at minimum cost. If the necessary investment to produce the energy at minimum cost results in new jobs that is a bonus. However, the jobs content of the investment should not be an objective of energy policy.

## 6.6 DEMAND SIDE

Increases in energy prices can, in theory, affect the competitiveness of firms. Haller and Hyland (2014) show that this effect is likely to be small for Irish manufacturing firms for reasonable changes in energy prices. Energy costs account for only about 2 per cent of overall expenditures; in the long run Irish firms in the manufacturing sector are likely to react to higher energy prices by using slightly more labour and capital in their production process; foreign-owned firms are less likely to adjust their production processes, a result that is consistent with these firms being more energy efficient in the first place.

In order to facilitate the reduction of greenhouse gas emissions from buildings, policy should change the emissions assumptions used in the calculations to use up-to-date parameters and policymakers could consider the option of taking some account of likely future emissions reduction in electricity generation.

The new regime, whereby energy efficiency obligations are imposed on energy suppliers, is likely to involve unnecessary costs for society, even taking account of any benefits from energy savings. This approach should be discontinued. If cost benefit analysis shows that some subsidies are warranted, these subsidies should be provided directly by the state through a scheme that targets the areas of market failure where the return to society on additional public expenditure is likely to be highest.

The policy that highlights the energy costs of buildings is effective in improving price signals. As knowledge of the effect of positive BER ratings on sale and rental prices becomes more widespread, consumers may have an increased incentive to invest in energy-efficient technology. However, the effect is much stronger on sale prices than on rentals, suggesting that incentives for efficiency in rental properties are muted.

The international literature shows that information campaigns, paired with peer effects, can decrease residential energy consumption. Most of the evidence is for countries where there is widespread use of air conditioning. In these cases the total decrease in electricity use is of the order of 2% on average. Two conclusions can be made. First, while this is evidence of a significant change in energy use in the countries examined in these studies, if reproduced in Ireland such a reduction would not, on its own, allow Ireland to meet the goal of decreasing energy consumption by 20 per cent by 2020. Second, in order to identify changes of this magnitude, large amounts of energy consumption data by household should be collected. Any further campaigns in Northern European countries should be accompanied by careful and extensive collection of information on household consumption behaviour before and after the onset of the campaign.

The market share of electric vehicles is likely to stay below the 10 per cent penetration target by 2020. Even limited adoption might strain the electricity grid if it is concentrated within a narrow geographic area. Additional costs needed to reinforce the distribution grid or to facilitate more flexible consumer charging behaviour should be part of any cost-benefit analysis of electric vehicle adoption.

The rising penetration of wind is increasing the size of the Public Service Obligation Levy, making it a larger portion of consumers' electricity bills. Other fixed costs are also likely to grow, for example, to finance the reinforcement of the transmission and distribution grid. Policymakers should, therefore, focus on equitable ways to distribute these costs, with particular attention to protecting vulnerable groups.

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ISBN 978 0 7070 0372 6