The Irish Energy Tetralemma

Fuel Report 1: Coal

August 2010

Forfás

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This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ Coal is the most competitive fossil fuel on the basis of fuel cost (on a par with peat) in Ireland and internationally. ▪ There is no single price for coal: there are many varieties of it, and they are physically and financially traded in several markets. Internationally traded coal is known as steam coal and it mainly comprises bituminous coal and a small fraction of anthracite.Lignite is low-density, high-volume coal which is not currently viable for imports (including to Ireland) in large quantities. Depending on the future price, availability and access to other fossil fuel, lignite could become viable for imports to Ireland. ▪ Using an average of World Bank, US EIA[1], IEA[2], and EU[3] real price forecasts, coal is predicted to remain relatively inexpensive and either maintain or lose its value in real terms: €1.51/GJ in 2010, €1.38/GJ in 2020, €1.41/GJ in 2030. ▪ Ireland does not have any indigenous coal reserves and buys coal at the international market price – currently and in the future. This means that the country is exposed to potential fluctuations in the market price of coal.
Delivered energy cost	▪ Coal is currently the cheapest source of energy in the energy mix in Ireland and internationally (matched only by nuclear). ▪ As of early 2010 delivered cost of energy from coal (defined as the levelised cost of generation) is approximately €30-35/MWh, approximately 3.5 times cheaper than wind.This is based on current subcritical pulverised coal combustion. ▪ The future competitiveness of coal largely depends on the development and deployment of advanced conversion technologies. An ‘optimistic’ scenario where technologies such as supercritical, ultra-supercritical and Integrated Gasification Combined Cycle (IGCC)

1 United States Energy Information Administration

2 International Energy Agency

3 European Union

	become widely used, still shows the real delivered cost almost doubling by 2030 (due to their high capital cost). By that time, coal will lose its relative competitiveness with respect to natural gas and renewables such as hydro and bio-gas, but will still be cheaper than mainstream renewables, e.g. wind and woody biomass. ▪ The market price of carbon dioxide can have a considerable impact on the competitiveness of coal-based generation (which is very carbon-intensive). Carbon capture and storage (CCS) is seen as both an opportunity (to generate extra revenue) and cost (as it has a significant capital and operational cost). Ireland has very good potential for deploying and operating CCS schemes. Developers will only invest in CCS if it is financially viable (a combination of appropriate carbon price and public sector funding) and therefore CCS will have a broadly neutral effect on the delivered cost of energy from coal. ▪ Given that there is only one coal-fired plant in Ireland (Moneypoint, 915 MW capacity) which is expected to operate at least until 2020, any future capacity developments are likely to employ advanced technologies and in particular with CCS capability (subject to CCS becoming a fully recognised option). Therefore, the competitiveness of an additional marginal coal plant in Ireland will be as indicated above.
Policy & Regulation	▪ Coal is at a relatively significant disadvantage to other fuels in terms of policy and regulatory barriers and the lack of particular incentives for its use. ▪ At the European level, a range of regulatory obstacles exist to coal power generation including: EU Emissions Trading Scheme (EU ETS), EU Large Combustion Plant Directive and EU Integrated Pollution Prevention and Control Directive. This situation is likely to be compounded for coal with the next phases of the EU ETS and the EU Energy and Climate Package. ▪ Coal's competitiveness in the context of policy and regulation, could improve, especially black coal, if carbon capture and storage (CCS) is supported at the national and EU levels. The EU framework already aims to develop a number of strategic large-scale CCS facilities and the draft proposal for a EU Carbon Capture and Storage Directive will reinforce this, which Ireland can potentially benefit from.

Market context in Ireland	▪ Brown coal is the least attractive option of all fuels because of technical application issues. Black coal is solely used in Ireland. ▪ Market conditions can work in favour or against any new coal-fired generation depending on the developer.

Security of supply

Import dependence	▪ All coal used in Ireland is imported, which makes the country highly import dependent. ▪ However, coal makes up only a relatively small proportion of the total primary energy requirement (TPER), thus reducing the overall ('weighted') import dependence. Black coal's weighted import dependence is 9.4 per cent and brown coal's is 0.04 per cent. Coal will maintain its relative weighted import dependence position in the future, despite a slight decline of its role in TPER.
Fuel place of origin	▪ Coal is available from a large number of exporting countries, which are a mixture of low-risk and high-risk. Choosing and switching the supplier(s) is fairly flexible and easy and therefore coal should score relatively well on this indicator for all three timescales. However in practice in the short term coal supplies are riskier than there are of oil and gas that come entirely from the UK ('low risk'). In 2020 and 2030, black coal supplies to Ireland become more secure than oil and gas (as the latter two fuels become scarcer and Ireland starts to rely on higher-risk places of origin). ▪ Ireland currently imports most of its coal from Colombia. Other major sources include Indonesia, South Africa, Poland, Germany, UK and Netherlands. All brown coal is sourced from Germany. ▪ In the future, Ireland will have diverse options of where to source coal and therefore the risk is difficult to calculate, given that the mix of supplies may change every year depending on political and economic factors.
Supply and infrastructure resilience	▪ Coal's supply and infrastructure resilience is relatively high in general. The supply chain is flexible and not overly complex and the infrastructure is relatively simple and fairly robust.
Market volatility	▪ Coal is typically linked to the oil markets in terms of its price, demand and availability at any point in time. Higher oil prices and supply deficits lead to an increased demand for coal. Nevertheless, coal is rather abundant and as such

	not associated with market crises and spikes. Moreover, it is chiefly sold under long-term, fixed-price contracts, which increase the market security – making it one of the most secure fossil fuels for Ireland (behind peat, which is locally sourced).
Energy availability and intermittency	▪ Coal has high supply availability with coal power plants having a capacity factor of approximately 85 per cent. Coal is easily stored and does not suffer from intermittency problems.

Sustainability

Fuel longevity	▪ Combining the predicted levels of reserves with predicted rate of production suggests that the longevity of coal is declining. In 2010, approximately 129 years will remain, by 2020 this may be reduced to 104 years, and by 2030 just 89 years of coal may remain. ▪ Coal, however is the one of the fossil fuels that is expected to last for the longest – more than oil (excluding unconventional) and gas.
Environmental impact	▪ Coal is one of the most polluting fuels and is associated with a range of environmental impacts – both along the supply chain and locally (at the point of use). Coal has the second highest externality cost at €90/MWh (only behind unconventional oil) – a position which is likely to remain in the longer-term.

Climate change

Carbon content	▪ Coal is one of the fuels with the highest carbon content at 101 tCO_2/TJ (on a par with peat and bio-residues).
Lifecycle carbon footprint	▪ Coal has one of the largest carbon footprints. Brown coal is significantly more carbon intensive than black coal. ▪ Advanced coal technology (already available, but not mainstream yet) offers markedly lower carbon emissions per unit of energy output. 20-30 per cent emission reductions are plausible by 2020 purely on the basis of coal conversion efficiency. Carbon capture and storage (CCS) may offer a breakthrough solution for coal, cutting carbon emissions typically by up to 85 per cent (but theoretically up to 100 per cent). When this is factored in, coal becomes the cleanest fossil fuel (NB: natural gas CCS was not explored in this study).

Supply and infrastructure vulnerability	▪ Some climate induced risk is plausible for coal in terms of transport.
Availability change	▪ Coal is not subject to climate change.

1.1: Coal: the basics

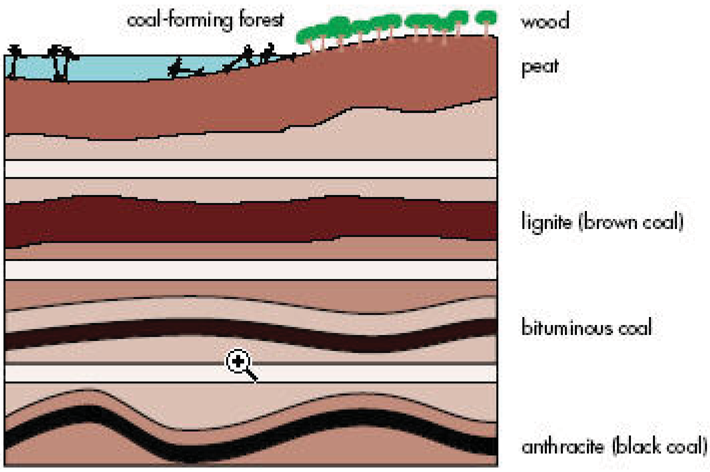
Coal is a fossil fuel. It is a combustible, sedimentary, organic rock, which is composed mainly of carbon, hydrogen and oxygen. It is formed from vegetation, which has been consolidated between other rock strata and altered by the combined effects of pressure and heat over millions of years to form coal seams. Specifically, coal formation began during the Carboniferous Period – known as the first coal age – which spanned 360 million to 290 million years ago. There are several types and qualities of coal, dependent on the temperature, pressure and the length of time in formation. The degree of change undergone by a coal has an important bearing on its physical and chemical properties and is referred to as the 'rank' of the coal, see Table 1.1 for descriptions.

Table 1.1: Rank of Coal

Rank	Name	Description
High	**Anthracite**	Anthracite is coal with the highest carbon content, between 86 per cent and 98 per cent, and a heat value of nearly 15,000 BTUs-per-pound. The principal use of anthracite today is for a domestic fuel in either hand-fired stoves or automatic stoker furnaces. It delivers high energy per its weight and burns cleanly with little soot. Its high value makes it prohibitively expensive for power plant use. Per cent of world reserves[4]: 1 per cent
	Bituminous	Bituminous coal has a carbon content ranging from 44 per cent to 86 per cent carbon and a heat value of 10,500 to 15,500 BTUs-per-pound. Bituminous coal is used primarily to generate electricity and make coke for the steel industry. Per cent of world reserves: 52 per cent
	Sub-bituminous	Ranking below bituminous is sub-bituminous coal with 35 per cent to 45 per cent carbon content and a heat value between 8,300 and 13,000 BTUs-per-pound. It is primarily used as a fuel for steam-electric power generation and in the cement industry. Per cent of world reserves: 30 per cent
Low	**Lignite**	Lignite is a geologically young coal which has the lowest carbon content, 25 per cent to 35 per cent, and a heat value ranging between 4,000 and 8,300 BTUs-per-pound. Sometimes called brown coal, it is mainly used for electric power generation. Per cent of world reserves: 17 per cent

4 World Coal Institute ,2005

Figure 1.1: Formation and types of coal



Source : www.teachers.ash.org.au

Using coal for energy

Steam coal, also known as thermal coal, is used in power stations to generate electricity. The earliest conventional coal-fired power stations used lump coal which was burnt on a grate in boilers to raise steam. More recently, the coal is first milled to a fine powder, which increases the surface area and allows it to burn more quickly. In these pulverised coal combustion systems, the powdered coal is blown into the combustion chamber of a boiler where it is burnt at high temperature. The resulting heat is used to produce steam which drives a turbine that generates electricity.

Coal currently supplies 39 per cent of the world's electricity. In many countries the proportion of electricity supply from coal is much greater. The availability of low-cost supplies of coal in both developed and developing countries has been vital to achieving high rates of electrification. For instance, in China, 700 million people have been connected to the electricity system since the early 1990s with around 77 per cent of the electricity produced in coal-fired power stations.

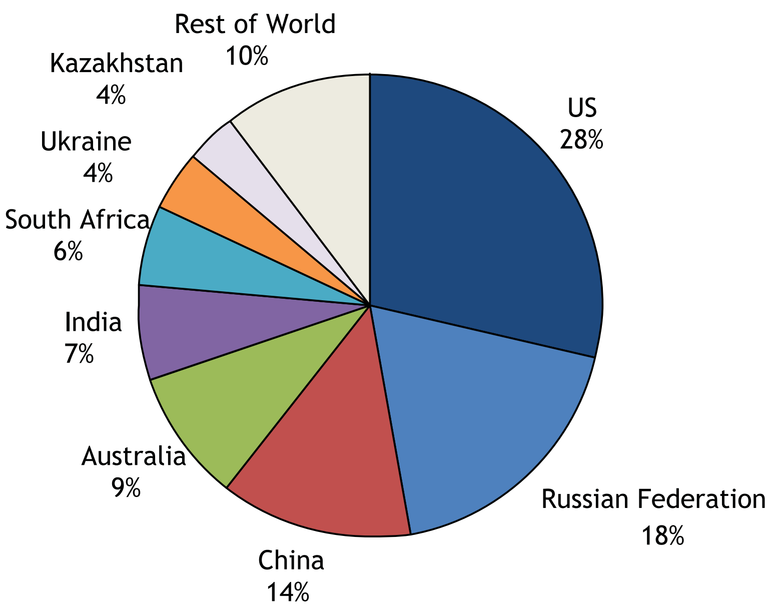
1.2: Coal as a commodity

1.2.1 Global reserves

Proven world coal reserves were estimated at just under 850 billion tonnes at the end of 2007.[5] Proven reserves are defined as 'those quantities that geological and engineering information indicates with reasonable clarity can be recovered in the future from known deposits under existing economic and operating conditions'[6]. The 2007 global reserves-to-production ratio[7] suggests that coal production may continue for a further 133 years. A similar estimate was reported in the US EIA's International Energy Outlook 2008 where global reserves were estimated at 930 billion short tonnes as of January 2006. The reserves-to-production ratio was therefore 143 years. The IPCC (2006) reported that proven conventional coal reserves in 2005 were 22,000 exajoules (EJ) with another 11,000 EJ of unproven reserves.

Although over seventy countries have proven reserves, approximately 76 per cent of reserves are located in just five countries: USA (28.6 per cent), Russia (18.5 per cent), China (13.5 per cent), Australia (9 per cent) and India (6.7 per cent). At current rates of production, China is estimated to deplete its known coal reserves within 50 years whereas Russia could have 500 years of coal production remaining. Figure 1.2 illustrates the distribution of proven coal reserves on a global basis.

Figure 1.2: Proportion of global proven coal reserves, by country (2007)



Source: World Energy Council (2007)

5 World Energy Council, 2007

6 BP,2008, *Statistical Review of World Energy*

7 The reserves-to-production ratio is calculated by the total reserves at the end of 2007 divided by the production in that year. Therefore the ratio estimates the length of time the remaining reserves would last if production were to continue at the current rate

In 2007, China (41 per cent) and the USA (18 per cent) accounted for just under two thirds of the total global coal consumption of 3,178 Mtoe[8]. Ireland played a nominal role, consuming under 0.05 per cent of the global total. This situation suggests Ireland faces major competition for coal supplies if or when stocks begin to dwindle.

The US EIA's International Energy Outlook 2008 predicts that global coal consumption will rise by 65 per cent between 2005 and 2030, from 122.5 quadrillion Btu to 202.2 quadrillion Btu. China and India are expected to account for 79 per cent of the projected growth. Similarly, the 2007 update of the EU European Energy and Transport Trends to 2030 forecasts global coal consumption to increase from 2,408 Mtoe in 2001 to 4,241 in 2030. This represents a growth of 76 per cent over the three decades, see Table 1.2.

Table 1.2: Global coal consumption forecast to 2030

	2001	2010	2020	2030
EC DG TREN (Mtoe)	2,408	3,422	3,900	4,241
US EIA (Quadrillion Btu)	-	140.2	172.1	202.7

Source: As stated in table

Table 1.3 below summarises the level of coal availability expressed as the reserves-to-production ratio (longevity) over the three timescales - 2010, 2020 and 2030.

Table 1.3: Coal reserves to production ratio

	BP	WEC[9]	WCI[10]	US EIA	Average
Years remaining	133	150	147	143	143

Source: As stated in table

There is no readily available information on future estimates for global reserves. The actual figures are highly dependent on estimated future production forecasts. Therefore, for the purposes of this study, we have combined the current projections for coal production with the current level of global reserves (see Table 1.4 below).

8 BP,2008, *Statistical Review of World Energy*

9 World Energy Council

10 World Coal Institute

Table 1.4: Forecast coal reserves 2010, 2020, 2030

	Production (mt)	Reserves (mt)	Year remaining
2007	5,900	847,000	143
2010	6,440	830,000	129
2020	7,340	765,000	104
2030	7,980	692,000	87

Source: EC DG TREN, US EIA, BP, WEC, WCI.

In summary in terms of fuel longevity, Table 1.5 outlines the projected coal longevity in 2010, 2020 and 2030 for brown and black coal.

Table 1.5: Projected coal longevity in 2010, 2020 and 2030 in years remaining

	2010	2020	2030
Brown coal - Average value	142	104	87
Black coal - Average value	129	104	87

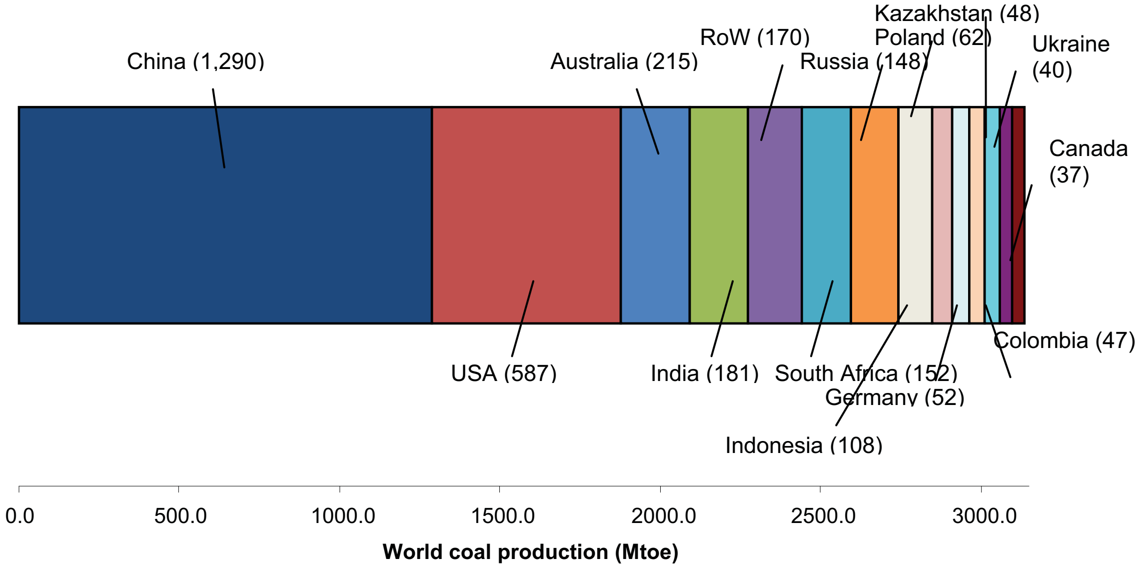
Source: various - as described in the paragraphs above

1.2.2 Global production and trade

Globally, the supply of coal is particularly diverse as coal is commercially mined in over 50 countries, see Figure 1.3. In 2007, 3,136 Mtoe[11] of coal were produced. China led the way with 1,290 Mtoe, which equated to 41 per cent of the total world production. Following China were the USA with 587 Mtoe, Australia - 215 Mtoe, India - 181 Mtoe and South Africa - 152 Mtoe (BP 2008). It has to be noted, however, that the majority of China's coal production is for domestic supplies.

11 Million tonnes of oil equivalent

Figure 1.3: World coal production, 2007

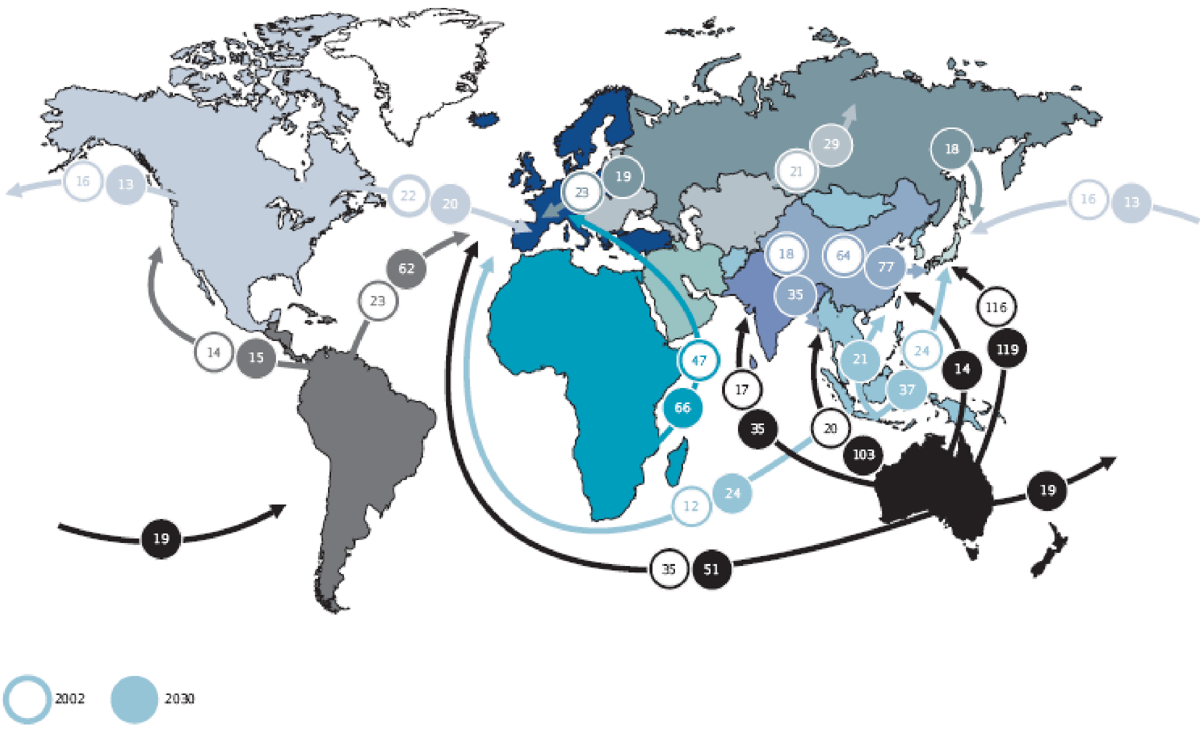


Source: Adapted from BP (2008)

In terms of coal exports, only black/hard coal is traded internationally and the total volume in 2007 was 917 million tonnes of coal (Mt), or just 16.5 per cent of the total hard coal produced[12]. The largest coal exporting nation is Australia, which exported 244 (Mt) in 2007 and other significant exporters include Indonesia (202 Mt), Russia (100 Mt), Colombia (67Mt) and South Africa (67Mt). Figure 1.4 below shows the recent (2002) and projected (2030) coal trade flows produced by the World Coal Institute (2005).

12 IEA, 2008b, *Key World Energy Statistics 2008*

Figure 1.4: Major Inter-Regional Coal Trade Flows, 2002-2030, in million tonnes of coal (Mt)



Source: World Coal Institute (2005)

The majority of Ireland's coal imports currently come from two countries: Colombia (42 per cent) and Indonesia (30 per cent)[13]. As is evident from Table 1.6 below, 97 per cent of coal imports are bituminous type coal (black coal).

13 SEI,2007b, *Security of Supply in Ireland*

Table 1.6: Source of Ireland's coal imports

000' tonnes	Anthracite	Bituminous	Lignite	Manuf Ovolds	Total	% of Total
Columbia	-	1,090	-	-	1,090	41.9
Indonesia	-	779	-	-	779	29.9
S Africa	10	365	-	-	375	14.4
Unknown	33	198	-	-	231	8.9
Poland	-	62	-	-	62	2.4
Holland	-	36	-	-	36	1.4
Germany	-	-	13	2	15	0.6
Ukraine	8	-	-	-	8	0.3
UK	5	-	-	-	5	0.2
Total	56	2,531	13	2	2,602	100

Source: SEI (2007b) Security of Supply in Ireland

Table 1.7 below suggests that the current Irish coal import mix is slightly weighted towards riskier countries. The OECD suggests that the countries which Ireland relies most upon, i.e. Colombia and Indonesia, have relatively high country credit risk classifications. Similarly, the World Bank's Ease of Doing Business Index suggests that Indonesia in particular has weak business regulations, which reduce the simplicity and ease of doing business within the country.

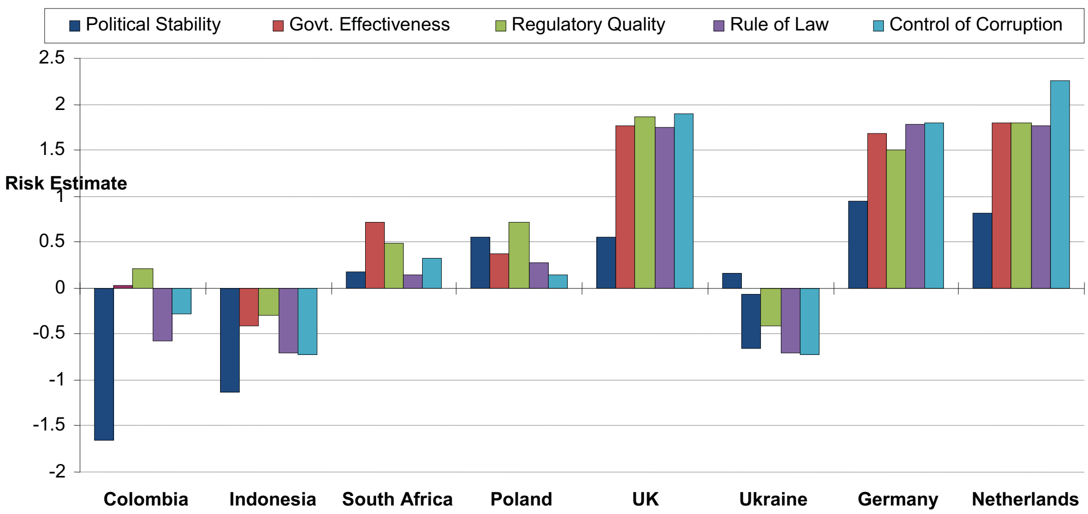
Table 1.7: Country Risk and ease of doing business indicators

	OECD Country Risk Classification 2008 (score from 0-7, higher figure equals higher risk)	World Bank Ease of Doing Business index 2008 (rank of 178 countries)
Colombia	4	53
Indonesia	5	123
South Africa	3	35
Poland	2	76
Netherlands	0	26
Germany	0	25
Ukraine	5	139
United Kingdom	0	6

Source: OECD and World Bank. Note: The OECD figure measures the country credit risk, i.e. the likelihood that a country will service its external debt. The World Bank index measures regulations directly affecting businesses and protections of property rights

Figure 1.5 below illustrates current socio-political risk as measured by the World Bank's World Governance Indicators. A similar picture is evident, with Colombia and Indonesia performing particularly poorly in comparison to other sources of Irish coal imports.

Figure 1.5: World Bank's World Governance Indicators 2008



Source: World Bank. Note: The risk estimates are normally distributed with a mean of zero. Almost all values lie between -2.5 and 2.5.

There is no readily available information on future estimates for country risks and political stability. Therefore, for the purposes of this study, the current World Bank and OECD indicators are used. The methodology, however, takes into account the possible future mix of countries that will comprise the main coal exporters (on the basis of proven reserves and current willingness to export).

1.2.3 Coal Prices and Markets

Coal Markets

Coal is traded all over the world, with coal shipped huge distances by sea to reach markets. Over the last twenty years, seaborne trade in steam coal has increased on average by about 8 per cent each year, while seaborne coking coal trade has increased by 2 per cent a year[14]. Overall, international trade in coal reached 815 Mt in 2006; while this is a significant amount of coal it suggests that over 80 per cent of coal is consumed in the country of origin.

Transportation costs account for a large share of the total delivered price of coal, therefore international trade in steam coal is effectively divided into two regional markets – the Atlantic and the Pacific. The Atlantic market is made up of importing countries in Western Europe, notably the UK, Germany and Spain. The Pacific market consists of developing and OECD Asian importers, notably Japan, Korea and Chinese Taipei. The Pacific market currently accounts for about 60 per cent of world steam coal trade. Markets tend to overlap when coal prices are high and supplies plentiful.

Coal price

There is no single global price for coal. This is a reflection of both the number of varieties of coal, the qualities of coal, and the number of uses for coal. Coal is also physically traded as well as financially traded (i.e. in the form of options and future). The ‘Big Four’ players in the physical market are Xstrata/Glencore, BHP Biliton, Anglo American, and Rio Tinto. Coal is chiefly sold under long-term contracts that ‘fix’ the price of coal over the term of the contract, usually with an escalator based on inflation. Also, there are well-established world spot markets for coal that are the source for most quoted spot prices.

The chart in Figure 1.6 below illustrates two recent price trends for European coal. One set of prices is taken from the BP Statistical Review of World Energy 2008[15]and shows the ‘Northwest European Marker Price’[16] and the other is supplied by the United States Energy Information Administration (US EIA) and shows the Irish ‘Steam Coal Prices for Electricity Generation’. Both sets of prices began in 1999 at around US$30 per metric tonne (t) and climbed to over US$80/t by 2007.

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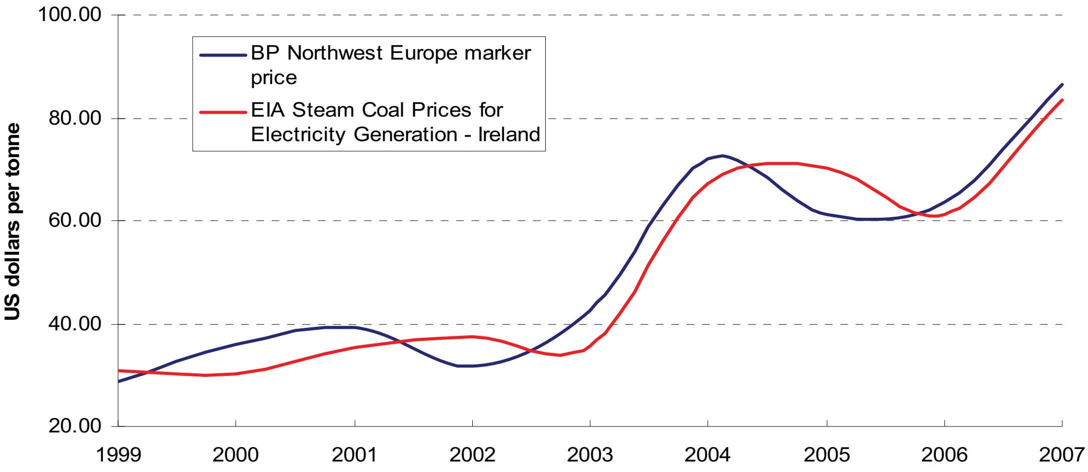
14 World Coal Institute, 2005, *The Coal Resource - A Comprehensive Overview of Coal*

15 BP,2008, *Statistical Review of World Energy*

16 Sourced originally from the McCloskey Coal Information Service

Figure 1.6: Recent coal prices per metric tonne (nominal)

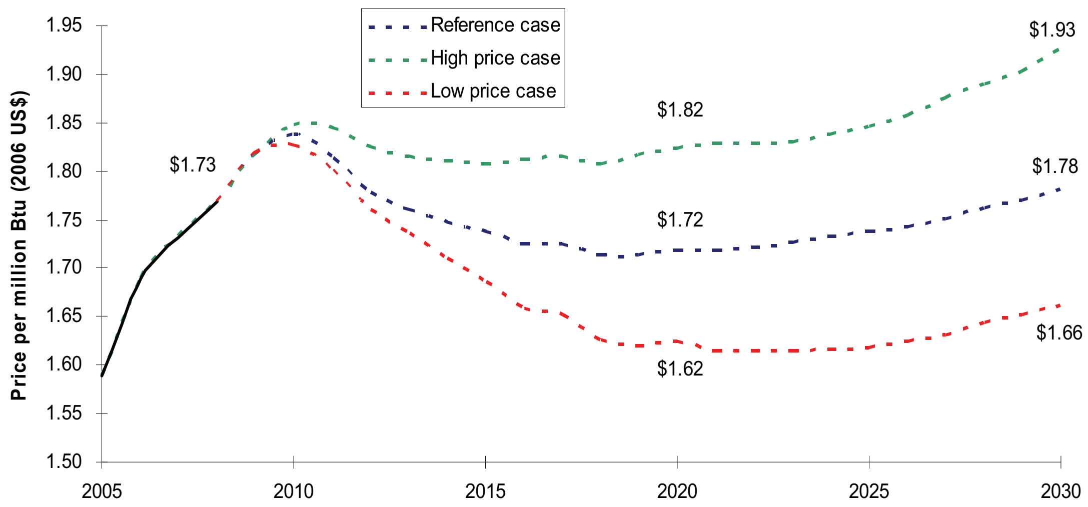


Source: BP, Statistical Review of World Energy (2008) and US Energy Information Administration, International Coal Prices

US EIA's 2008 International Energy Outlook notes that a number of supply shocks have caused the recent spike in the price of coal. These include power shortages in South African coal mines, rail car shortages in Russia, flooding in Australian coal mines and heavy snow in China. All of these contributed to tighter coal markets resulting in higher prices.

The US EIA National Energy Modelling System presents projections and analysis of US coal prices to 2030. The 'reference case' forecast assumes that current policies affecting the energy sector remain unchanged throughout the projection period. The reference case provides a clear basis against which alternative cases and policies can be compared. A high-price scenario and a low price scenario are presented along side the reference case, see Figure 1.7 below. The values in Figure 1.7 are provided in 2006 US$/MBtu, which equate to prices in US$/t as follows – US$30.80/t (2010), US$29.10/t- US$32.60/t (2020) and US$29.60/t- US$35.10/t (2030).

Figure 1.7: US Real price forecasts for delivered coal for electric power



Source: SQW using date from US EIA 2008

World Bank commodity price data (known as the 'Pink Sheets') include forecasts for future prices. Tracked within this data series is the annual average price of Australian Coal[17], the real price of which was US$57/t in 2007 and US$101/t in 2008 (Jan-Aug only). Current World Bank forecasts suggest the current price spike will fall to US$79/t in 2010 and down to US$54/t in 2015. By 2020, World Bank expects the price to be US$56/t.

The 2007 update of the EU European Energy and Transport Trends to 2030 forecasts the price of coal to rise considerably more slowly than other fossil fuels such as oil and gas. This is explained by the large resources of coal that are typically found in more favourable geopolitical conditions. It is evident from Table 1.8 below that the competitiveness of coal vis-à-vis gas is expected to increase steadily: the gas to coal price ratio increases from 2.3 in 2005 to 3.2 in 2030. This could be an important factor in future investment choices for power generation. The values in Table 1.8 are provided in 2005 US$/boe[18], which corresponds to coal prices in US$/t as follows[19] – US$68.50/t (2010), US$73.50/t (2020) and US$74.50/t (2030).

17 Coal (Australian), thermal, f.o.b. piers, Newcastle/Port Kembla, 6,300 kcal/kg (11,340 Btu/lb), less than 0.8 per cent, sulphur 13 per cent ash

18 Barrels of oil equivalent

19 1 barrel oil equivalent = approximately 0.20 metric tonnes of hard coal

Table 1.8: EU forecast fossil fuel prices to 2030

US$(2005)/boe	2005	2010	2015	2020	2025	2030
Oil	54.5	54.5	57.9	61.1	62.3	62.8
Gas	34.6	41.5	43.4	46	47.2	47.6
Coal	14.8	13.7	14.3	14.7	14.8	14.9

Source: EC (2007b) European Energy and Transport Trends to 2030. Note: Assumed dollar exchange value equal to 1.25 $/€

The International Energy Agency's World Energy Outlook for 2007 expects the real price of coal (using 2006 US$) to fall from US$63 per tonne in 2006 to US$56/t in 2010. The trend is then a steady price rise to US$57/t in 2015 and US$61/t in 2030. Table 1.9 below summarises the range of projected coal prices in 2010, 2020 and 2030 from a range of reference sources, as discussed above.

Table 1.9: Projected coal prices in 2010, 2020 and 2030 in US$ per metric tonne

Source	2010	2020	2030
IEA	56.07	-	61.17
World Bank	78.90	56.20	-
US EIA (average delivered coal price, reference case)	35.26	31.59	32.38
BERR (central scenario)	73.00	65.00	63.49
European Commission	68.50	73.50	74.50
Average value	62.35	56.57	57.88

Source: As indicated in Table 1.8

1.2.4 Weighted import dependence

Coal in Ireland's energy mix

Coal accounted for just over 9 per cent of Ireland's total primary energy requirement (TPER) in 2007 with 1,508[20] kilotonnes of oil equivalent (ktoe). Black coal accounted for 99.5 per cent of this, whilst just 7 ktoe of brown coal was used towards Ireland's TPER.

Coal was the third largest TPER input, behind oil (56 per cent) and gas (27 per cent). Between 1990 and 2007, total primary energy requirement in Ireland increased by 70 per cent, from 9,503 ktoe to 16,131 ktoe; however, coal's share of primary energy input decreased from 22 per cent in 1990 to 9 per cent in 2007. Around 75 per cent of the coal consumed (1,124 ktoe) was for electricity generation with the remainder being for domestic and industrial heat.

In 2006, coal accounted for 24 per cent of the electricity-generating fuel mix, the second largest proportion behind natural gas (46 per cent). Since 1990, coal's share of the electricity generating fuel mix has fallen from 40 per cent.

Following the decision to prolong the life of the coal fired Moneypoint power station, the use of coal in electricity generation will remain in the foreseeable future, (Moneypoint can continue to operate on coal until approximately 2020, by which time the station will be 35 years old). The 2007 IEA Irish Energy Review[21] suggests that the Irish Government should begin to consider the impact of a potential replacement of the current Moneypoint station by a clean coal station with full carbon capture and storage (CCS) should this become an economical alternative.

The Government recognised this potential opportunity in the energy policy framework document [22] and are currently gathering information to assist in developing CCS in Ireland (for example, in September 2008 Sustainable Energy Ireland (SEI), Ireland's national energy agency, released an assessment of the potential for geological storage of CO_2 for the Island of Ireland [23].

The European Commission's baseline energy forecast for Ireland[24] shows a net increase of imports and consumption of coal up to 2030, when it will amount to 2,148 ktoe and its share of the TPER is forecast to increase to nearly 14 per cent.

At present Ireland does not have any indigenous coal production and therefore all coal is imported - 1,508 ktoe of coal imports in 2007, accounting for approximately 9 per cent of total energy imports. In the future, given the lack of remaining domestic coal reserves, all supplies will continue to be from imports. Table 1.10 below summarises the sub-indicators that comprise the weighted import dependence indicator for coal in Ireland over the three timescales - 2010, 2020 and 2030.

20 All references to Ireland's 2007 TPER are taken from the SEI 2007 provisional energy balance found at: http://www.sei.ie/index.asp?locID=75&docID=-1 [Accessed 28 Sept 2008]

21 IEA,2007, *Energy Policies of IEA countries*, Ireland 2007 review

22 Department of Communications, Marine and Natural Resources (DCMNR), 2007, *Delivering A Sustainable Energy Future For Ireland 2007-2012*

23 SEI,2008c, *Assessment of the potential for geological storage of CO2 for the Island of Ireland*

24 EC DG TREN 2007

Table 1.10: Projected share of fuel mix and import dependence for coal in 2010, 2020 and 2030 in per cent

Sub-indicators	2010	2020	2030
Share of the fuel mix (TPER)	11 (SEI) 15 (PRIMES)	10 (SEI) 17.6 (PRIMES)	8 (SEI projected trend) 13.7 (PRIMES)
Import dependence	100	100	100

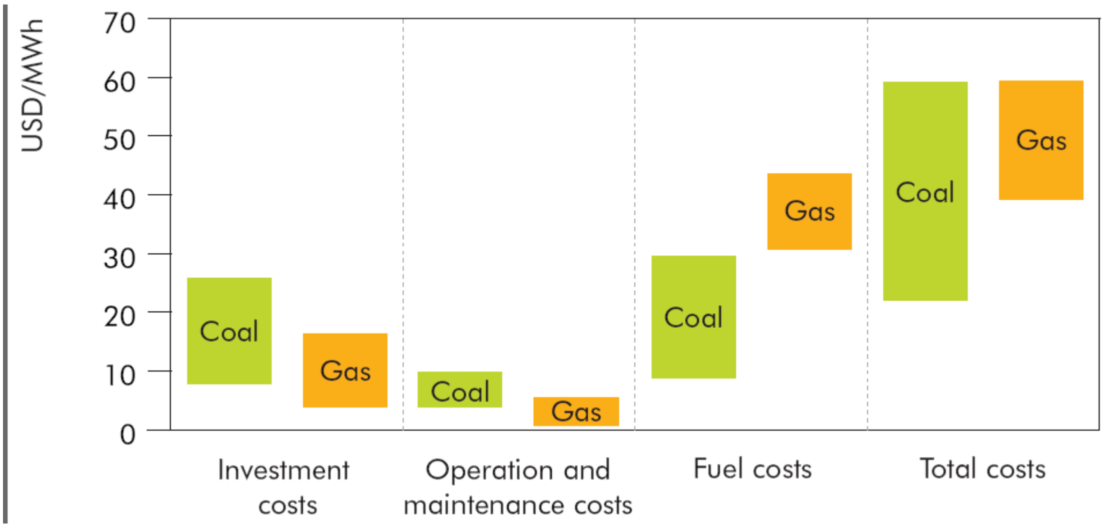
Source: as indicated in the table

1.3: Coal in the energy system

1.3.1 Delivered energy cost

The IEA suggests that the current cost of delivered energy from coal-fired plants, including capital investment, operation and maintenance (O&M) and fuel costs, ranges between US$25 and US$60 per megawatt-hour (MWh) of electricity (see Figure 1.8). This largely depends on the type and age of conversion technology used and the median value is around US$40/MWh (€32/MWh).

Figure 1.8: Delivered energy costs from coal and gas-fired plant



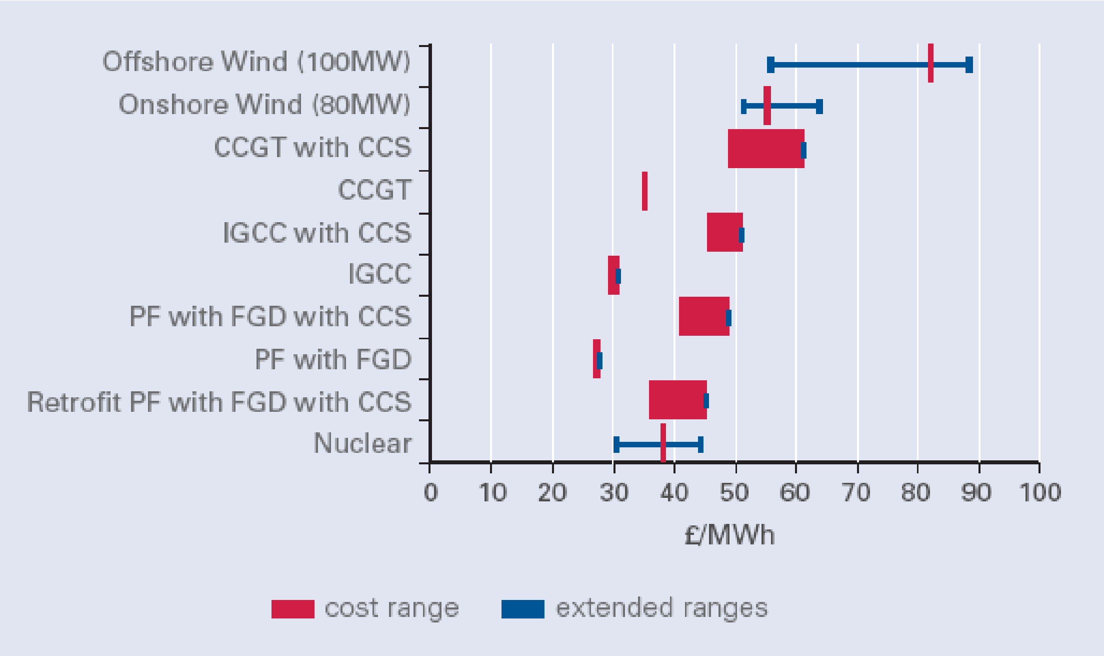
Source: IEA 2008a[25]

The UK's Department for Business Enterprise and Regulatory Reform (BERR,currently BIS), undertook modelling of the relative electricity generating costs of different technologies as part of the 2006 Energy Review. The modelling is based on levelised costs and provides estimates of the relative cost of electricity generation technologies under different scenarios and assumptions. The scenarios considered in the modelling include a base case, varying assumptions for gas and carbon prices, and a full range of sensitivities including discount rate, capital cost, O&M costs, fuel prices, carbon prices, and load factors.

Figure 1.9 below shows the results of the base case assuming central gas prices and no carbon price. The cost of electricity at a pulverised fuel (coal) power plant with flue gas desulphurisation was estimated to be in the region of £27/MWh (€34/MWh) (BERR 2006).

25 IEA, 2008a, *Energy Technology Perspectives Scenarios and Strategies to 2050*

Figure 1.9: Electricity generating costs of different technologies



Source: BERR (2006) Energy Review 'The Energy Challenge'. Note: CCGT - combined cycle gas turbine, CCS - carbon capture and storage, IGCC - integrated gasification combined cycle, PF - pulverised fuel (coal), FGD - flue gas desulphurisation.

The UK Energy Research Centre (UKERC) undertook a review of the literature on electricity generation levelised unit cost estimates. In total 145 documents were reviewed so that average cost estimates could be produced. As is evident from Table 1.11 below, the review found coal to be marginally more expensive than gas and nuclear.

Table 1.11: Electricity generation levelised unit cost estimates, £/MWh, 2007

	Coal	Gas	Nuclear	Wind	Wind (offshore)
Mean	**32.9**	31.2	32.2	39.3	48.0
Median	**31.9**	30.5	31.3	35.9	47.9
Inter-quartile range	**13.1**	9.5	16.5	24.2	33.6
Standard deviation	**9.7**	8.9	10.5	16.6	20.0

Source: UKERC (2006, updated May 2007), A Review of Electricity Unit Cost Estimates

Other cost estimates have been produced by the Stern Report (2006) and the Royal Academy of Engineering study undertaken by PB Power (2005). Both of these estimated the cost of electricity from coal to be approximately £25/MWh (€30/MWh).

1.3.2 Coal – Conversion Technologies

Coal-fired power generation technologies

Black (hard) coal-fired plants achieved average efficiencies globally of 35 per cent between the early nineties to 2005 globally; the best available technology (BAT) can achieve 47 per cent efficiency[26] .The main coal-fired plant in Ireland, Moneypoint, has an efficiency of 35 per cent[27].

Table 1.12 below summarises the main current and likely future technologies for converting coal into electricity in terms of their efficiency, stage of development and commercialisation, cost and specific circumstances around their future deployment.

Table 1.12: Summary of coal conversion technologies

Sub-critical pulverised coal

Pulverised coal combustion (PCC) plants account for about 97 per cent of global coal-fired capacity, and the majority of these are of a conventional subcritical design, which achieves typical thermodynamic efficiencies of about 30 to 35 per cent. Larger plants can achieve slightly higher efficiencies of 35 -36 per cent. New subcritical units with conventional environmental controls operate closer to 39 per cent efficiency.[28]

PCC subcritical power plants operate with steam pressure of around 180 bar and temperatures at 5,400 °C. The combustor unit can reach a capacity of up to 1,000 MW.

Super-critical pulverised coal

Supercritical steam-cycle plants, with steam pressure of around 240-260 bar and temperatures of around 5,700°C are the current commercialised BAT for coal. Their operational efficiency typically ranges between 42-45 per cent. It is expected that efficiency can be increased to just under 50 per cent [29].

Supercritical technology is already used in a number of countries. In 2006, China installed 18 GW of supercritical units.

Ultra-super-critical pulverised coal

Ultra-supercritical plants are supercritical pressure units which operate at temperatures of about 5,800° C and above. They can achieve efficiencies of up to 50-55 per cent.

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26 IEA,2008a, *Energy Technology Perspectives Scenarios and Strategies to 2050*

27 IPCC Working Group III, 2007, *Fourth Assessment Report. Chapter: Energy supply*

28 IEA, 2008a, *Energy Technology Perspectives Scenarios and Strategies to 2050*

29 Siemens, 2005, *Balancing economics and environmental friendliness - the challenge for supercritical coal-fired power plants with highest steam parameters in the future*

Although ultra-supercritical plants are still in the early stages of research, design and deployment, there is already operational capacity in Germany, Japan and Denmark. Units operating at 7,000°C and higher are still at an R&D stage.

Integrated gasification combined cycle (IGCC)

IGCC technologies turn coal (and other carbonaceous feedstocks) into synthetic gas and remove the impurities (of coal) before combustion. This process reduces the emissions of sulphur, nitrogen oxides, and mercury, as well as improving the efficiency compared to standard pulverised coal. IGCC systems are among the cleanest and most efficient of the coal technologies.

According to IEA there are 17 IGCC plants currently in operation, of which five are using coal alone. They typically achieve efficiencies of around 40-43 per cent. In the next ten years, the IEA expects IGCC to become both more widespread and achieve higher efficiencies of over 50 per cent. IGCC technology systems should be developed to a full commercial level by 2030.[30]

Oxy-fuel combustion

Oxygen-fired pulverised coal combustion (Oxy-Fuel), offers a low risk step development of existing PCC power generation technology to enable CO_2 capture and storage. Oxygen combustion combined with flue gas recycle increases the CO_2 concentration of the off-gases from around 15 per cent to a theoretical 95 per cent. Oxy-combustion is likely to give increased fuel flexibility.

The full-scale application of oxy-fuel technology is still under development. However, laboratory and theoretical work has provided an initial understanding of design parameters and operational considerations. In addition there have been a number of investigations using pilot-scale facilities in the US, Europe, Japan, and Canada.[31]

The future cost of delivered energy will rely heavily upon the future power generation technologies that are developed and deployed. The capital cost of different coal conversion technologies is reported as a wide range. The IEA[32] suggests a relatively equal capital cost per kW of installed capacity across all technologies, both conventional and advanced – ranging between US$1,500-US$2,000/kW (not including CCS capability). This estimate is supported by the former UK Department of Trade and Industry (DTI) (currently BIS) in its MARCAL model[33].

30 IEA, 2008a, *Energy Technology Perspectives Scenarios and Strategies to 2050*

31 Sourced from http://www.ccsd.biz/factsheets/oxyfuel.cfm Cooperative Research Centre for Coal in Sustainable Development-Oxy Fuel Combustion

32 IEA, 2007a, *World Energy Outlook 2007*

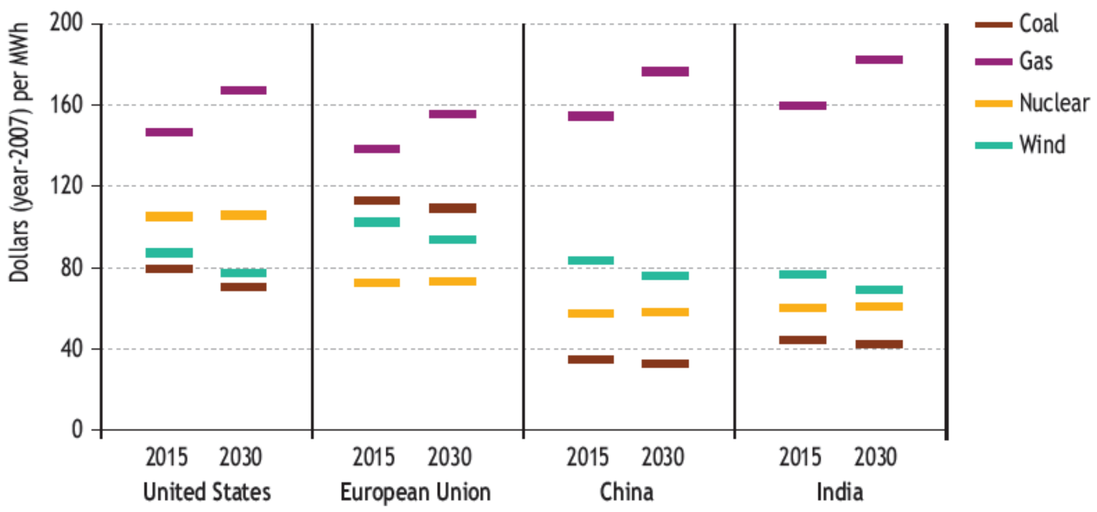
33 Department for Trade and Industry (DTI), 2005, *The UK MARKAL model*. Originally developed by the IEA and used in over 30 countries. Updated for the UK's Energy White Papar 2007 by UKERC (www.ukerc.ac.uk). Further updates and upgrades made in 2008 and 2009

Carbon price and Carbon capture and storage (CCS) options

Carbon emission reductions are now an intrinsic element of commercial energy generation and delivery in Europe through a number of statutory regulations and mechanisms. Most notably at the moment, the EU Emissions Trading Scheme (ETS) sets emissions caps on most larger generators (power and thermal) by way of allocating emissions allowances (EUAs)[34]. Over time, the amount of allowances is being decreased thus lowering the cap. EUAs are traded on the market and their price has fluctuated in the range of €15-€20. Whilst currently the EU ETS has a marginal cost impact on power generators (due to the large amount of allocated allowances), it will be increasingly a factor in the cost competitiveness of different fossil fuel-fired plants.

The IEA estimates that at €20/tCO_2, power generation from coal will be around €90/MWh over the period to 2030 – taking into account the higher generation efficiencies from advanced technologies (see Figure 1.10 below).

Figure 1.10: Cost of power generation from coal over the period to 2030



Source: IEA 2008c[35]

Carbon capture and storage (CCS) is an emerging technology that is most pertinent to coal (as well as natural gas). The aims and potential of CCS is to remove and store typically up to 85 per cent of carbon emissions (but theoretically up to 100 per cent), thus making coal-fired plants significantly cleaner. Large-scale CCS is still considered to be at an early R&D and demonstration stage despite four projects already being in operation in 2007, storing about 1 million tonnes of CO_2 each (Sleipne and Snohvit in Norway; Weyburn in Canada; Salah in Algeria).

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34 1 EUA = 1 T CO2

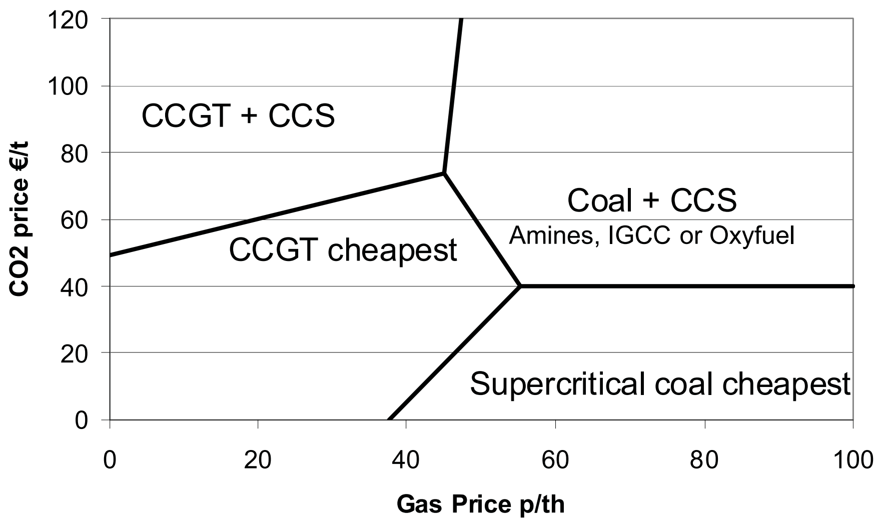
35 IEA, 2008c, *World Energy Outlook 2008*

The capital costs associated with CCS are rather high - €35-€55 per t CO_2 abated - which poses serious questions as to the economic viability of using this technology, especially in a retrofit situation (which is more expensive to install).

A recent report by McKinsey & Co (September 2008) asserts that the break-even capital and operating cost of a CCS installation is at €30-€45 per tonne of CO_2 abated in 2030 (in real terms). This is seen as an acceptable level because the market price of carbon (e.g. via an EU ETS mechanism) is expected to be at this level. Early demonstration projects, however, are much more expensive and would only be viable at a carbon price of around €60-€90/t CO_2 [36].

There are political initiatives towards making CCS mandatory for new-build power plants especially in the EU and a draft European Directive has been circulated for consultation. In the round, both at the demonstration and deployment stages of CCS it is expected that the technology will be cost neutral (life-cycle). This will be achieved through three main revenue mechanisms: 1) revenue from enhanced oil recovery, 2) revenue from carbon emissions trading and 3) public sector grants and subsidies to fill any potential funding gaps that may jeopardise the deployment of CCS[37]. Therefore, regarding total delivered energy cost from coal, future price estimates assume no cost impact from applying CCS.

Figure 1.11: Cheapest fossil-fuel plant on the basis of carbon and gas prises



Source: E.ON (2008 and earlier) Conference presentation (various events, e.g. **http://www.coal.org/pdf/ProfessorAllanJones.pdf; http://www.unece.org/energy/se/pp/clep/ahge1/27am/1.5_Bruidegom.pdf**)

NB: 2007 prices; coal delivered price of €2.5/GJ

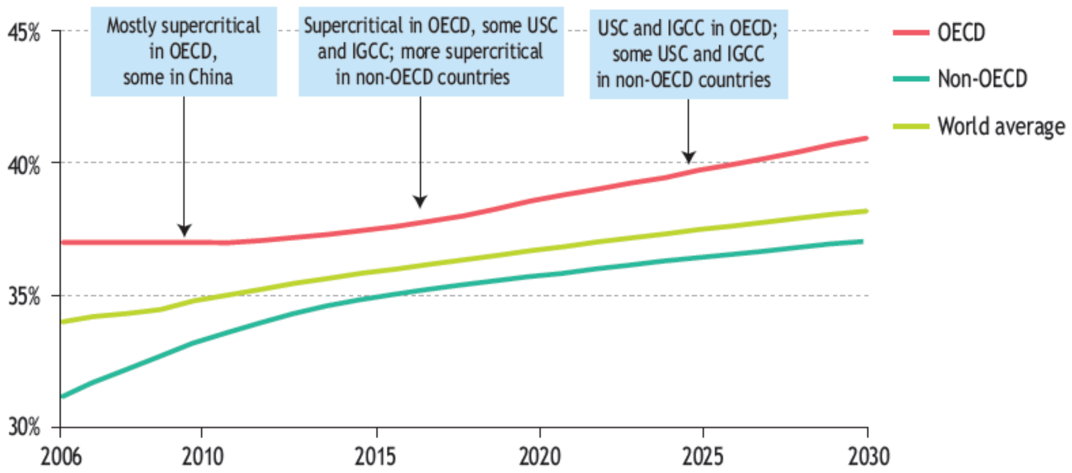
36 McKinsey & Company ,2008, *Carbon Capture and Storage: Assessing the Economics*

37 EC/ ECN, Norton Rose, GIG, ERM, 2008a, *Technical support for an enabling policy framework for carbon dioxide capture and geological storage*. Task 3: Incentivising CO2 capture and storage in the European Union

Future trends and scenarios

Future delivered energy prices from coal combustion are not readily available. To estimate the levelised price of electricity generation, the best available technology (BAT) expected to be fully commercialised (i.e. that can be considered as mainstream) was used as the benchmark. The IEA's World Energy Outlook 2008 suggests the following coal technology deployment scenario to 2030 for OECD (and non-OECD) countries (Figure 1.12).

Figure 1.12: Coal-fired generation technologies (and efficiency improvements) in the IEA's Reference scenario (2008)



Note: Average efficiency of installed coal-fired capacity. USC refers to ultrasupercritical steam conditions. IGCC refers to integrated gasification combined cycle.

Source: IEA [38]

Thus, for the high scenario (full development and uptake of advanced coal combustion technologies) the following technologies were taken as the benchmarks for each of the three time horizons:

2010 - the currently available supercritical boilers

2020 – integrated gasification combined cycle (IGCC) technology

2030 – ultra-supercritical boilers, oxy-fuel combustion and IGCC

Estimates for the levelised electricity price of different coal technologies are reported in the MIT Future of Coal report [39], as shown in Table 1.13 below, and the timescale for deployment and commercialisation are taken from the IEA World Energy Outlook 2008.

38 IEA, 2008c, *World Energy Outlook 2008*

39 Massachusetts Institute of Technology (MIT),2007, *The Future of Coal*

Table 1.13: Levelised cost of electricity from coal in US$/MWh

Technology	Subcritical	Supercritical	IGCC	Ultra-supercritical	Oxy-fuel with CCS
Timescale assumed	**Current**	2010	2020	2030	2030
Levelised cost (US$/MWh)	**48.4**	47.8	51.3	46.9	69.8

Source: MIT and IEA

Table 1.14 below summarises the range of projected delivered energy prices in 2010, 2020 and 2030 from a range of reference sources. The prices are presented in €/MWh.

Table 1.14: Projected delivered energy prices (from coal) in 2010, 2020 and 2030 in €/MWh

Source	2010*	2020	2030
IEA	32	-	-
UK BERR	34	38	61
UKERC	30	-	-
MIT	36	38.5	52.5
Royal Academy of Engineering	31	40	-
Stern (UK HM Treasury)	33	-	60
NEA40	31	-	-

Source: as shown in the first column

* these are typically the values for current prices as 2010 forecasts were not readily available

1.3.3 Policy and regulation

The most prominent regulations affecting the use of coal, and as a result its competitiveness through the price of energy from coal, stems from the European Union (EU). In January 2005 the first phase of the EU Greenhouse Gas Emission Trading Scheme (EU ETS) commenced

40 Nuclear Energy Agency

operation as the largest multi-country, multi-sector greenhouse gas emission trading scheme world-wide. Whilst it is geared up towards making absolute carbon emission reductions, the EU ETS's impact in practice will be to increase the marginal cost of fossil-fuelled power generation, as well as to create new opportunity costs in the power sector arising from the established price of carbon. In the first phase, the EU ETS coverage included:

- Energy activities - power generators, combustion installations with a rated thermal input exceeding 20MW, mineral oil refineries, coke ovens;
- production and processing of ferrous metals;
- mineral industries - cement clinker, glass and ceramic bricks; and
- pulp, paper and board activities.

Under Phase 1 of the EU ETS, large emitters of carbon dioxide were granted free allowances permitting them to emit specific levels of CO_2. If necessary, additional allowances could be purchased from others installations, traders, or the government. Similarly, if an installation receives more free allowances than it needs, it may sell them.

Since January 2008, the second trading period commenced which will last until December 2012. Phase two increased the scope of the ETS with the inclusion of credits from Joint Implementation projects. This may still be further increased through the inclusion of emissions from the aviation industry. Recent proposals have also been made for phase three, including centralizing the allocation of allowances by an EU authority,auctioning more permits rather than free allocation, and expanding the number of gases that are currently monitored.

The **Large Combustion Plants Directive** (LCPD) entered into force in November 2001, replacing an older similar directive. It applies to combustion plants with a rated thermal input of greater than 50 MW. It aims to reduce acidification, ground level ozone and particles throughout Europe by controlling emissions of SO_2, NO_X and dust from large combustion plants. These include plants in power stations, petroleum refineries, steelworks and other industrial processes running on solid, liquid or gaseous fuel.

New plants (licensed on or after 01/07/87) had to comply with emission limits fixed in the Directive by January 2008. "Existing Plant" (licensed before 01/07/87) also had to comply with emission limits set in the Directive, or operators could choose to run them at less than 20,000 hours between 2008-2015 and then nominate them as peaking plant - in which case they can run up to 2,000 hours a year. Member States could also develop a National Emission Reduction Plan (NERP) which defines a fixed annual tonnage of SO_2, NO_X and dust that could be emitted by all existing installations as of January 2008. This tonnage must not exceed the amount of emissions that would be obtained by applying the emission limits set in the Directive to each plant individually. The stringency of the LCPD is due to increase by January 2016 with stricter emissions limits being imposed. This has a particularly strong impact on coal-fired plants.

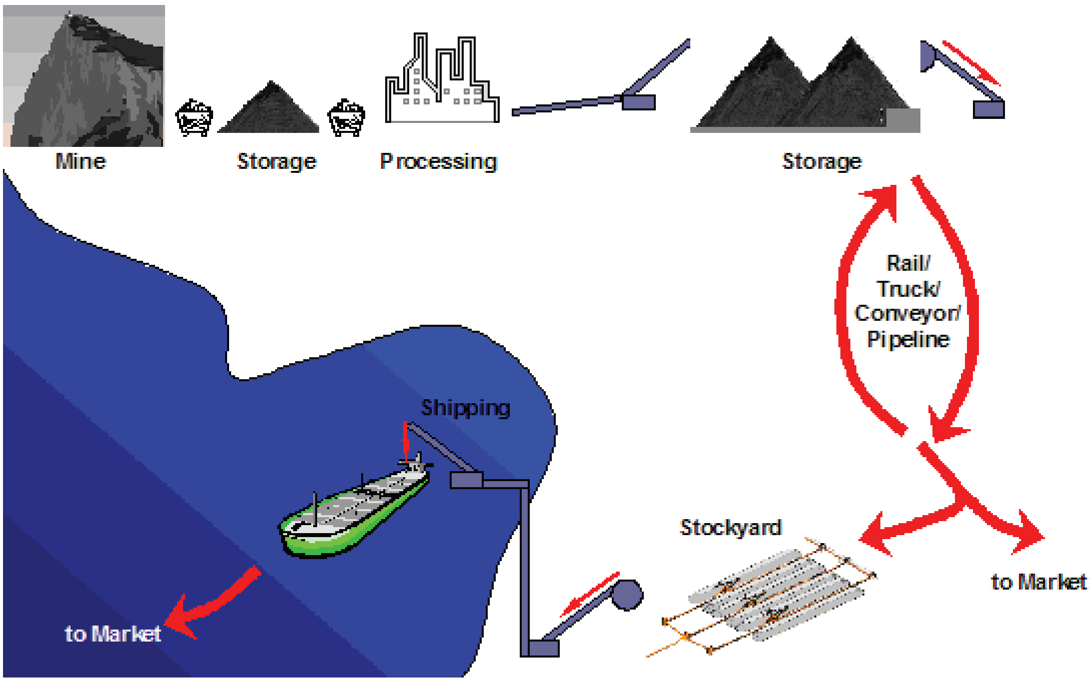
The **Integrated Pollution Prevention and Control Directive** (IPPC) imposes a requirement for industrial and agricultural activities with a high pollution potential to have a permit that can only be issued if certain environmental conditions are met, so that the companies themselves bear responsibility for preventing and reducing any pollution they may cause. Effectively the IPPC enforces minimum standards for polluting industries, including energy generation. The aim is to reduce the environmental impact of regulated processes, through encouraging the application of Best Available Techniques (BAT).

In January 2008 the European Commission proposed a draft Carbon Capture and Storage Directive. The aim of the proposal was to enable the European Union to begin capture and geological storage of carbon dioxide. This is expected to be achieved through a new regulatory/legal framework and support mechanisms for large-scale demonstration projects within the EU. It is still to be decided whether carbon capture and storage will be mandatory for the European power sector or whether market instruments will be deployed.

1.3.4 Supply chain and infrastructure resilience

The supply chain infrastructure for coal is relatively sturdy. Coal can be moved over long distances by ship and also shorter distances by rail, road, and barge. As a result of coal's ease of transportation it is often stocked at various points between leaving the mine and being delivered to the user. Coal is typically kept in a variety of storage units, with some that can hold up to 180,000 tonnes of coal. The only major concern when storing coal is reducing the likelihood of combustion. This can be done through using storage structures made of non-combustible materials, and those designed to minimize the surface area on which coal-dust can settle.

Figure 1.13: A typical coal supply chain



Source: www.sandwell.com

Ireland's shipping infrastructure is already in place for importing coal. The ports of Dublin and Shannon Foynes have dealt with coal shipments for many years. There are few risks associated with coal in comparison to other fuels. Coal is easily stored and therefore its intermittency, or fluctuation in supply, is close to zero.

There are three large coal storage units in Ireland, based at Moneypoint power plant[41]. Moneypoint holds, on average, three months stock on-site, the largest quantity being stored towards the end of the summer period/leading into the winter period.

All the coal used in Ireland is imported. Since its purchase of Coal Distributors Ltd (CDL), Bord na Móna, a private Irish company owned by the State, has become the largest importer to the residential domestic market with imports coming largely from the USA, Poland and the UK [42]. The main user of coal in Ireland is the Electricity Supply Board (ESB) at its coal-fired electricity-generating plant at Moneypoint. The ESB imports its own coal supplies from a variety of producer countries such as the USA, Australia and Colombia.

1.3.5 Market context in Ireland

Grid connection is not likely to be a particular issue, any more than for other fossil-fuel plants. Given that Ireland imports all of its coal, it will be most economic and practical to locate a new coal-fired plant along the coast, but the choice of site(s) will be critical to the competitiveness as it will affect the entire coal supply chain and respectively cost. Therefore, ESB as the incumbent operator of coal-based capacity will be in a favourable position to add new capacity and make use of its existing supply chain. Other generators will be reluctant to commit to coal.

The above considerations mainly apply to black coal, which will perform relatively well in the Irish market context, but will be impacted by the historic limitations of a single viable market player. In contrast, brown coal will perform very poorly in the Irish market context as its current use is negligible and developing a supply chain and new capacity will not be viable under the majority of potential future circumstances.

1.3.6 Market volatility

Coal is abundant world-wide and there are a large number of export countries. As a commodity, coal's market security is fairly high as no particular shocks have been recorded historically and this situation is expected to continue in the foreseeable future. Given the range of supply options available to Ireland and the country's relatively low volume of demand (compared to other countries), it is very unlikely that even if a degree of market shock occurs this will affect Ireland's supply. These considerations apply to both black and brown coal. However, as brown coal is more abundant and, due to its lower value, is transported over shorter distances (currently from Germany), its scores are higher in this regard than those for black coal.

1.3.7 Energy availability and intermittency

Coal is a storable fuel and therefore it can be available continuously without interruption (non-intermittent). Typical capacity factors for current coal-fired power plant are in the order of 85 per cent. Over time, with advancements in technology, both in the existing type

41 CER, 2008, *Ireland Security of Supply Electricity*

42 IEA, 2007b, *Energy Policies of IEA Countries* - Ireland 2007 Review

of plant and new technologies (super and ultra-super critical plan, IGCC, etc.) the capacity factor is expected to improve. Table 1.15 below summarises the energy availability and intermittency scores for coal in 2010, 2020 and 2030 expressed as a percentage.

Table 1.15: Coal energy availability and intermittency in per cent

Availability, per cent	2010	2020	2030
Brown coal	85%	85%	90%
Black coal	85%	85%	90%

Source: Based on literature review

1.3.8 Environmental impacts

The generation stage has the largest impact on the environment. Furthermore, within the generation stage, two types of impact in particular predominate. These are global warming and public health effects.

Considering only the illustrative restricted range, the global warming damage resulting from the generation stage accounts for between 31 per cent and 53 per cent of the total damage from that stage.

If we leave aside global warming, and consider separately the other types of damage, about whose magnitude we may be more certain, we find that the public health effects of atmospheric emissions from the generation stage amount to 85 per cent of the total.

Of the public health damages, which total 35 m€CU/kWh, we find that the damage caused by particulates is relatively insignificant, at 0.52 m€CU/kWh. This is because this pollutant's harmful effects are confined to the local area around the plant, which is sparsely populated. Nitrogen oxides are more important, at 13 m€CU/kWh, but the largest contribution to the total damage is sulphur dioxides, at 22 m€CU/kWh [43].

This is a direct result of the fact that the sulphur emissions of the Moneypoint plant are very high relative to similar plant elsewhere in Europe. Moneypoint is not fitted with flue gas desulphurisation equipment.

The value of total damages from the Moneypoint fuel cycle, and in particular from the generation stage, is best interpreted as resulting from a balance between the sparse population of the rural area around Moneypoint, and the high levels of sulphur dioxide emitted. These two facts tend to cancel each other and result in a figure that is neither particularly high nor particularly low by comparison with similar plant in other countries.

43 UCD Environmental Institute, 2006

1.4: Coal and Climate change

1.4.1 Carbon content of fuel

The IPCC provides a detailed account of the carbon content of all organic fuels, including fossil fuels and biomass in their Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Coal is defined as eleven categories, depending on its rank (maturity). Brown coal (lignite) has a carbon content of 101 tCO_2/TJ[44]. Black coal comprises four main categories - anthracite, coking coal, bituminous coal and sub-bituminous coal – where the carbon content is within a 94.6-98.3 tCO_2/TJ range. The carbon content of fuels is constant over time and therefore the 2010, 2020 and 2030 values are all the same.

Table 1.16 below summarises the carbon content of different categories of coal expressed in tCO_2/TJ in 2010, 2020 and 2030.

Table 1.16: Carbon content of different categories of coal used in the Tetralemma Index in 2010, 2020 and 2030 in tCO_2/TJ

Coal category	2010	2020	2030
Brown coal	101	101	101
Black coal	96	96	96

Source: IPCC 2006

1.4.2 Total carbon footprint

The principle factors determining the total, or lifecycle, greenhouse gas (GHG) emissions associated with a fuel are the conversion technology (i.e. power plant) - its type and operational efficiency - and the fuel delivery supply chain – i.e. transport and other fuel handling/refining. In terms of thermal efficiency, across the different technologies by and large, it increases with the plant load factor (although efficiency reductions can be observed towards achieving full load operation). Therefore GHG emissions depend on the mode of a plant's operation, such as peak load management, base load supply, combined heat and power supply etc.

Black coal

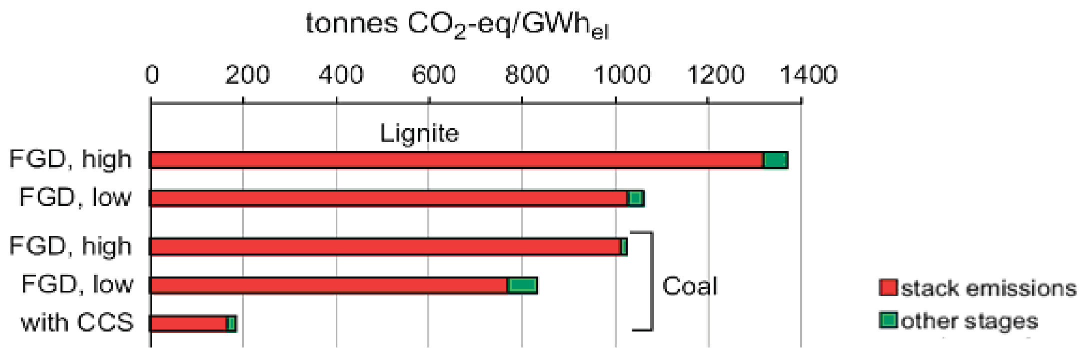
The IAEA asserts that while GHG emissions from construction, decommissioning and waste disposal are negligible, emissions relating to coal mining and coal transport can be significant[45]. Their estimate is that cumulative emissions for black coal range between 0.95 and 1.25 $kgCO_2e$/kWh. The lower end of this scale is around the actual estimate for total carbon emissions of the main coal-fired power plant in Ireland (Moneypoint) –

44 Terajoule

45 International Atomic Energy Agency (IAEA),2006, *A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies*, In Planning and Economics Studies Section

0.945 kg CO_2e/kWh[46] . The IPPC, quoting a number of sources, provides a life-cycle emissions range from just over 0.8 $kgCO_2e$/kWh to just over 1.0 $kgCO_2e$/kWh see Figure 1.14.

Figure 1.14: Life-cycle carbon emissions from brown (Lignite) and black ('Coal') power plants



Source: IPCC 2006 (quoting WEC 2004 and other sources)

Future projections from IEA show improvements in thermal efficiency so that in 2020 emissions are likely to be reduced to 0.75 kg CO_2e/kWh by 2020. If we assume that all efficiencies are implemented by 2030 and efficiencies reach 45 per cent (from current average efficiency levels of 30 per cent) for hard coal fired power plants, this would result in a decrease of carbon emissions by 33 per cent [47]. This would mean that carbon emissions could be reduced to 0.65 $kgCO_2e$/kWh by 2030. If carbon capture and storage (CCS) is deployed, lifecycle emissions from coal-fired plants can be reduced by over 80 per cent, reaching emission levels of below 0.2 $kgCO_2e$/kWh, which is a plausible scenario for 2030[48] .

In the case of Moneypoint, it is a relatively old power plant with an operational efficiency of approximately 35 per cent [49]. A gradual replacement of its subcritical coal-fired units as well as retrofitting larger scale units would bring its efficiencies to approximately 40 per cent [50]. If CCS technology is also applied, its total carbon can be reduced to 0.19 $kgCO_2e$/kWh.

Brown coal

Brown coal (lignite) has a low calorific value and large volumes are required for fuelling a power plant (especially in comparison with hard coal). Consequently most lignite power plants are mine-to-mouth, which means that the power plant is situated close to the mine thus not requiring energy intensive transport. IAEA's estimates of the total life cycle emissions from brown coal compare well with black coal as there is an assumption that the coal is not transported from other countries. Their estimate for brown coal ranges between

46 UCD Environmental Institute, 1997

47 IEA, 2008a, *Energy Technology Perspectives Scenarios and Strategies to 2050*

48 IPCC Working Group III, 2007, *Fourth Assessment Report*, Chapter: Energy supply

49 IPCC, 2007

50 IEA, 2008

0.8–1.7 $kgCO_2e/kWh$ and the 2020 expectation is for emissions to stay at the low end of the range (i.e. 0.8 $kgCO_2e/kWh$).The IPPC, quoting a number of sources, provides a life-cycle emissions range of just over 1.0 $kgCO_2e/kWh$ to below 1.4 $kgCO_2e/kWh$ (see Figure 1.14 above).

Due to the economics of brown coal (mine-to-mouth) only very small amounts are used in Ireland and this is likely to remain the case in the longer-term to 2030 and beyond.

Table 1.17 below summarises the life-cycle carbon emissions for generation power from different categories of coal expressed in $kgCO_2/kWh$ in 2010, 2020 and 2030.

Table 1.17: Carbon content of different categories of coal used in the Tetralemma Index in 2010, 2020 and 2030 in $kgCO_2/kWh$

Source	2010	2020	2030
Brown coal	0.8-1.7 (IAEA) 1.0-1.4 (IPCC/WEC)	0.8 (IAEA) 0.8 (IPCC) (low)	0.7 (extrapolation) (no CCS) 0.2 (IPCC) (with CCS)
Black coal	0.95-1.25 (IAEA) 0.8-1.0 (IPCC)	0.75 (IAEA)	0.7 (extrapolation (no CCS) 0.2 (IPCC) (with CCS)

Source: as indicated in the table

1.4.3 Supply and infrastructure vulnerability

Climate change is expected to have no or very limited impact on the coal supply chain and conversion technology infrastructure across the three time horizons – 2010, 2020, 2030. In general, power plants could be affected by loss of cooling water in the future as a result of climate change induced lower river flows. However, this is unlikely to affect Ireland as any new coal fired power plants will most probably be built on the coast, because as 100 per cent of coal in the country is imported this would be the most economically viable arrangement. An inland power station would mean considerable additional investment in domestic land transport infrastructure,which will also result in greater lifecycle carbon emissions. Thus any new plant will use sea water for cooling purposes.

Plants situated on coastal areas, in turn, could be subject to climate-induced flooding from storm surges, especially when combined with high tides.This scenario could also affect the existing Moneypoint plant which is situated on the coast by Cork in an area which has been explicitly mentioned as being at risk of extreme weather and inundation[51]. In the near to medium term (2010 and 2020) there is projected to be no effect on infrastructure. However,

51 The Irish Climate Analysis and Research Unit, 2000, NUIM (ICARUS)

as the likelihood of extreme weather conditions increases over time, there is projected to be some potential negative effect on infrastructure in 2030.

Climate change is expected to have no impact on the availability of coal as a fuel across the three time horizons – 2010, 2020, 2030.

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The Irish Energy Tetralemma

Fuel Report 2: Petroleum

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ Petroleum is one of the least competitive fuels in terms of cost. It is particularly expensive compared to other fossil fuels. ▪ There is no single price for oil – it has many varieties and is physically and financially traded in several markets. Most often used are the spot prices of West Texas Intermediate crude or Brent crude. As Ireland is directly reliant on the UK for petroleum the Brent crude price is the most pertinent. ▪ Using an average of World Bank, US EIA[1], IEA[2], and EU[3] real price forecasts, petroleum is predicted to remain stable yet relatively expensive in real terms: €8.20/GJ in 2010, €7.89/GJ in 2020, €8.55/GJ in 2030. ▪ Ireland does not have any indigenous petroleum reserves and buys petroleum at the international market price – currently and in the future. This means that the country is exposed to potential fluctuations in the market price of petroleum. ▪ Currently (and in the future), conventional and unconventional oil are traded as one commodity and there is no price differential.
Delivered energy cost	▪ Unlike most other fuels, the delivered cost of petroleum is not based upon its use in public thermal power production. As a result, it is more rational to base delivered energy cost on the price of delivering transport fuel. Like all fossil fuels, petroleum is currently a cheap source of delivered energy. ▪ As of mid 2009 delivered cost of energy from petroleum was approximately €11/GJ - this is based on current crude oil prices and a further cost of the refining process.
Policy & Regulation	▪ Oil is at a relatively significant disadvantage to other fuels in terms of policy and regulatory barriers and the lack of particular incentives for its use. ▪ At the European level, a range of regulatory burdens exist such as, EU Emissions Trading Scheme (EU ETS), EU directives on ambient air quality, EU Integrated Pollution Prevention and Control Directive, and the EU Auto Oil Programme. ▪ There is potential for oil's competitiveness, in the context of policy and regulation, to improve if carbon capture and storage (CCS) is supported at the national and EU levels. The EU framework already

1 United States Energy Information Administration

2 International Energy Agency

3 European Union

	aims to develop a number of strategic large-scale CCS facilities and the draft proposal for an EU Carbon Capture and Storage Directive will reinforce this, which Ireland can potentially benefit from.
Market context in Ireland	▪ Petroleum fuels completely dominate the transport sector in Ireland in terms of total energy consumption. Current consumer habits and infrastructure are based upon the supply and use of petroleum fuels for vehicles. As a result, any significant shift away from the use of petroleum fuels will likely be slow and incremental. ▪ The oil industry in Ireland is fully privatised, liberalised and deregulated with free access to the market. Oil companies must therefore compete on the basis of factors such as brand image, location, convenience, service, and price. ▪ There is a dense and mature infrastructure which supports all stages of petroleum fuels production and distribution in Ireland.

Security of supply

Import dependence	▪ All oil used in Ireland is imported, which makes the country highly import dependent. ▪ In addition, oil makes up the largest proportion of total primary energy requirement (TPER), accounting for over half. As a result, oil's weighted import dependence is the highest. ▪ In general, oil is expected to maintain its relative weighted import dependence position in the future, despite a very slight decline of its role in TPER.
Fuel place of origin	▪ Ireland ultimately sources the majority of its oil from Norway and Denmark, i.e. low risk countries. However in the long-term, these low-risk countries are unlikely to have remaining reserves. ▪ In the future, Ireland will have fewer options of where to source oil from and therefore may have to rely on countries with higher political and/or economic risk. ▪ By 2030, conventional oil is the least secure fuel in terms of place of origin.
Supply and infrastructure resilience	▪ Oil's supply and infrastructure requirement is less robust than coal but stronger than gas. Although tankers can move oil around the globe, transportation is difficult and increasingly expensive. Reliance on pipelines also adds to the complexity and fragility of the supply chains.
Market volatility	▪ Oil has the highest market volatility of all fuels researched. ▪ Remaining petroleum reserves are becoming increasingly concentrated in a handful of regions. Moreover, the remaining export nations are typically riskier in a political and economic

	sense. As a commodity oil's market security is therefore relatively low. ▪ The concentration of supply causes it to be susceptible to market shocks, as has happened in the past. Ireland is only a minor consumer in global terms and may find it difficult to maintain a stable supply as oil reserves dwindle.
Energy availability and intermittency	▪ With sufficient storage infrastructure, oil can be easily stored and it does not suffer from intermittency problems. It therefore scores highly in comparison to renewables, which are inherently intermittent.

Sustainability

Future longevity	▪ Conventional oil is among the fuels with the shortest longevity, whereas unconventional oil features the highest longevity among the finite (fossil) fuels. ▪ Best current global conventional oil **reserves-to-production ratio** is estimated to be just over 40 years. Combining the predicted levels of reserves with predicted rate of production suggests that the longevity of oil is declining. In 2010, approximately 40 years will remain, by 2020 this may be reduced to 27 years, and by 2030 just 16 years of oil may remain. ▪ Current estimates suggest the reserves of unconventional oil are vast, particularly in the Canadian oil sands and Venezuela's ultra-heavy oil. As production of unconventional oil is still in its infancy it is not yet at full capacity. Production is therefore expected to increase. Best estimates suggest that in 2010, approximately 435 years may remain, by 2020 this may be reduced to 275 years, and by 2030 210 years of unconventional oil may remain. ▪ Like all fossil fuels, oil's score declines over time as reserves diminish, whilst renewables will remain available indefinitely.
Environmental impact	▪ The environmental impact of upstream operations tends to become much more pronounced when considering unconventional oil sources, although these are complex and relatively poorly understood. ▪ Downstream impacts are believed to account for the majority of externalities associated with oil and mainly refer to health impacts from atmospheric pollution. The scale of the impact however, is highly dependent on the population density of the area surrounding the oil facility (refinery, power plant, etc.) (ExternE, 1998). Therefore, these can be significantly reduced when facilities are located in a less densely populated area.

Climate change

Carbon content	▪ The IPCC provide a range for the carbon content of oil and oil products. The stated value for crude oil is 73.3 tCO_2/TJ. This value is used in the Tetralemma Index for conventional oil. The cited value for oil shale and tar sands oil is 107 tCO_2/TJ and is used in the Tetralemma Index for unconventional oil. The carbon content remains the same for both types of oil for 2010, 2020 and 2030.
Lifecycle carbon footprint	▪ Oil as a transport fuel (the focus of this report) has the lowest lifecycle carbon footprint among all fossil fuels researched. This is primarily due to its direct use in internal combustion engines, which is much more efficient (in terms of utility) than the fossil-fired power generation plants (the main use of the other fossil fuels researched).
Supply and infrastructure vulnerability	▪ There is some likelihood that there will be some impact on the North Sea oil and gas operations as a result of climate change. Damage to infrastructure in this region will affect Ireland as this is where much of the country's oil and gas are imported from. Increased wave action, storm surges, and coastal erosion may necessitate design changes to conventional offshore and coastal facilities.
Availability change	▪ Oil is a fossil fuel and as such its availability is not affected by climate change.

2.1: Petroleum: the basics

Petroleum, or crude oil, is a naturally occurring flammable liquid found within the Earth's crust. After water, petroleum is the second most abundant liquid on Earth. It is typically found in porous and permeable reservoir rocks. Crude oil is a mixture of hydrocarbons from almost solid to gaseous. On average, crude oils are composed of mainly carbon (~84 per cent), hydrogen (~14 per cent), and sulphur (~2 per cent), plus smaller amounts of nitrogen, oxygen, metals and salts. Its appearance can change depending on where it originates – from almost colourless to thick and black. Crudes from different sources have different make-ups - some have more of the valuable lighter hydrocarbons and others have more of the heavier hydrocarbons.

The petroleum industry generally classifies crude oil by the geographic location it is produced in (e.g. West Texas, Brent, or Oman), its density, and by its sulfur content. Crude oil may be considered *light* if it has low density or *heavy* if it has high density; and it may be referred to as sweet if it contains relatively little sulphur or *sour* if it contains substantial amounts of sulphur.

Crude oil becomes most useful once the hydrocarbons are separated out in the oil refinery process. Different hydrocarbon chain lengths all have progressively higher boiling points, so they can all be separated by distillation.Each different chain length has a different property that makes it useful in a different way, see Table 2.1.

Table 2.1: Petroleum products

Carbon atoms	Oil product	Uses
Few	Petroleum gas	Used for heating, cooking, making plastics.
	Naphtha / ligroin	Intermediate that will be further processed to make gasoline.
	Gasoline	Motor fuel.
	Kerosene	Fuel for jet engines and tractors; starting material for making other products.
	Gas oil or diesel distillate	Used for diesel fuel and heating oil; starting material for making other products.
	Lubricating oil	Used for motor oil, grease, other lubricants.
	Heavy gas / fuel oil	Used for industrial fuel; starting material for making other products.
Many	Residuals	Solids such as coke, asphalt, tar, waxes; starting material for making other products.

Source: SQW Energy

Oil can broadly be classified into conventional oil, which is typically extracted from wells, and unconventional oil. Unconventional oil is an umbrella term for oil resources that are typically more challenging to extract than conventional oil. These include tar sands, oil shale and heavy oil. Non-conventional sources of oil may be increasingly relied upon as conventional sources are depleted; however conventional sources of oil are currently preferred because they provide a much higher ratio of extracted energy to energy used in the extraction and refining processes. In addition, unconventional oil has only recently become cost competitive.

2.2: Petroleum as a commodity

2.2.1 Global reserves

According to the World Petroleum Council's definition, the total initially-in-place (IIP) petroleum resources is the quantities of petroleum – both conventional and unconventional – estimated to exist in naturally occurring accumulations. IIP resources include the quantities contained in known accumulations, those quantities already produced and those quantities in accumulations yet to be discovered. The estimates therefore include both recoverable and unrecoverable resources. The US EIA estimates 20.8 trillion barrels of global IIP resources. Of that, approximately 40 per cent is conventional crude oil and the remainder is unconventional petroleum resources.

Conventional oil reserves

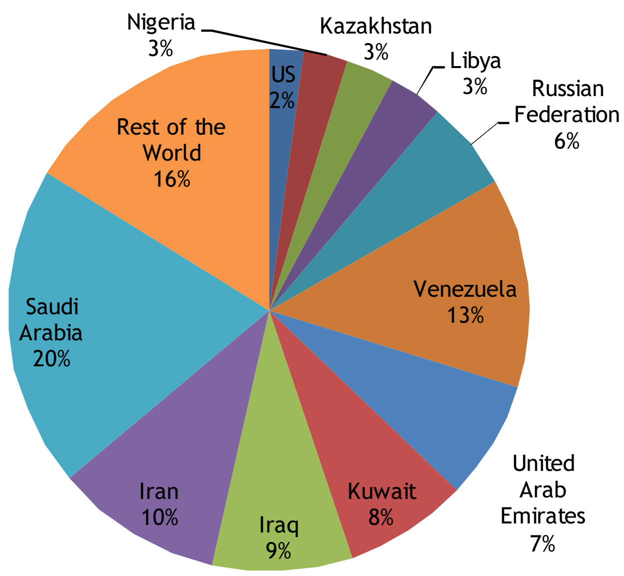
There is no single definitive estimate for the proven global reserves of oil. At the end of 2007, total proven oil reserves were estimated to range from 1.24 trillion barrels (BP, 2008[4]) to 1.33 trillion barrels (Oil & Gas Journal, quoted in US EIA 2008a[5]).Current reserves-to-production ratios suggest that just over 40 years of oil may remain. Estimates produced by the World Energy Council (WEC 2007), BP (2008), and US EIA are all grouped between 41 and 43 years. Reserves in the European Union are likely to have under a decade of production left, whereas OPEC reserves are estimated to last over 70 years.

The global reserves are spread across over fifty countries, however neraly 50 per cent of the world's remaining reserves are concentrated in just four countries: Saudi Arabia, Iran, Iraq and Kuwait. In addition, approxamately 75 per cent of remaining reserves are currently held by OPEC members. (See Figure 2.1 below).

4 The BP estimates are compiled using a combination of primary official sources, third party data from the OPEC Secretariat, World Oil & Gas Journal and an independent estimate of Russian reserves based on information in the public domain

5 US EIA, 2008a, *International Energy Outlook 2008*

Figure 2.1: Proportion of global proven oil reserves, by country (2009)



Source: BP (2010)

The US EIA's International Energy Outlook 2008 predicts that global conventional oil production will rise by 26 per cent between 2005 and 2030, from 82 Mboe[6] per day to 103 Mboe per day. Similarly, the 2007 update of the EU European Energy and Transport Trends to 2030 forecasts global oil consumption to increase from 3,632 Mtoe[7] in 2001 to 5,545 Mtoe in 2030. This represents a growth of 53 per cent over the period please see Table 2.2 below.

Table 2.2: Global oil consumption forecast to 2030

	2001	2010	2020	2030
EC DG TREN (Mtoe)	3,632	4,153	5,020	5,545
US EIA (Mboe per day)	-	84.8	93.9	102.9

Source: EU (2007) European Energy and Transport Trends to 2030

By some distance, the largest consumer of oil is the USA. In 2007, consumption of oil in the USA accounted for 24 per cent of global consumption (BP, 2008[8]). Other large consumers include China (9.3 per cent), Japan (5.8 per cent), India (3.3 per cent), and Russia (3.2 per cent). Ireland is a relatively small player in the global market, accounting for just 0.2 per cent of global consumption. This is a similar level to countries such as Ecuador and New

6 Million barrels of oil equivalent

7 Million tonnes of oil equivalent

8 BP, 2008, *Statistical Review of World Energy*

Zealand. As oil stocks decrease, Ireland is likely to face stern competition in the global markets.

A more detailed examination of the actual estimates for global reserves and production levels is provided in Table 2.3 below. These are highly dependent on estimated future production forecasts.

Table 2.3: Forecast Oil reserves 2010, 2020, 2030

	Production (Mboe)	Reserves (Mboe)	Years remaining
2007	29,800	1,330,000	44
2010	30,952	1,242,348	40
2020	34,274	932,828	27
2030	37,559	590,093	16

Source: EC DG TREN, US EIA, BP, WEC, WCI

Unconventional oil reserves

The largest resources of unconventional oil are estimated to be in Canada, Venezuela and the USA. Of the 1.7 trillion barrels in-place in the tar sands of Alberta, Canada, around 173 billion are of recoverable oil (Alberta Department of Energy 2007). The Alberta oil sands cover 140,000 km^2; an area just larger than the entire country of England. Production in 2006 was approximately 1.26 million barrels per day according to the Alberta Energy and Utilities Board and expected to grow to three million barrels by 2030 (Simbeck)[9], 2006 and Canadian National Energy Board, 2007). Similarly, 272 billion barrels of recoverable oil ('extra heavy crude') is estimated to exist in the Orinoco Belt in Venezuela. An estimated 0.5 million barrels per day were being extracted from the Orinoco Belt in 2006.

Table 2.4 below shows US EIA[10] published forecast estimates of unconventional oil production. For the Canadian oil sands production is expected to more than double between 2010 and 2030 whilst Venezuelan ultra-heavy oil production is forecast to grow by approximately 50 per cent.

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9 Presentation given at the US EIA Energy Outlook and Modelling Conference in 2006

10 US EIA, 2008a, *International Energy Outlook 2008*

Table 2.4: Unconventional oil forecast production (million barrels of oil equivalent per day)

	2010	2020	2030
Oil Sands (Canada)	1.9	3.3	4.2
Ultra-Heavy Oil (Venezuela)	0.9	1.0	1.3

Source: US EIA (2008a[11]), US EIA (2007)

Given these forecast production rates and the estimated total reserves, a conservative estimate of the combined reserve to production ratio of the Canadian and Venezuelan unconventional oil is approximately 435 years in 2010. It must be noted however, that as production increases and more efficient recovery techniques are utilised, this ratio reduces significantly in future years. By 2020 the ratio is around 275 years and by 2030 the figure falls to just under 210 years.

Estimates of the USA's oil shale resources range from 1.5 trillion barrels (Simbeck 2006) to 2.1 trillion barrels (US EIA 2008). Oil shale is the most technically and economically challenging unconventional oil resource and there are only estimates as to what proportion may be recoverable. The mid-point currently used by the US government is 800 billion barrels (WWF/Co-operative Group 2008). These references agree that oil shales are likely to play only a very minor role in global oil supply before 2030.

Peak oil

'Peak oil' is the term used to describe the situation whereby global oil production reaches a point where it can no longer increase any further. From that point in time, future oil production will continue to decline. The exact timing of peak oil output is difficult to ascertain given the numerous uncertainties such as likely output and the future discovery of new oil fields. However, despite these ambiguities, it is already an established fact that since the 1980s the world has annually consumed more oil than it has discovered.

Forfás (2006) published research that compiled estimates of the projected date for peak oil[12]. The research consulted a range of experts, oil companies, governments and energy advisory organisations. Although there was a wide variation of estimates ranging from 2007 to 2035, a consensus emerged that non-OPEC oil production is likely to peak around 2010.

Table 2.5 below summarises the level of oil longevity expressed as the reserves-to-production ratio over the three timescales - 2010, 2020 and 2030 for both conventional and unconventional oil. Given the sensitivity of longevity to the future oil production estimates, for the purposes of, we have combined the current projections for oil production with the current level of global reserves.

11 US Energy Information Administration (US EIA), 2007, *International Energy Outlook 2007*

12 Forfás, 2006, *A baseline assessment of Ireland's oil dependence*

Table 2.5: Projected oil longevity in 2010, 2020 and 2030 in years remaining

	2010	2020	2030
Conventional oil - Average value	40	27	16
Unconventional oil - Average value	434	276	208

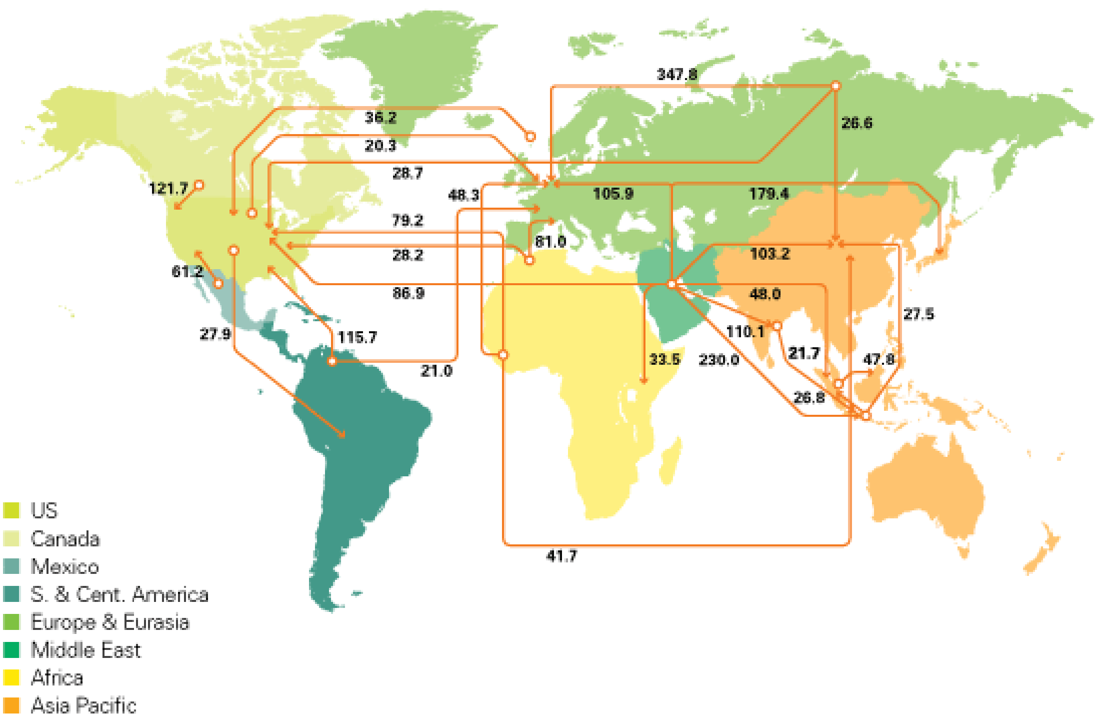
Source: various - as described in the paragraphs above

It should be noted however that the acceptance of the peak oil hypothesis is becoming more widespread. The chief economist of the International Energy Agency (IEA), believes that if no big new discoveries are made, “the output of conventional oil will peak in 2020 if oil demand grows on a business-as-usual basis.” The IEA 2009 energy outlook states that conventional oil is “projected to reach a plateau sometime before” 2030. (Economist (2009)).

2.2.2 Global production and trade

Almost 38 million barrels of crude oil are traded daily (BP, 2010). The Middle East accounts for almost 45 per cent of crude oil exports, whilst the largest importers are Europe (27 per cent) and the USA (25 per cent). Figure 2.2 below shows the combined major trade movements of crude oil and oil products in 2009.

Figure 2.2: Crude oil and oil products major trade movements, 2009



Source: BP (2010)

Ireland currently sources around 85 per cent of its oil from Norway and the remainder from Denmark, UK, Algeria and Libya (SEI 2007b[13]). The most recent data suggest that at current production rates Norway may have less than a decade of oil reserves remaining (BP, 2008[14]).

Table 2.6 below suggests that Ireland currently has a low-risk oil supply due to the dominance of Norway; a low-risk country.

Table 2.6: Country Risk and ease of doing business indicators

Country	Proportion of Ireland's oil supply (SEI 2007)	OECD Country Risk Classification 2008 (score from 0-7, higher figure equals higher risk)
Norway	83 per cent	0
Denmark	10.3 per cent	0
UK	3.2 per cent	0
Algeria	2.6 per cent	3
Libya	0.8 per cent	6

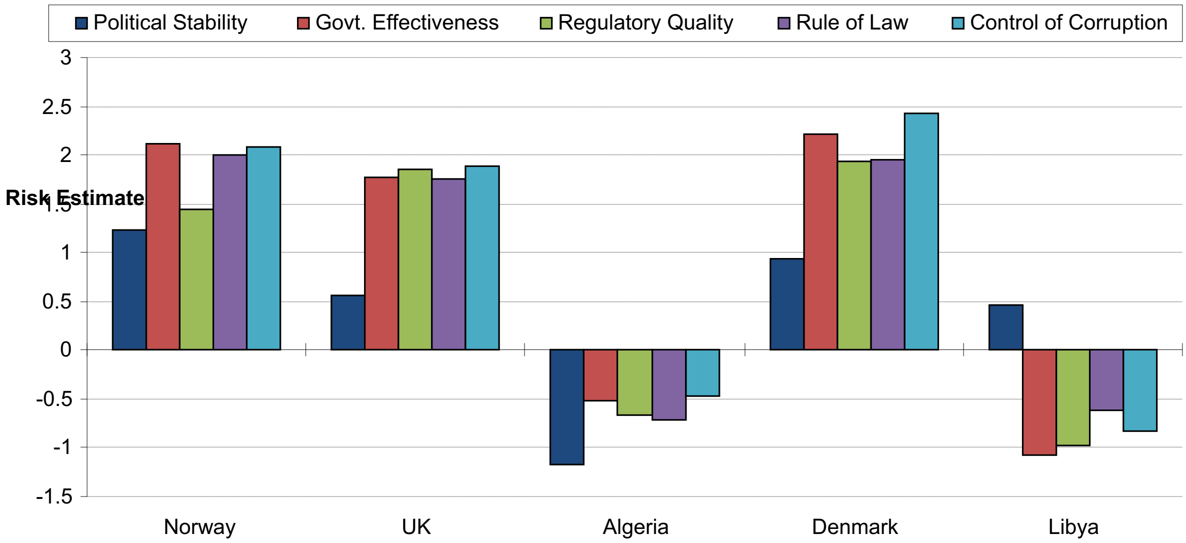
Source: OECD

Figure 2.3 below illustrates current socio-political risk as measured by the World Bank's World Governance Indicators. A similar picture is evident, with Norway, Denmark and the UK posing very little risk but Algeria and Libya being somewhat riskier.

13 SEI, 2007b, *Security of Supply in Ireland*

14 BP, 2008, *Statistical Review of World Energy*

Figure 2.3: World Bank's World Governance Indicators 2008



Source: World Bank. Note: The risk estimates are normally distributed with a mean of zero. Almost all values lie between -2.5 and 2.5.

There is no readily available information on future estimates for country risks and political stability. Therefore, for the purposes of calculating the Tetralemma Index, the current World Bank and OECD indicators are used. The methodology, however, takes into account the possible future mix of countries that will comprise the main oil exporters (on the basis of proven reserves and current willingness to export). The security of Ireland's energy supply is therefore likely to be somewhat weaker in 2020 and 2030.

2.2.3 Oil Prices

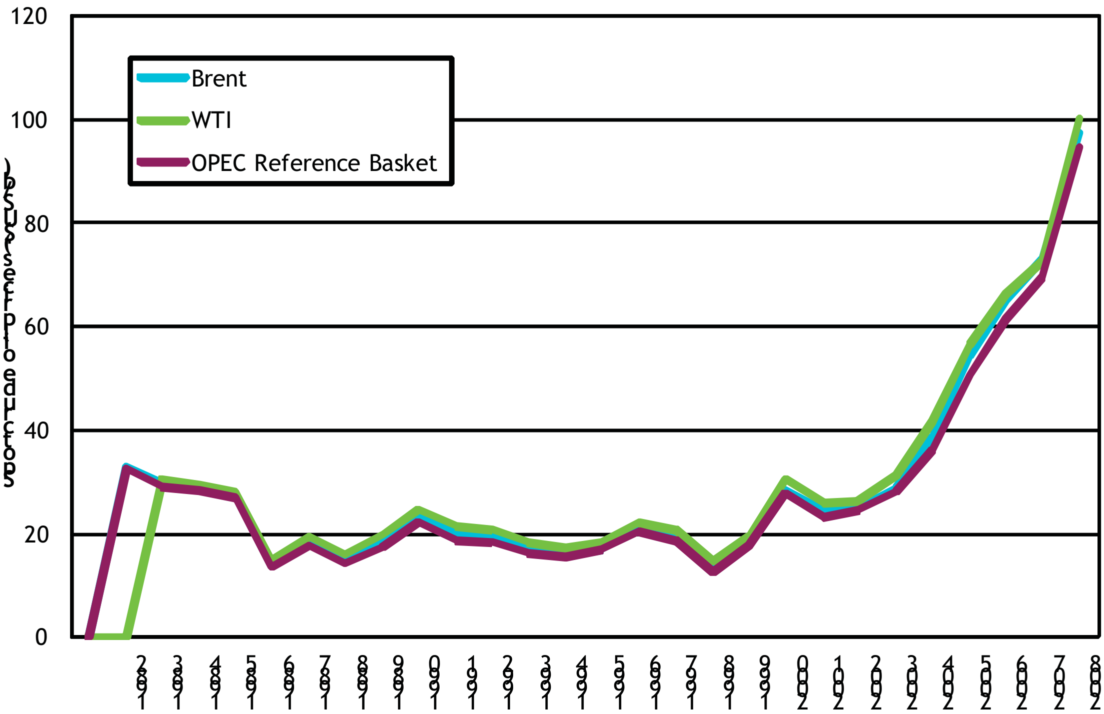
Oil markets

There are a number of collection methods and classifications for the price of petroleum. Most often used are the spot prices of either West Texas Intermediate (WTI) crude as traded on the New York Mercantile Exchange (NYMEX) for delivery in Cushing, or of Brent crude as traded on the Intercontinental Exchange (ICE) for delivery at Sullom Voe. Other important benchmarks include Dubai, Tapis, and the OPEC basket. The US Energy Information Administration (EIA) uses the 'Imported Refiner Acquisition Cost', which is the weighted average cost of all oil imported into the US, as its 'world oil price'.

Oil prices

The nominal price of crude oil has risen considerably over recent years. All three varieties of crude oil depicted in Figure 2.4 escalated from under US$15 per barrel in 1998 to around US$95 per barrel in 2008.

Figure 2.4: Spot crude oil prices, 1998-2008



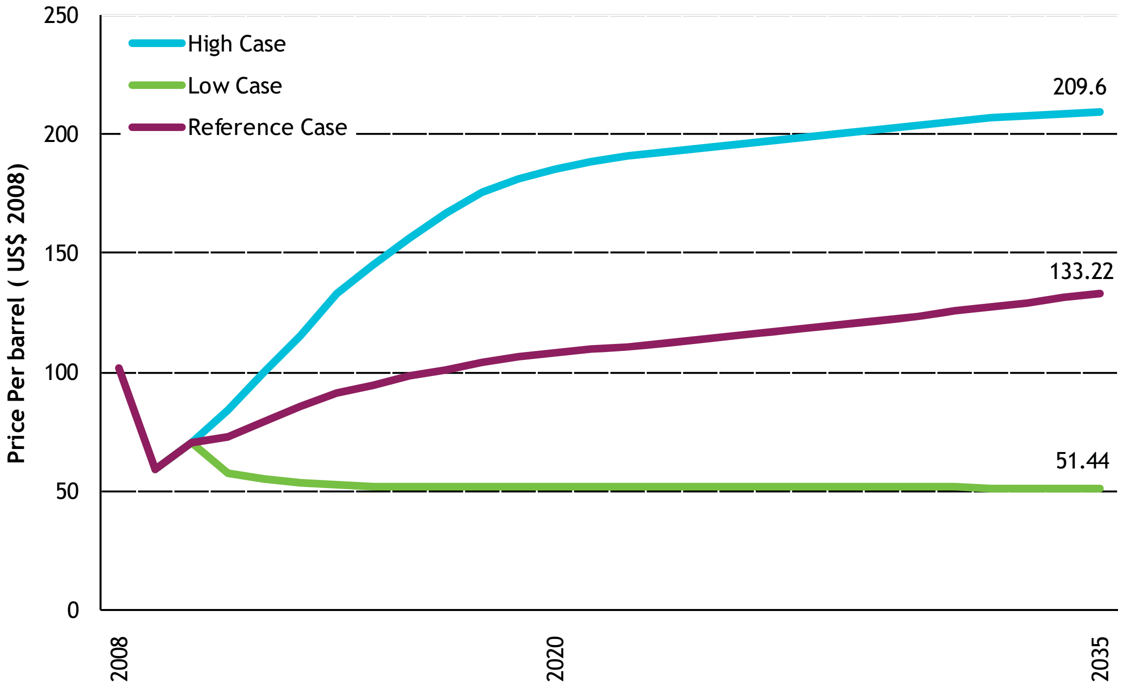
Source: OPEC, 2008

More recently, the price of crude oil in 2008 has risen further. Since January 2008, WTI traded on the NYMEX was persistently valued at over US$100 per barrel. Throughout the first six months, the price rose steadily, peaking at US$147 per barrel in July 2008. In late summer, the price returned to around US$90 – US$100 per barrel and has continued to decrease into the latter quarter of the year to less than US$70 per barrel. But as of March 2010 the price is around US$80 per barrel. (March 2010 US$81.20) (US EIA).

A variety of factors have been suggested for causing the 2007/8 price increases. These include strong demand growth in Asia and the Middle East, no growth in OPEC members' production since 2005, rising supply costs for oil exploration and development, general across-the-board increases in commodity prices, and the low value of the US dollar.

The US EIA National Energy Modelling System presents projections and analysis of the world oil price to 2030. The 'reference case' forecast assumes that current policies affecting the energy sector remain unchanged throughout the projection period. The reference case provides a clear basis against which alternative cases and policies can be compared. A high-price scenario and a low price scenario are presented along side the reference case (see Figure 2.5 below).

Figure 2.5: Real world oil price forecasts in three scenarios



Source: US EIA (2010)

The high price scenario suggests the real world oil price (at 2008 prices) will rise from US$70 in 2010 to US$185 in 2020 and then US$209 by 2035. The medium term price falls in the reference and low price cases rely upon new production, of both conventional and unconventional fuels, in areas such as Azerbaijan, Brazil, Canada, USA, and Kazakhstan.

World Bank commodity price data show average world prices for crude oil[15]. In June 2010, the average real world price was estimated to be US$74 per barrel. World Bank forecasts expect the average price to rise to US$80/bbl in 2020. The forecast reflects the levels of oil required to develop high-cost oil sands in Canada, and assumes continued production restraint by major producers.

Unconventional oil production prices

A report published by Canada's National Energy Board (2006) provides information on unconventional oil produced in Canada. The estimated operating costs range from US$18 to US$22 (2006 prices) per barrel of Canadian unconventional crude oil and the estimated supply costs range from US$36 to US$40 per barrel. Supply costs include operating costs, capital costs, taxes, royalties and the rate of return on investment. These cost estimates are dependent on capital and production costs, non-fuel operating costs and the price of natural gas. Changes to these will have an impact on the estimated costs of supplying unconventional crude oil.

Rand (2008) and Lacombe and Parsons (2007) provide similar analysis to suggest that the unit production costs of a barrel of Canadian unconventional oil to be in the region of US$34 to

15 Average spot price of Brent, Dubai and West Texas Intermediate, equally weighed

US$37 (2005 prices). Future prices are estimated to range from US$27 to $36 in 2025 without carbon capture and storage and from US$31 to US$45 with carbon capture and storage (Rand, 2008).

The prices given above for oil produced from Canadian oil sands are effectively the 'break-even' prices for the producers. It is anticipated that once the oil is processed into crude oil its market-price is indistinguishable from that of conventional crude oil.

Table 2.7 below summarises the range of projected oil prices in 2010, 2020 and 2030 from a range of reference sources, as discussed above.

Table 2.7: Projected oil prices in 2010, 2020 and 2030 in US$ per barrel (NB: same values for conventional and unconventional oil)

Source	2010	2020	2030
IEA	59.03	-	62.00
World Bank	77.70	57.90	-
US EIA (reference case)	67.00	60.00	70.00
BERR (central scenario)	65.00	70.00	75.00
European Commission	54.50	61.10	62.80
Average value	**64.70**	**62.30**	**67.50**

Source: as shown in the first column

2.2.4 Weighted import dependence

Oil in Ireland's energy mix

Ireland consumed almost 9 million tonnes, or approximately 65 million barrels, of oil in 2007. Oil dominates Ireland's total primary energy requirement (TPER), accounting for 55 per cent of the total in 2007 (SEI 2008a[16]).

Around 63 per cent of Ireland's total oil energy-inputs are accounted for by the transport sector alone. In the transport sector 99.5 per cent of total fuel usage was supplied by oil based products. Diesel was responsible for the largest share of total transport-fuel usage, accounting for 47 per cent in 2007. Gasoline was second with 34 per cent and kerosene was third with 18 per cent of total transport-fuel consumption.

Between 1990 and 2007 oil's share of Ireland's total energy requirement has increased from 47 per cent to 55 per cent. Ireland is aiming to reduce its reliance on oil in the fuel mix. Based on Sustainable Energy Ireland's (2007a) figures oil is expected to contribute 53 per cent to TPER in 2010 and 52 per cent in 2020. The main routes for achieving reductions in oil

16 SEI, 2008a, *2007 Provisional Energy Balance*

consumption in Ireland are expected to be through incentives in other areas, such as the promotion of biofuels, public transport use and combined heat and power systems.

Import dependence

Ireland has no indigenous oil production or interconnecting pipeline infrastructure. Ireland is totally reliant on seaborne imports for use in Ireland's only oil refinery at Whitegate, Co. Cork. Finished products not supplied through the refinery are chiefly sourced from refineries on the UK west coast.

***Whitegate refinery**, Co. Cork. The refinery is able to supply around 40 per cent of Ireland's fuel needs. In February 1997 the Irish Refining plc took the decision to upgrade the refinery to 75,000 barrels per day. The upgrade cost an estimated €86 million. Off the coast of the Cork Harbour there is an 8.5 million barrel deep water crude oil and oil products storage complex located in Bantry Bay. Whitegate produces low sulphur gasoline and diesel fuels and has been owned by ConocoPhillips since 2001. According to ConocoPhillips Whitegate has the ability to produce 18,000 barrels a day of gasoline and 30,000 barrels a day of diesel and jet fuel.*

Table 2.8 below summarises the sub-indicators that comprise the weighted import dependence indicator for oil in Ireland over the three timescales - 2010, 2020 and 2030. The 'share of the fuel mix' figures for unconventional oil are based on the estimated proportion of total global oil production likely to be from unconventional sources. All figures for 2030 are calculated by applying SEI's projection for growth between 2010 and 2020 through to 2030.

Table 2.8: Projected share of fuel mix and import dependence for oil in 2010, 2020 and 2030 in %

Sub-indicators	Conventional oil			Unconventional oil		
	2010	2020	2030	2010*	2020	2030
Share of the fuel mix	53%	50%	48%	0%	2%	3%
Import dependence	100%	100%	100%	100%	100%	100%
Weighted import dependence	**53%**	**50%**	**48%**	**0%**	**2%**	**3%**

Source: SQW Energy based on literature review

2.3: Oil in the energy system

2.3.1 Delivered energy cost

With regards to energy use, petroleum is predominately used in the transport sector and to a lesser extent by the residential and industrial sectors. Only a small proportion goes directly into public thermal power plants. As a result, it is rational to analyse the delivered energy cost of oil in terms of transport fuel prices.

The delivered energy price is equal to the price of crude oil plus the cost of refining. According to US EIA (2008c[17]) 75 per cent of the delivered energy cost is dependent on the price of crude oil and 25 per cent is added on through the refinery process. The full consumer price also includes taxes and distribution/marketing costs. As illustrated earlier in this paper, data are readily available for crude oil prices. Table 2.9 below shows the delivered energy costs for petroleum using the previously reported crude oil prices.

Table 2.9: Projected delivered energy cost in 2010, 2020, 2030

	2010	2020	2030
Average crude oil price (US$ per barrel)	64.70	62.30	67.50
Estimated refinery cost (US$ per barrel)	21.55	20.75	22.50
Delivered energy cost (US$ per barrel)	86.25	83.05	90.00
Delivered Energy cost (€/GJ)	**10.93**	**10.53**	**11.41**

Source: SQW Energy

Using the delivered energy values in Table 2.9, US $86.25 per barrel of oil equates to approximately 41 Euro cents per litre[18]. This approach can be considered a 'top-down' estimate of the delivered energy cost. Recent data produced by Maxol (04-Dec-08), an Irish oil company, allows a 'bottom-up' assessment of this figure. Maxol suggests the consumer price of Commercial DERV is 112 Euro cents. Once taxes (VAT and Excise duty) are removed from the price the cost falls to 56 Euro cents. US EIA (2008c[19]) also suggest that approximately 5 per cent of the total consumer price should also be subtracted for distribution/marketing purposes. The resultant 'bottom-up' estimate for Irish delivered energy costs for petroleum is therefore 51 Euro cents.

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17 US EIA, 2008c, *What consumers should know*, Domestic fuel prices

18 Assuming $1 = €0.75 and 159 litres in a barrel of oil

19 US EIA, 2008c, *What consumers should know*, Domestic fuel prices

2.3.2 Oil – conversion technologies

Transport accounts for over half of the world's oil use and the sector presents huge challenges for achieving reductions in fuel use and carbon emissions. Improving the fuel economy of vehicles is one of the most cost-effective measures currently available. The IEA (2008a[20]) suggests that available technologies have the potential to reduce the energy use per kilometer of new vehicles by up to 30 per cent in the next 15 to 20 years. These efficiencies can be made through low-cost 'incremental' technologies such as improved engine/drive train efficiencies, tyres, aerodynamics and accessories like air conditioning.

More advanced technologies such as fuel cells and on-board energy storage (i.e. batteries and H_2 storage) are still a number of years away from technical maturation or cost-effectiveness. IEA's (2008a) technology roadmaps suggest the current minimal commercialisation of plug-in electric vehicles and hybrid-electric vehicles can be advanced through research and development and deployment occurring in battery manufacturing companies and the further development of Li-ion batteries. Hydrogen fuel cell vehicles are not expected to be ready for commercial deployment before 2020.

2.3.3 Policy and regulation

A number of European-wide regulations exist which seek to influence the use of petroleum based fuels. These are primarily concerned with limiting pollutants.

- EU Emissions Trading Scheme aims to increase the marginal cost of fossil fuel use through establishing a price for carbon emissions. This scheme covers both power generation and oil refineries.
- A series of EU directives on ambient air quality limit values and thresholds for particular pollutants. Those included are nitrogen oxides, sulphur dioxide, lead and particulates, benzene and carbon monoxide.
- The Integrated Pollution Prevention and Control Directive (IPPC) imposes a requirement for industrial and agricultural activities with a high pollution potential to have a permit which can only be issued if certain 'Best Available Techniques' are met. The companies themselves bear responsibility for preventing and reducing any pollution they may cause, effectively enforcing minimum standards for polluting industries.
- The terms of the EU Auto Oil Programme which specifies stringent standards for a number of pollutants in petrol and diesel were fully transposed into Irish law during 1999 and 2000. The maximum sulphur content for both petrol and diesel fuels was set at 50mg/kg from 1 January 2005.

During the course of this research no particular incentives associated with using oil as a fuel were identified.

2.3.4 Supply chain and infrastructure resilience

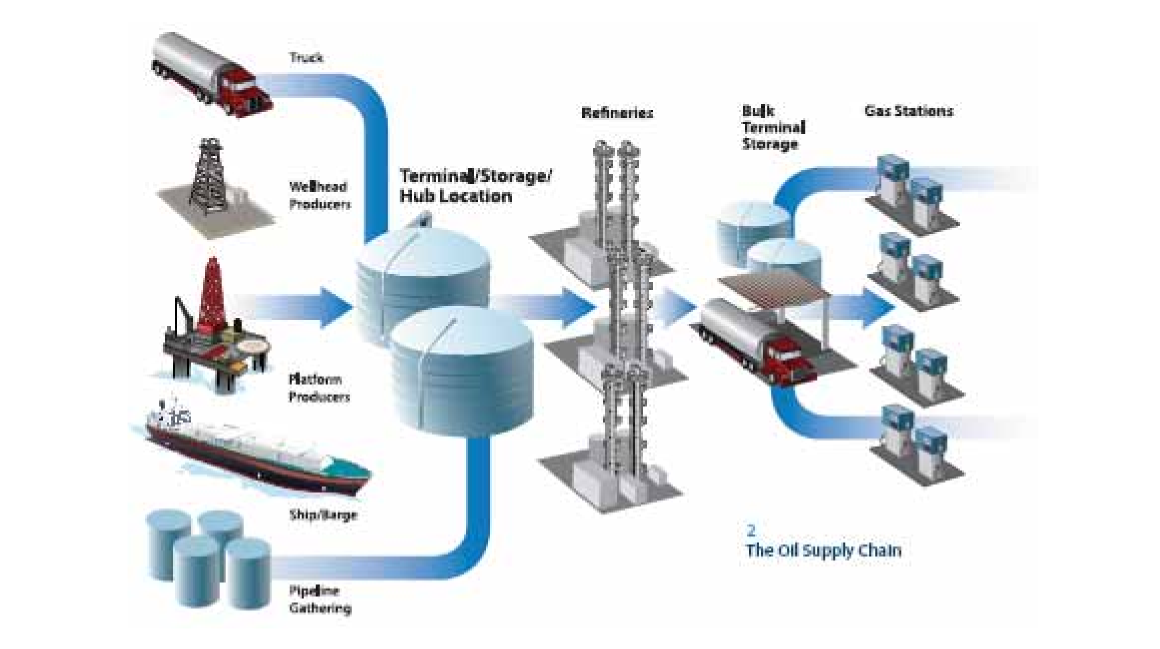
The oil supply chain is composed of three major processes, as shown in Figure 2.6 below;

- Production, which involves finding, extracting and transporting crude oil;

20 IEA, 2008a, *Energy Technology Perspectives Scenarios and Strategies to 2050*

- Refining, the process by which crude oil is turned in to products such as diesel; and
- Distribution, which focuses on moving the refined products to consumers.

Figure 2.6: Oil supply chain



Source: American Petroleum Institute (2008)

There are several modes of transportation for carrying crude oil from the producing country, to the customers. These include: water, pipeline, railway, and highway. Most of the crude oil produced in the North Sea, which Ireland currently relies upon, is pumped by pipeline to the major offshore receipts terminals such as Sullom Voe in the Shetlands (and other equivalent terminal facilities in Norway). Tankers then typically carry the oil from the exporting country to overseas importing countries.

Transportation of oil is difficult and increasingly expensive. Since the global supply of petroleum and oil is dominated by countries in the Middle East, transportation is a large part of the supply chain. Overseas transportation via tankers typically adds US$1-US$2 per barrel for western markets. Transporting oil overseas can be dangerous as accidents cause a major loss in revenue and are harmful to the environment. In addition, accidents can foster major spikes in oil prices.

Reliance on pipelines also adds another level of complexity and fragility to the supply chain. Pipelines are liable to several problems including corrosion, accidental damage during construction and intentional sabotage. Fixing pipelines is both disruptive and expensive as the broken pipeline must be closed and oil production from the oil field feeding the line has to stop.

2.3.5 Market context in Ireland

Petroleum based fuels dominate the Irish transport sector. They account for over 99.5 per cent of energy consumption in the sector, whilst less than half of one per cent is accounted for by liquid biofuel. Final energy use in the transport sector has grown by 167 per cent (6.3 per cent per annum on average) between 1990 and 2006; the fastest growth rate of all sectors (SEI 2007d[21]). Ireland is currently heavily reliant upon petroleum fuels and this is not expected to change in the short to medium term. The additional infrastructure requirements of shifting the Irish transport sector away from petroleum, i.e. consumers switching to alternative engines and installing new distribution/ supply stations, mean that change is likely to be slowly implemented.

The oil industry in Ireland is fully privatised, liberalised and deregulated with free access to the market. Oil companies must therefore compete on the basis of factors such as brand image, location, convenience, service, and price.

2.3.6 Market volatility

Remaining petroleum reserves are becoming increasingly concentrated in a handful of regions. It is likely that the number of export nations will decline in future years. Moreover, the remaining export nations are typically riskier in a political and economic sense. As a commodity oil's market security is therefore relatively low. The concentration of supply causes it to be susceptible to market shocks, as has happened in the past. Ireland is only a minor consumer in global terms and may find it difficult to maintain a stable supply as oil reserves dwindle.

2.3.7 Environmental impacts

Environmental impacts arising from the use of oil occur both upstream and downstream. Upstream impacts relate to damages to the land and marine environment (in the case of extracting the oil from e.g. the North Sea), accidents during transportation, and airborne pollutants in refineries. European Commission externality studies show that these upstream activities account for 7 per cent of total externalities as documented for different countries such as Italy, Greece and the UK (ExternE, 1998[22]).

The environmental impact of upstream operations tends to become much more pronounced when considering unconventional oil sources, although these are complex and relatively poorly understood (ISEEE, 2006[23]).

Downstream impacts are believed to account for the majority of externalities associates with oil and mainly refer to health impacts from atmospheric pollution. The scale of the impact, however, is highly dependent on the population density of the area surrounding the oil facility

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21 SEI, 2007d, *Energy in Transport*

22 CIEMAT, 1998, *ExternE: Externalities of Energy Vol XX: National Implementation*. Published by the European Commission

23 ISEEE, 2006, *Life Cycle Assessment of Oil Sands Technologies*

(refinery, power plant, etc.) (ExternE,1998). Therefore, these can be significantly reduced when facilities are located in a less densely populated area.

IPCC on recovering oil from tar sands

Technologies for recovering tar sands include open cast (surface) mining where the deposits are shallow enough (which accounts for 10 per cent of the resource but 80 per cent of current extraction), or injection of steam into wells *in situ* to reduce the viscosity of the oil prior to extraction. Mining requires over 100m^3 of natural gas per barrel of bitumen extracted and in situ around 25m^3. In both cases cleaning and upgrading to a level suitable for refining consumes a further 25–50m^3 per barrel of oil feedstock. The mining process uses about four litres of water to produce one litre of oil but produces a refinable product. The in situ process uses about two litres of water to one of oil, but the very heavy product needs cleaning and diluting (usually with naphtha) at the refinery or sent to an upgrader to yield syncrude at an energy efficiency of around 75per cent (NEB, 2006).

The energy efficiency of oil sand upgrading is around 75 per cent. Mining, producing and upgrading oil sands presently costs about US$15/bbl (IEA, 2006a[24]) but new greenfield projects would cost around US$30–US$35/bbl due to project-cost inflation in recent years (NEB, 2006[25]). If CCS is integrated, then an additional US$5 per barrel at least should be added. Comparable costs for conventional oil are US$4–US$6/bbl for exploration and production and US$1–US$2/bbl for refining. Mining of oil sands leaves behind large quantities of pollutants and areas of disturbed land.

Source: IPCC

Table 2.10 below summarises the level of environmental impacts (externalities) expressed as Euros per mega-watt hour of power generated (€/MWh) over the three timescales - 2010, 2020 and 2030. Whilst power generation is not the main application of oil in Ireland, this metric does capture the key stages of the oil supply chain and is therefore indicative of the externality cost. It is also useful as a comparison with other fuels. Given that only current externality costs are reported in the literature, this study assumes that these costs will remain the same in real terms over the timescale discussed.

24 IEA, 2006, *Towards an oil free economy in Ireland*

25 Canadian National Energy Board (CNEB), 2006, *Canada's Oil Sands-Opportunities and Challenges to 2015: An Update*

Table 2.10: Environmental Impact of oil - externality cost - in 2010, 2020 and 2030 in €/MWh

	2010	2020	2030
Conventional oil	70	70	70
Unconventional oil	100	100	100

Source: ExternE

2.4: Oil and climate change

2.4.1 Carbon content of fuel

The IPCC provide a range for the carbon content of oil and oil products. The stated value for crude oil is 73.3 tCO_2/TJ and the cited value for oil shale and tar sands oil is 107 tCO_2/TJ. The carbon content remains the same for both types of oil for 2010, 2020 and 2030.

ISEEE on carbon emissions associated with recovering oil from tar sands

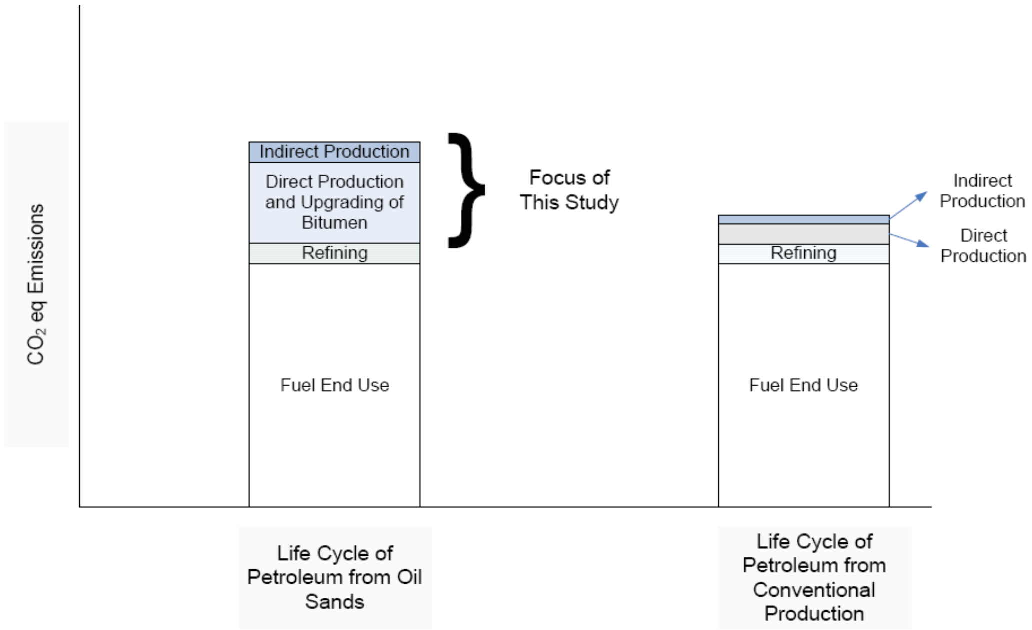
A follow up to the Oil Sands Technology Roadmap reviewed the long-term R&D opportunities for bitumen recovery technology. This study outlines and prioritizes research and development areas in terms of GHG emissions reduction potential and project costs versus potential payback. The study identified 42 programme areas with an estimated current investment of US$25 million that can lead to new technologies associated with the upgrading process. They also estimate that the greatest potential for GHG emissions reduction within the oil sands industry is in the extraction phase of the SAGD process. They estimate that with use of solvents in the recovery stage, up to 50 per cent of GHG emissions could be reduced. Efforts to reduce hydrogen consumption by various methods outlined in the report can result in an overall reduction of hydrogen requirements by 10 per cent. They estimate that there are few technologies on the horizon that will significantly reduce the GHG emissions from the mining and upgrading phases.

Source: ISEEE 2006

2.4.2 Lifecycle carbon footprint

The lifecycle carbon emissions from oil as a transport fuel take into account the carbon content of fuel and the refining process. Diesel is used as the benchmark as the most dominant transport fuel in the commercial and industrial sector. Please see Figure 2.7 below.

Figure 2.7: Lifecycle carbon emissions of conventional and unconventional oil



Source: ISEEE, 2006

Table 2.11 below summarises the life-cycle carbon emissions (transport application) from different categories of oil expressed in gCO_2/kWh in 2010, 2020 and 2030.

Table 2.11: Lifecycle carbon emissions from oil in 2010, 2020 and 2030 in gCO_2/kWh

Fuel	2010	2020	2030
Conventional oil	361	361	361
Unconventional oil	469	469	469

Source: IPCC

2.4.3 Supply and infrastructure vulnerability

The Whitegate refinery in Cork is the only one in Ireland. The refinery processes light, sweet crude, sourced primarily from the North Sea. The refinery has the ability to produce 18,000 barrels a day of gasoline, and 30,000 barrels a day of diesel and jet fuel (Wall Street Journal, 2007). As the risk of flooding is projected to increase in these areas then the refinery will be under potential risk too.

There is some likelihood that there will be some impact on the North Sea oil and gas operations as a result of climate change. Damage to infrastructure in this region will affect

Ireland as this is where much of the country's oil and gas are imported from. Increased wave action, storm surges, and coastal erosion may result in design changes to conventional offshore and coastal facilities. This may in turn increase the cost of pipeline construction because extensive trenching may be needed to combat the effects of coastal instability and erosion (especially that caused by permafrost melting (IPCC, 2001[26]).

There will be no impact on the availability of the resource due to climate change.

26 IPCC (2001) Contribution of Working Group II to the Third Assessment Report of the Intergovernmental Panel on Climate Change Impacts, Adaptation & Vulnerability

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The Irish Energy Tetralemma

Fuel Report 3: Natural Gas

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ Gas is positioned in the middle of the fossil fuels on the basis of fuel cost in both Ireland and internationally. It is cheaper than oil, but more expensive than coal and peat. ▪ There is no single world price for gas. Due to transportation issues conventional gas is typically traded on regional markets; however, the development of liquefied natural gas (LNG) has allowed gas to be traded over larger distances. Russia dominates both the global and European markets, although Ireland's current imports are entirely from the UK. ▪ Using an average of World Bank, US EIA[1], IEA[2], and EU[3], and BERR[4] real price forecasts, gas is predicted to remain relatively stable in its value in real terms: €5.64/GJ in 2010, €5.47/GJ in 2020, €5.88/GJ in 2030. ▪ Ireland currently has indigenous gas production off the South coast at Sevenheads and Kinsale and future production is expected off the West coast at the Corrib field. Despite these indigenous reserves, Ireland will continue to import the majority of its natural gas supply.
Delivered energy cost	▪ Gas is a relatively cheap source of energy in the energy mix in Ireland and internationally. Only coal and nuclear offer cheaper alternatives. ▪ As of early 2010 delivered cost of energy from gas (defined as the levelised cost of generation) is approximately €36-39/MWh – this is based on natural gas open cycle gas turbine (OGCT) technology. ▪ The future competitiveness of gas is likely to be based upon the more frequent use of natural gas combined cycle (NGCC) technology. This technology is already available and is not expected to have a major effect on the levelised cost of generation. Gas is therefore likely to remain very competitive. ▪ The market price of carbon dioxide can have a considerable impact on the competitiveness of gas-based generation (which is carbon-intensive). Carbon capture and storage (CCS) is seen as both an opportunity (to generate extra revenue) and cost (as it has a significant capital and operational cost). Ireland has a very good potential to deploy and operate CCS schemes. Developers would only invest in CCS if it is financially viable (a combination of

1 United States Energy Information Administration

2 International Energy Agency

3 European Union

4 UK Government Department for Business Enterprise and Regulation Reform

	appropriate carbon price and public sector funding) and therefore CCS have a broadly neutral effect on the delivered cost of energy from gas.
Policy & Regulation	▪ Gas, like other fossil fuels, is at a relative disadvantage to other fuels in terms of policy and regulatory barriers and the lack of particular incentives for its use. ▪ At the European level, a range of regulatory burdens exist to gas power generation including: EU Emissions Trading Scheme (EU ETS), EU Large Combustion Plant Directive and EU Integrated Pollution Prevention and Control Directive. ▪ The competitiveness of gas, in the context of policy and regulation, could improve if carbon capture and storage (CCS) is supported at the national and EU levels. The EU framework already aims to develop a number of strategic large-scale CCS facilities and the draft proposal for a EU Carbon Capture and Storage Directive will reinforce this, which Ireland can potentially benefit from.
Market context in Ireland	▪ Gas already plays a major role in Irish electricity generation and this is likely to remain the case. Two new Combined Cycle Gas Turbine (CCGT) plants were planned to open in south west Ireland in 2009. Taken with the probable closure of ESB's oil plants in the next few years and environmental restrictions on coal generation, this means that gas will likely be the most important fuel for new conventional generation capacity in Ireland.

Security of supply

Import dependence	▪ 91 per cent of gas used in Ireland is imported, which makes the country highly import dependent. ▪ Indigenous production is expected to increase in future years, which has the effect of lowering Ireland's gas import dependence. ▪ Conventional gas makes up approximately a quarter of the total primary energy requirement (TPER); however by 2020 and 2030 a significant proportion of this will be composed of LNG (once the new Shannon Estuary terminal is completed). ▪ Conventional gas' current weighted import dependence is 24 per cent and LNG's is 0 per cent. By 2030 gas' share of TPER is expected to slightly decrease and the balance between conventional gas and LNG should be more even at approximately 7 per cent for conventional gas and 13 per cent for LNG.
Fuel place of origin	▪ Although conventional gas is available from a large number of exporting countries, infrastructure limitations require Ireland to import from within Europe. Currently all Irish gas imports are from the UK, however this may change in the future as North Sea gas

	reserves run low. ▪ Ireland does not currently import any LNG; in the future there are likely to be a number of possible sources of LNG supply. The current major LNG producers include Gulf States such as Qatar and UAE, in addition to Malaysia, Indonesia and Australia.
Supply and infrastructure resilience	▪ The conventional gas supply and infrastructure resilience is relatively low. The supply chain is typically fragile and complex. The Irish natural gas network has received extensive investment in recent years having also been expanded with the Galway to Mayo pipeline. ▪ LNG is relatively more resilient. Its supply chain and infrastructure is much less fragile than conventional gas. It does require a regasification terminal though and until Ireland has one built, LNG will not be imported.
Market volatility	▪ Gas is closely linked to the oil markets in terms of its price, demand and availability at any point in time. Higher oil prices and supply deficits lead to an increased demand for gas. ▪ Gas may be susceptible to supply shocks due to the fragile and complex nature of its transportation infrastructure. However, given the increased market share of LNG, which fosters a greater number of potential exporters and relies on a more robust infrastructure, the market security of gas could increase over future years. ▪ Ireland is also in a favourable position of having an indigenous gas supply that could smooth-over any short term shocks.
Energy availability and intermittency	▪ Gas power plants have a capacity factor of approximately 57 per cent. ▪ Of the fossil fuels, gas is the most difficult to store.

Sustainability

Fuel longevity	▪ Best current global gas reserves-to-production ratio is estimated to be between 57 and 63 years. Combining the predicted levels of reserves with predicted rate of production suggests that the longevity of gas is declining. In 2010, approximately 51 years will remain, by 2020 this may be reduced to 33 years, and by 2030 just 21 years of gas may remain.
Environmental impacts	▪ Natural gas is a relatively non-polluting fuel. Air emissions occur at the generation stage of the life cycle of the fuel. Pollutants are also emitted from the construction and extractions stages although these are negligible. While there are potentials for negative impacts on the marine environment during extraction these are difficult to quantify as it depends heavily on the extent of accidents and the risks of these. Although the probability of these

	accidents happening is low, if they do occur there could be considerable damage to ocean life.

Climate change

Carbon content	▪ The IPCC provide the carbon content of natural gas at 56.1 tCO_2/TJ. This value is used both for natural gas as well as LNG.
Lifecycle carbon footprint	▪ Current gas fired power plants have cumulative emissions between 440 gCO_2eq/kWh and 780 gCO_2eq/kWh. Advanced and future gas-fired power plants are estimated to emit just under 400 gCO_2eq/kWh. ▪ The majority of carbon emissions (and other GHG emissions – expresses as CO_2 equivalent) from gas-fired power plants arise during the operation of the power plant and range between 360 gCO_2eq/kWh and 575 gCO_2eq/kWh for present technologies. ▪ Upstream emissions are not completely insignificant especially as there are considerable losses from long range pipeline transportation.
Supply and infrastructure vulnerability	▪ There are potentially some impacts to the pipeline infrastructure due to more extreme weather patterns. There are also potential impacts on the North Sea mining infrastructure in the same way as there is for oil. Severe weather conditions can affect the transportation of LNG.

3.1: Natural Gas: the basics

Natural gas is a fossil fuel consisting primarily of methane. It may also include significant quantities of heavier hydrocarbons such as ethane, propane, butane, or pentane, but these are typically removed prior to use as a consumer fuel. Natural gas may also contain carbon dioxide, nitrogen, helium and hydrogen sulfide. Natural gas deposits can be found in oil fields, isolated in natural gas fields, and in coal beds (as coalbed methane).

Natural gas is typically referred to as simply ‘gas’, especially when compared to other energy sources. Before natural gas can be used as a fuel, it must undergo extensive processing to remove almost all materials other than methane. The by-products of that processing, i.e. ethane, propane, butanes, pentanes, can also be used as sources of fuel.

Natural gas is a major source of electricity generation through the use of gas turbines and steam turbines. Natural gas burns cleaner than other fossil fuels, such as oil and coal, and produces less carbon dioxide per unit of energy released.

Liquefied natural gas (LNG) is natural gas that has been cooled to about minus 260 degrees Fahrenheit for shipment and/or storage as a liquid. The volume of the liquid is about 600 times smaller than the gaseous form. In this compact form, natural gas can be shipped in special tankers to receiving terminals. At these terminals, the LNG is returned to a gaseous form and transported by pipeline to distribution companies, industrial consumers, and power plants.

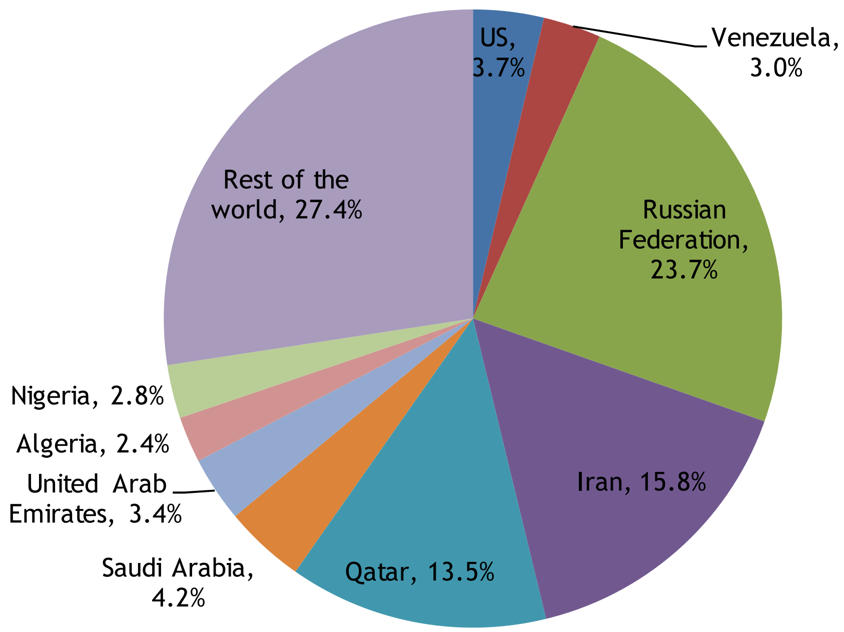
3.2: Natural gas as a commodity

3.2.1 Global Reserves

Historically, world natural gas reserves have generally trended upward. As of January 2008, proven world natural gas reserves as reported by Oil & Gas Journal, referenced in US EIA[5], were estimated at 175 trillion cubic metres — virtually unchanged from the estimate for 2007. In recent years reserves have remained relatively stable, despite growing demand for natural gas, implying that, to date, producers have been able to continue replenishing reserves successfully with new resources.

BP (2010) estimate 187 trillion cubic metres of proven global gas reserves. As Figure 3.1 shows, Russia (23.7 per cent) has the largest reserve followed by Iran (15.8 per cent), and Qatar (13.5 per cent).

Figure 3.1: Proven global gas reserves by country, 2009



Source: BP, 2010, Statistical Review of World Energy

According to the US EIA[6] the largest additions to natural gas reserve estimates in 2008 were reported for Venezuela and Saudi Arabia. Venezuela added an estimated 14 trillion cubic feet (a 9 per cent increase over 2007 proved reserves) and Saudi Arabia 13 trillion cubic feet (5 per cent). There were smaller, but still substantial, reported increases in reserves in Malaysia and Angola - both of which added around 8 trillion cubic feet. The reserve addition in Malaysia represents an 11 per cent increase in its proven reserves. The addition in Angola represents an increase of more than 300 per cent. The United States also had a fairly substantial 6 per cent increase in reserves, almost 7 trillion cubic feet over the 2007 estimate.

5 US Energy Information Administration, 2008, *International Energy Outlook 2008*, EIA

6 US Energy Information Administration, 2008, *International Energy Outlook 2008*, EIA

Global production of natural gas is expected to be 3.3 trillion cubic metres by 2010[7]. This represents a 14 per cent increase from 2005 levels. By 2030, gas production is due to reach 4.5 trillion cubic metres, a rise of over 55 per cent since 2005. India and China are expected to drive much of the projected growth. Similarly, the update of the EU European Energy and Transport Trends to 2030 forecasts global gas consumption to increase from 2,121 Mtoe in 2001 to 4,162 Mtoe in 2030. This represents a growth of 96 per cent over the three decades, see Table 3.1.

Table 3.1: Global gas consumption forecast to 2030

	2001	2010	2020	2030
EC DG TREN (Mtoe)	2,121	2,676	3,583	4,162
US EIA (trillion cubic metres)	-	3.3	4.0	4.5

Source: As stated in table

Worldwide, the reserves-to-production ratio is estimated to be between 57 years [8] and 63 years[9]. By region, the highest ratios are about 48 years for Central and South America, 78 years for Russia, 79 years for Africa, and more than 100 years for the Middle East. Table 3.2 below shows the different current estimates from a range of sources.

Table 3.2: Gas reserves-to-production ratio

	BP	WEC	US EIA	Average
Years remaining	60	57	63	60

Source: As stated in table

There is no readily available information on future estimates for global reserves. The actual figures are highly dependent on estimated future production forecasts. Therefore, for the purposes of this study, we have combined the current projections for gas production with the current level of global reserves (see Table 3.3 below). Similar values are used for natural gas and LNG.

7 US Energy Information Administration, 2008, *International Energy Outlook 2008*, EIA

8 World Energy Council, 2007

9 US Energy Information Administration, 2008, *International Energy Outlook 2008*, EIA

Table 3.3: Forecast gas reserves 2010, 2020, 2030

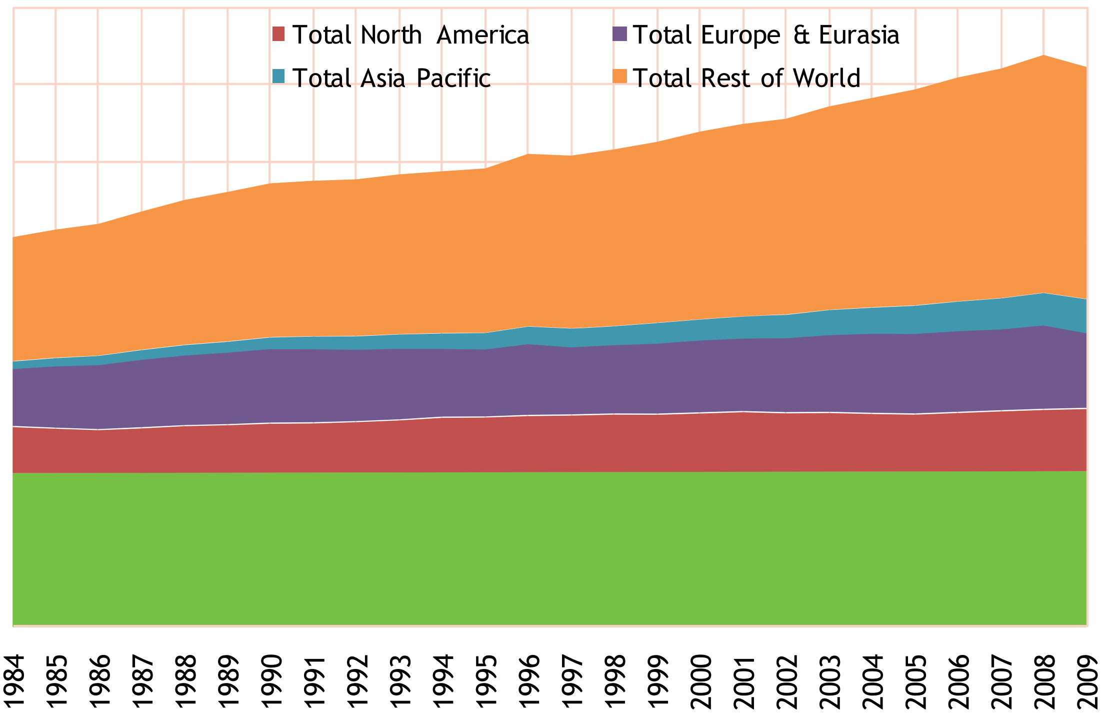
	Production (Tril. Cubic feet)	Reserves (Tril. Cubic feet)	Years remaining
2007	103.8	6186	60
2010	116.2	5875	51
2020	141.2	4713	33
2030	158.6	3301	21

Source: US EIA, BP, WEC

3.2.2 Global production and trade

In 2009, 2,987 billion cubic metres of natural gas were produced (BP 2010), see Figure 3.2. This represented a 2.1 per cent growth on the preceding year. North American production was strong, particularly in the USA. Notably, EU output dropped by 9.9 per cent.

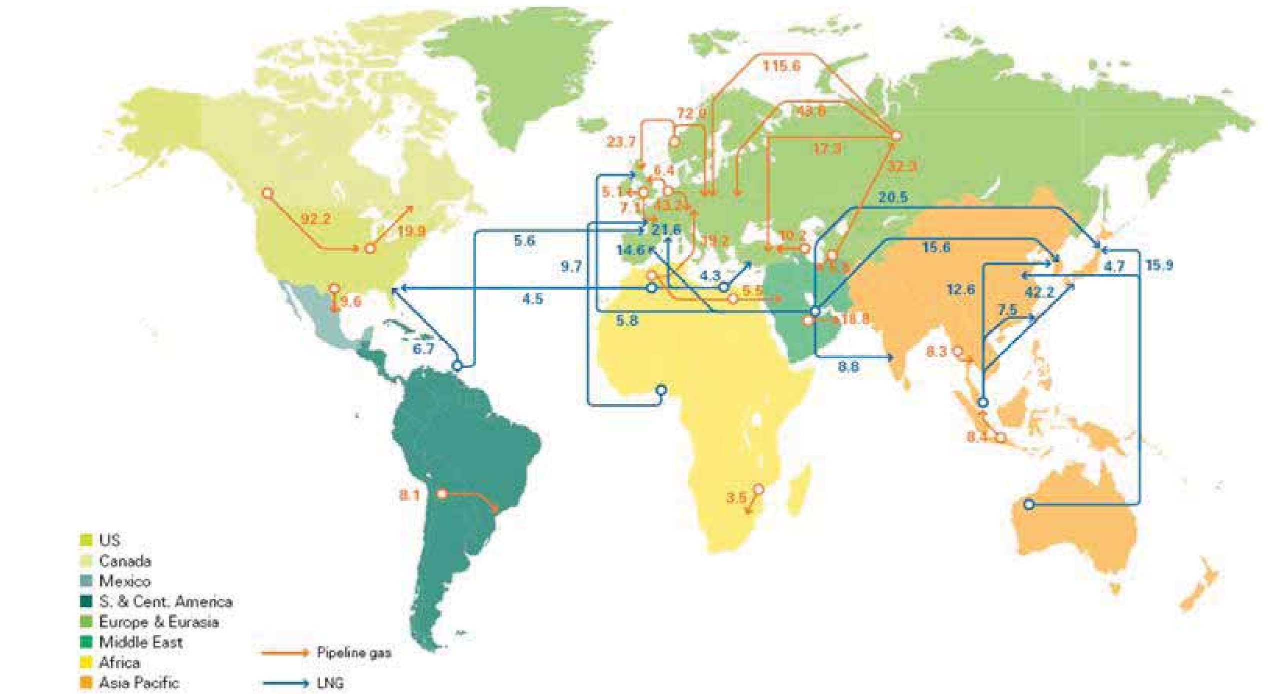
Figure 3.2: Global natural gas production by region, 2009 (billion cubic metres)



Source: BP (2010)

As Figure 3.3 below shows, Russia is the largest exporter of gas by pipeline with 115.6 billion cubic metres of natural gas to Western Europe excluding Turkey and 45 billion cubic metres to the FSU. Canada exports 92.2 billion cubic metres of natural gas to the US. The US is the largest importer with 105.8 billion cubic metres followed by Germany 88.82 and Italy 69.3 billion cubic metres. The trade flows for LNG show that the Middle East exports 20.5 billion cubic metres of LNG to Japan. Algeria Libya and Egypt export 21.6 billion cubic metres to Western Europe excluding the UK. Indonesia, Malaysia and Brunei export 42.2 billion cubic metres to Japan. Japan is the largest importer with 85.9 billion cubic metres followed by South Korea 34.33 billion cubic metres and Spain 27.01 billion cubic metres. (BP,2010)

Figure 3.3: Natural gas trade flows worldwide, 2009 (billion cubic metres)



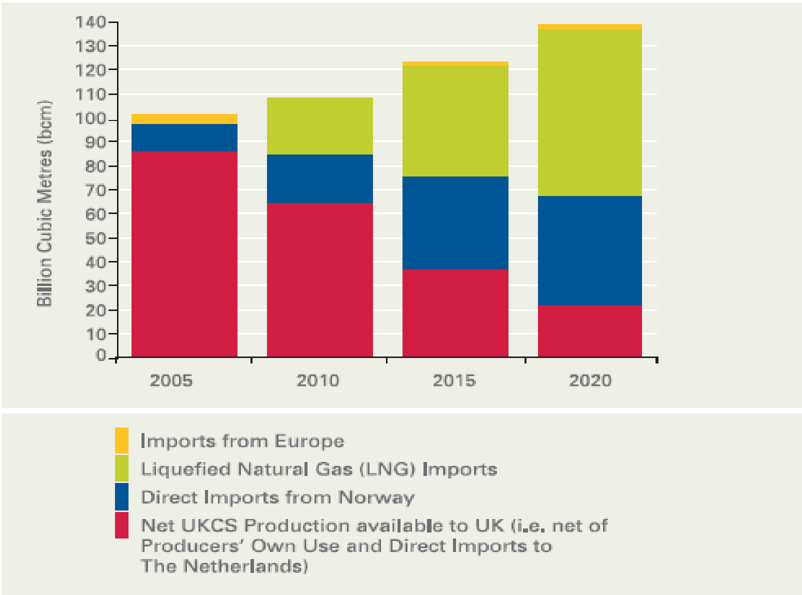
Source: BP (2010)

Natural gas trade is restricted by the practicalities of transporting low density gaseous fuels. Whilst pipelines are economical they are impractical across major oceans. As a consequence, most gas pipelines must supply relatively close geographic localities. The development of LNG is partly overcoming these traditional restrictions in the global natural gas trade.

All of Ireland’s current gas imports are from the North Sea, predominantly from UK sources. Given the reliance on gas imported from the UK it is useful to understand from where UK sources its own gas. As noted by O’Mahoney (2007), while the UK still has significant reserves of gas, it is now estimated that just over half of the UK’s gas reserves have been produced, meaning that the UK will also become increasingly dependent on imports, predominantly from Norway (expected to provide around a third of UK supplies by 2020), continental Europe and through the development of a UK LNG market (UK POST 2004) (see Figure 3.4 below).

In the medium to long term, Russia is expected to play a crucial role in the pipeline gas supply to most of Europe. On the one hand this will improve the fuel availability (on the basis of diminishing North Sea reserves) but, on the other hand, will lower the security given Russia's recent and likely future political objectives. LNG can be supplied to Ireland from a number of countries with over time is likely to prove more secure, in terms of market flexibility and diversity, than pipeline natural gas.

Figure 3.4: Possible UK future gas supply



Source: O'Mahoney, 2007

Recognising the importance of gas to Ireland's energy balance the Irish Government included the strategic goal to 'ensure the reliability and security of gas supplies' in their 2007 energy policy framework document. In the short-term, supplies seem relatively secure but the Government have proposed a number of actions aimed at improving the long-term position. In terms of risk, Ireland's current North Sea gas imports are relatively low-risk. As Table 3.4 shows, the UK scores favourably in all categories used in this analysis: OECD country risk classification, World Bank Ease of Doing Business Index, and World Bank Governance Indicators.

Table 3.4: Country Risk, Ease of Doing Business and Governance indicators

	OECD Country Risk Classification 2008 (score from 0-7, higher figure equals higher risk)	World Bank Ease of Doing Business index 2008 (rank of 178 countries)	World Bank Governance Indicators (average score)
UK	0	6	1.6

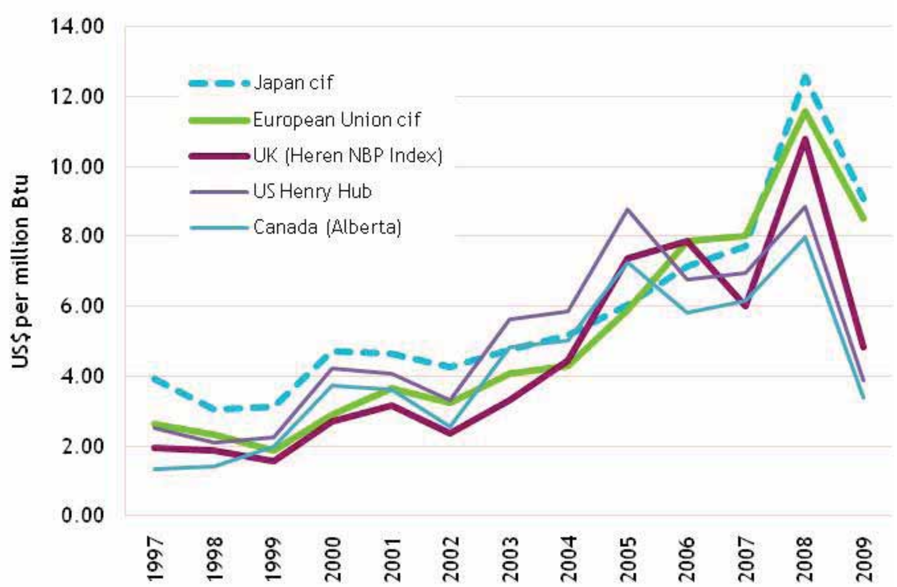
Source: OECD and World Bank 2008. Note: The OECD figure measures the country credit risk, i.e. the likelihood that a country will service its external debt. The World Bank Ease of Doing Business Index measures regulations directly affecting businesses and protections of property rights. The World Bank Governance Indicators are normally distributed with a mean of zero and almost all values lying between -2.5 and 2.5. The score here is an average of Political Stability, Government Effectiveness, Regulatory Quality, Rule of Law and Control of Corruption.

There is no readily available information on future estimates for country risks and political stability. Therefore, for the purposes of this study the current World Bank and OECD indicators are used. The methodology, however, takes into account the possible future mix of countries that will comprise the main gas exporters (on the basis of proven reserves and current willingness to export).

3.2.3 Gas Prices and Markets

Figure 3.5 shows the recent gas price trends in the major gas markets. It is evident that prices in both Europe and North America follow very similar trends. Included within the figure is the Japanese market price of LNG.

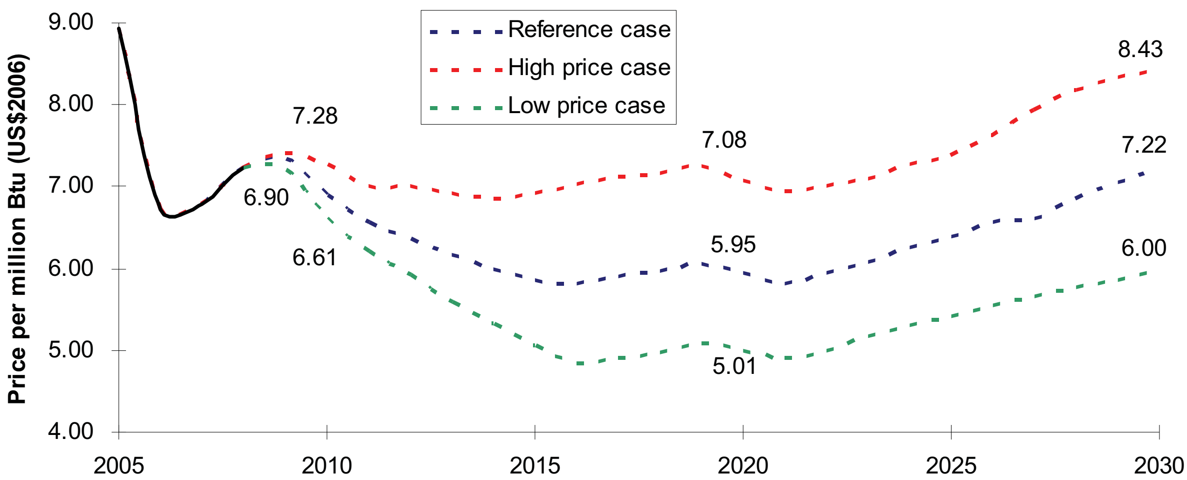
Figure 3.5: Recent gas prices per million Btu (nominal)



Source: BP (2010). Note: cif = cost + insurance + freight

The US EIA's National Energy Modelling System presents projections and analysis of the US Henry Hub gas price to 2030. The 'reference case' forecast assumes that current policies affecting the energy sector remain unchanged throughout the projection period. The reference case provides a clear basis against which alternative cases and policies can be compared. A high-price scenario and a low price scenario are presented along side the reference case (see Figure 3.6 below).

Figure 3.6: Real Henry Hub gas prices forecasts in three scenarios (2006US$/MBtu)



Source: US EIA (2008b)

World Bank commodity price data show average world prices for European natural gas. In 2007 the average price was US$7.40/MBtu. World Bank forecasts expect the price to rise to US$8.70/MBtu in 2010 but then fall back to US$7.10/MBtu by 2020.

The 2007 update of the EU European Energy and Transport Trends to 2030 forecasts gas price rises to be linked with oil price rises. It is evident from Table 3.5 below that the competitiveness of gas vis-à-vis coal is expected to decrease steadily: the gas to coal price ratio increases from 2.3 in 2005 to 3.2 in 2030. This could be an important factor in future investment choices for power generation.

Table 3.5: EU forecast fossil fuel prices to 2030

US$(2005)/boe[10]	2005	2010	2015	2020	2025	2030
Oil	54.5	54.5	57.9	61.1	62.3	62.8
Gas	**34.6**	**41.5**	**43.4**	**46**	**47.2**	**47.6**
Coal	14.8	13.7	14.3	14.7	14.8	14.9

Source: EC (2007b) European Energy and Transport Trends to 2030. Note: Assumed dollar exchange value equal to 1.25 $/€

10 Barrels of oil equivalent

The International Energy Agency's World Energy Outlook for 2007 expects the real price of European gas (using 2006 US$) to fall from US$7.31/MBtu in 2006 to US$6.60/MBtu in 2010. The trend is then a steady price rise to US$6.63/MBtu in 2015 and US$7.33/MBtu in 2030.

In summary Table 3.6 below shows the range of projected pipeline gas prices in 2010, 2020 and 2030 from a range of reference sources.

Table 3.6: Projected gas prices in 2010, 2020 and 2030 in US$ per million Btu

Source	2010	2020	2030
IEA	6.60	-	7.33
World Bank	8.70	7.10	-
US EIA (reference case)	6.90	5.95	7.22
BERR (central scenario)	6.40	6.90	7.20
European Commission	6.90	7.60	7.90

Source: as shown in the first column

Table 3.7 below summarises the range of projected LNG prices in 2010, 2020 and 2030 from a range of reference sources in €/GJ.

Table 3.7: Projected gas prices in 2010, 2020 and 2030 in €/GJ for LNG

Source	2010	2020	2030
IEA (Japanese imports)	5.82	5.83	6.23
BERR (UK price central scenario)	5.09	3.55	3.20

Source: as shown in the first column. Note: both estimates used for 2020 are actually for 2015 in the reference sources, and the BERR figure for 2030 is their estimate for 2025.

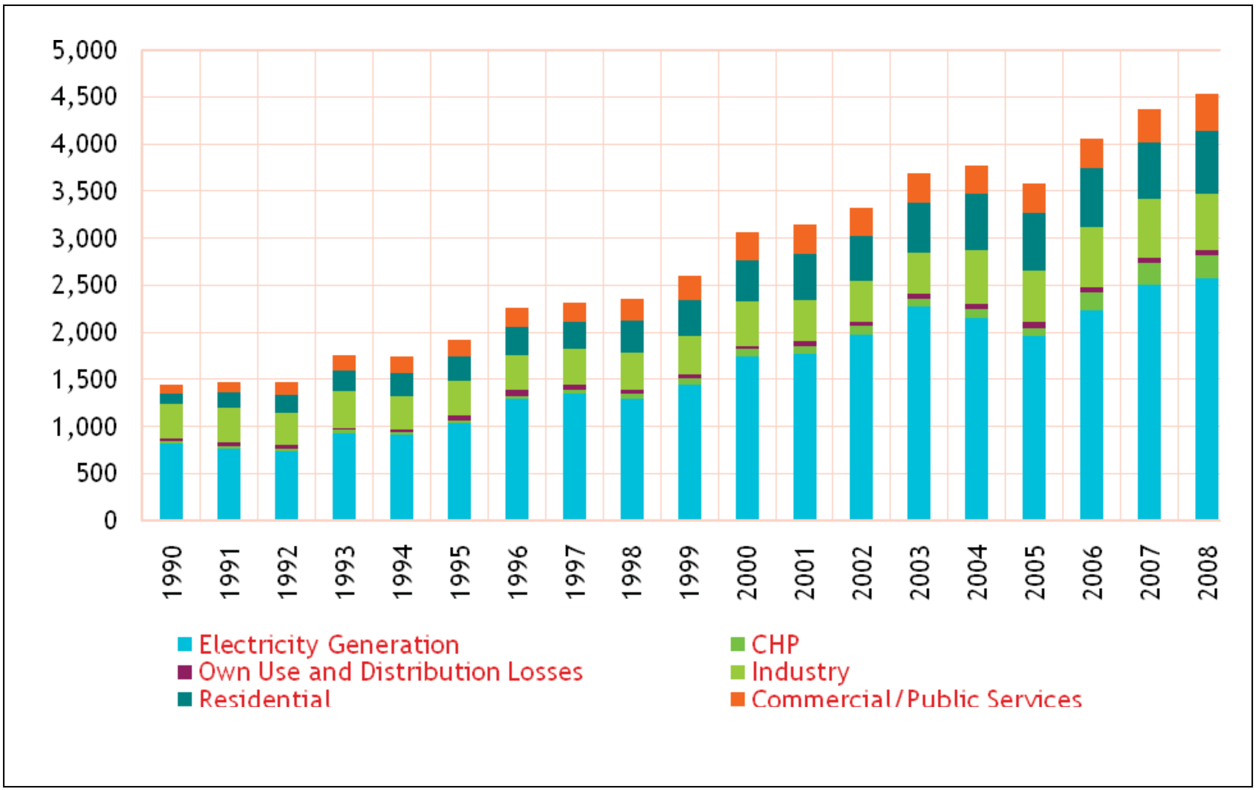
3.2.4 Weighted import dependence

In 2007, natural gas accounted for nearly 27 per cent of the Total Primary Energy Requirement (TPER) of Ireland[11]. Approximately 64 per cent of gas used in Ireland goes into electricity production with the remainder being used directly in commerce and industry (23

11 SEI, 2007, *Provisional Energy Balance*

per cent) or for domestic heating (14 per cent). A summary of gas demand in Ireland is shown in Figure 3.7 below.

Figure 3.7: Gas demand at a sectoral level in Ireland 1990 - 2008



Source: SEI[12]

At the end of March 2006, the supply arm of Bord Gáis retained less than 40 per cent market share of the gas supplied in Ireland. The remaining volume was either supplied independently or, in the case of large electricity generators, purchased directly by the parties themselves. Tariffs charged by BGS are approved by the Commission for Energy Regulation, whilst all other suppliers set unregulated tariffs.

Over 91 per cent of Ireland's natural gas (3,924 ktoe[13]) is imported into the country[14]. Almost all of these imports are from the UK. Ireland's indigenous natural gas production is at the Seven Heads and Kinsale fields off the south coast of Ireland. Although this is expected to decline over the next few years, new indigenous production is expected from the Corrib field, located off the West Coast of Ireland. The Corrib field will be operated by Shell and is owned by a consortium including Shell, Statoil and Marathon Petroleum. Reserves are believed to be of the order of 20-30bcm[15]/[16]. The development of the field was substantially delayed by

12 Sustainable Energy Authority of Ireland, 2010

13 Thousands of tonnes of oil equivalent

14 SEI, 2007, *Provisional Energy Balance*

15 Billion cubic meters

planning permission difficulties and the start date for deliveries is now expected to be in 2009/10.

Table 3.8 below summarises the sub-indicators that comprise the weighted import dependence indicator for gas in Ireland over the three timescales - 2010, 2020 and 2030. The 'share of the fuel mix' figures for LNG are based on the expected supplies from the future Shannon Estuary LNG terminal[17]. All figures for 2030 are calculated by applying SEI's projection for growth between 2010 and 2020 through to 2030.

Table 3.8: Projected share of fuel mix and import dependence for gas in 2010, 2020 and 2030 in per cent

	Conventional Gas			LNG		
Share of the fuel mix	27%	14%	9%	0%	10%	13%
Import dependence	91.%	78%	78%	100%	100%	100%
Weighted import dependence	**24%**	**11%**	**7%**	**0%**	**10%**	**13%**
Sub-indicators	**2010**	**2020**	**2030**	**2010**	**2020**	**2030**
Share of the fuel mix	27%	14%	9%	0%	10%	13%
Import dependence	91.%	78%	78%	100%	100%	100%
Weighted import dependence	**24%**	**11%**	**7%**	**0%**	**10%**	**13%**

Source: SQW Energy based on literature review

16 Bord Gáis website: http://www.bordgais.ie/corporate/index.jsp?1nID=93&2nID=97&3nID=354&4nID=354&5nID=354&6nID=354&7nID=354&8nID=354&pID=354&nID=364

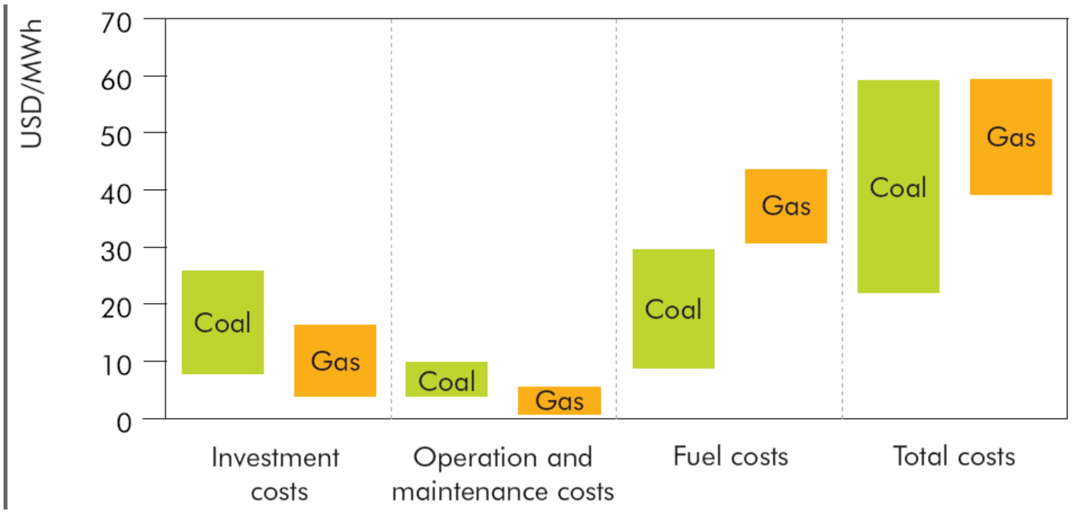
17 CER, 2008a, *Gas Capacity Statement 2008*

3.3: Natural gas in the energy system

3.3.1 Delivered energy cost

The IEA suggests that the current cost of delivered energy from gas-fired plants, including capital investment, operation and maintenance (O&M) and fuel costs, ranges between US$40 and US$60 per megawatt-hour (MWh) of electricity [18](Figure 3.8). This largely depends on the type and age of conversion technology used and the medium value is around US$50/MWh (€38/MWh).

Figure 3.8: Delivered energy costs from coal and gas-fired plant



Source: IEA 2008[19]

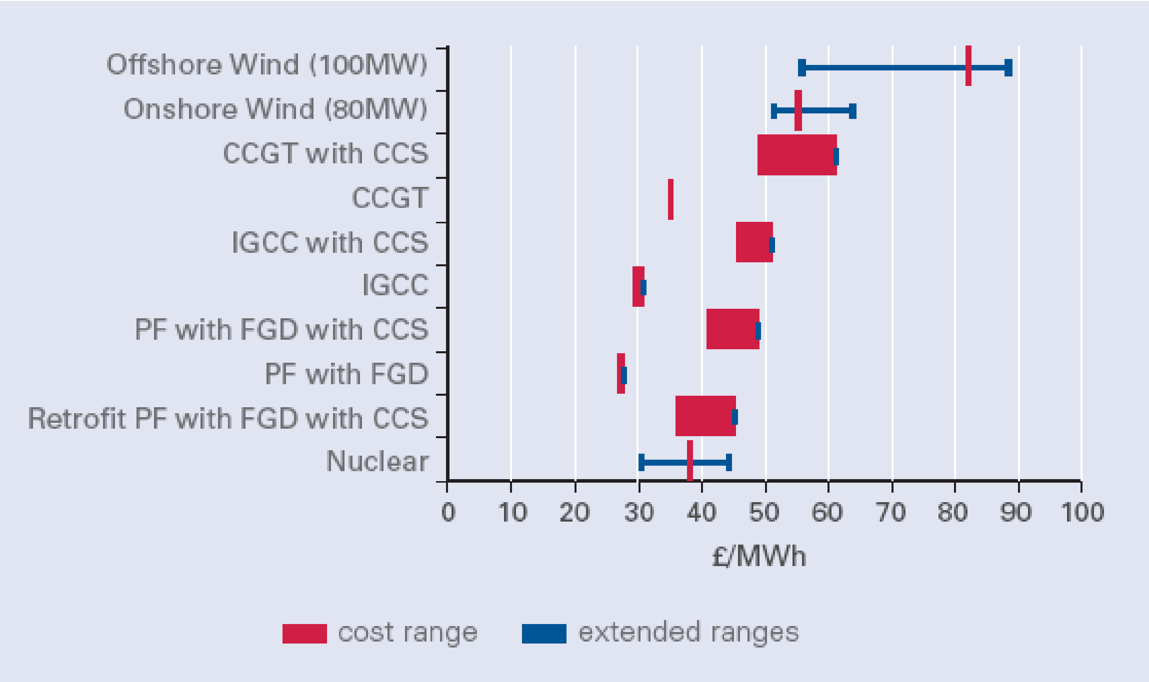
The UK's Department for Business Enterprise and Regulatory Reform (BERR) undertook modelling of the relative electricity generating costs of different technologies as part of the 2006 Energy Review. The modelling is based on levelised costs and provides estimates of the relative cost of electricity generation technologies under different scenarios and assumptions. The scenarios considered in the modelling include a base case, varying assumptions for gas and carbon prices, and a full range of sensitivities including discount rate, capital cost, O&M costs, fuel prices, carbon prices, and load factors.

Figure 3.9 below shows the results of the base case assuming central gas prices and no carbon price. The cost of electricity at a combined cycle gasification turbine power plant was estimated to be in the region of £35/MWh (€44/MWh) (BERR 2006).

18 IEA, *Energy Technology Perspectives Scenarios and Strategies to 2050*

19 IEA, *Energy Technology Perspectives Scenarios and Strategies to 2050*

Figure 3.9: Electricity generating costs of different technologies



Source: BERR (2006) Energy Review 'The Energy Challenge'. Note: CCGT – combined cycle gas turbine, CCS – carbon capture and storage, IGCC – integrated gasification combined cycle, PF – pulverised fuel (coal), FGD – flue gas desulphurisation.

The UK Energy Research Centre (UKERC) undertook a review of the literature on electricity generation levelised unit cost estimates. In total 145 documents were reviewed so that average cost estimates could be produced. As is evident from Table 3.9 below, the review found gas to be the cheapest fuel for electricity generation.

Table 3.9: Electricity generation levelised unit cost estimates, £/MWh

	Coal	Gas	Nuclear	Wind	Wind (offshore)
Mean	32.9	**31.2**	32.2	39.3	48.0
Median	31.9	**30.5**	31.3	35.9	47.9
Inter-quartile range	13.1	**9.5**	16.5	24.2	33.6
Standard deviation	9.7	**8.9**	10.5	16.6	20.0

Source: UKERC (2006, updated May 2007), A Review of Electricity Unit Cost Estimates

Other cost estimates have been produced by the Royal Academy of Engineering study undertaken by PB Power (2005) estimated the cost of electricity to be approximately £31/MWh (€39/MWh).

3.3.2 Natural gas – Conversion Technologies

The efficiency of natural gas-fired generation can be improved considerably through replacing gas fired steam cycles with more efficient natural gas combined-cycle (NGCC) plants, which consist of a gas turbine and a steam cycle. The combined cycle technology recycles waste heat from the gas turbine to produce steam to power the steam turbine. Efficiencies of the best available combined-cycle plants are around 60 per cent. The new Siemens-E.ON NGCC plant under construction in Germany is expected to be the first to break the 60 per cent barrier[20].

The IEA[21] expect future research and development to focus on natural gas turbine design and additional efficiency improvements. Gas turbine development will be aimed at higher firing temperatures and the use of reheat, which gives higher power outputs and efficiencies, but which may increase the formation of some pollutants. Other activities are likely to be focused on advanced combustors, improving the aerodynamic efficiency of components and improving blade cooling mechanisms.

Carbon capture and storage (CCS) is another emerging technology that is pertinent to gas. The aims and theoretical potential of CCS is to remove and store up to 85 per cent of carbon emissions, thus making fossil fuel-fired plants significantly cleaner. CCS is still at an early R&D and demonstration stage and it is also associated with rather high capital costs. The latter could potentially render some plants uneconomic to operate, especially in a retrofit situation.

There are political initiatives towards making CCS mandatory for new-build power plants especially in the EU and a draft European Directive has been circulated for consultation. Both at the demonstration and deployment stages of CCS it is expected that the technology will be cost neutral (life-cycle). This will be achieved through three main revenue mechanisms: (1) revenue from enhanced oil recovery; (2) revenue from carbon emissions trading; and (3) public sector grants and subsidies to fill any potential funding gaps that may jeopardise the deployment of CCS. Therefore, regarding total delivered energy cost from gas, future price estimates assume no cost impact from applying CCS.

Future delivered energy prices from gas combustion are not readily available. To estimate the levelised price of electricity generation, the best available technology (BAT) expected to be fully commercialised (i.e. that can be considered as mainstream) was used as the benchmark. Thus, the following technologies were takes as the benchmarks for each of the three time horizons:

- 2010 - the currently available open cycle gas turbine (OGCT) technology.
- 2020 – natural gas combined cycle (NGCC) technology.
- 2030 – natural gas combined cycle (NGCC) technology.

20 IEA, *Energy Technology Perspectives Scenarios and Strategies to 2050*

21 IEA, *Energy Technology Perspectives Scenarios and Strategies to 2050*

Table 3.10 below summarises the range of projected delivered energy prices in 2010, 2020 and 2030 from a range of reference sources. The prices are presented in €/GJ.

Table 3.10: Projected delivered energy prices (from gas) in 2010, 2020 and 2030 in €/GJ

Source	2010*	2020	2030
IEA	10.5	-	-
UK BERR	-	12.2	12.2
UKERC	10.8	-	-
Royal Academy of Engineering	10.8	7.8	7.8
NEA	10.0	-	-
Stern (UK HM Treasury)	-	12.5	12.5

Source: as shown in the first column

* these are typically the values for current prices as 2010 forecasts were not readily available

3.3.3 Policy and regulation

Natural gas is considered the cleanest of all the fossil fuels and its use, particularly for power generation is enabled in most developed countries, including Ireland, through relatively standardised and short planning and development procedures. Nevertheless, the use of natural gas is regulated to limit the pollution resulting from its combustion. The principle regulations affecting the use of natural gas include:

- EU Emissions Trading Scheme aims to increase the marginal cost of carbonaceous fuel use through establishing a price for carbon emissions. The ETS scheme has covered the power generation sector since its inception. When burned, gas emits higher levels of carbon dioxide than any other fossil fuel. Natural gas burns cleaner than other fossil fuels, such as oil and coal, and provides less carbon dioxide per unit of energy released.
- A series of EU directives on ambient air quality limit values and thresholds for particular pollutants. Those included are nitrogen oxides, sulphur dioxide, lead and particulates, benzene and carbon monoxide.
- The Integrated Pollution Prevention and Control Directive (IPPC) imposes a requirement for industrial and agricultural activities with a high pollution potential to have a permit which can only be issued if certain 'Best Available Techniques' are met. The companies themselves bear responsibility for preventing and reducing any pollution they may cause, effectively enforcing minimum standards for polluting industries.

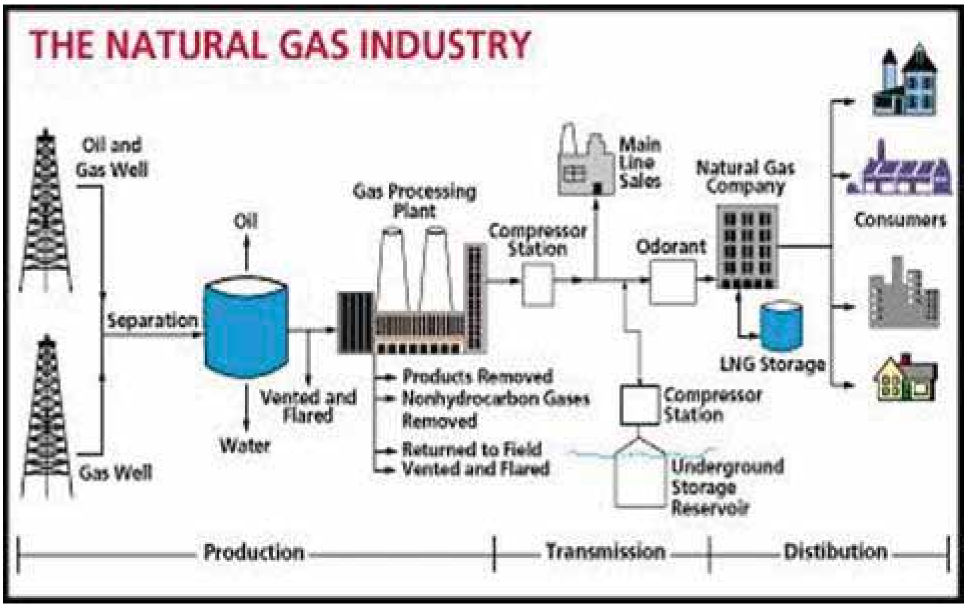
No particular, direct incentives associated with using gas as a fuel were identified, however the policy and regulatory regime in Ireland is favourable to developing new natural gas capacity.

3.3.4 Supply chain and infrastructure resilience

Conventional gas

The movement of natural gas from producers to consumers requires an extensive and elaborate transportation system. In many instances, natural gas produced from a particular well will have to travel a great distance to reach its point of use. Typically, the transportation system for natural gas consists of a complex network of pipelines, see Figure 3.10.

Figure 3.10: Natural gas supply chain



Source: www.energysolver.com

Once a well is operational, the natural gas must be moved to the first step in the transportation process. In most instances, a producing well is part of a larger producing field that consists of many, sometimes hundreds, of producing wells. A complex gathering system can consist of thousands of miles of pipes, interconnecting a processing plant with as many as 100 wells in an area. Using a common processing plant rather than one for each well is the most economical way to process gas.

Whatever the source of the natural gas, it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen, and other compounds that must be removed before it can be transported and used by the consumer as “pipeline quality” dry natural gas.

After being processed the natural gas must then travel to the consumption region. This maybe via underwater gas pipelines, such as those which link Norwegian gas fields to European terminals, or overland gas pipelines like those that bring Russian gas to the European Union. These gas pipelines are usually buried underground and with the aid of compression plants positioned at regular intervals along the network, the compressed gas circulates at high speed through the gas pipeline.

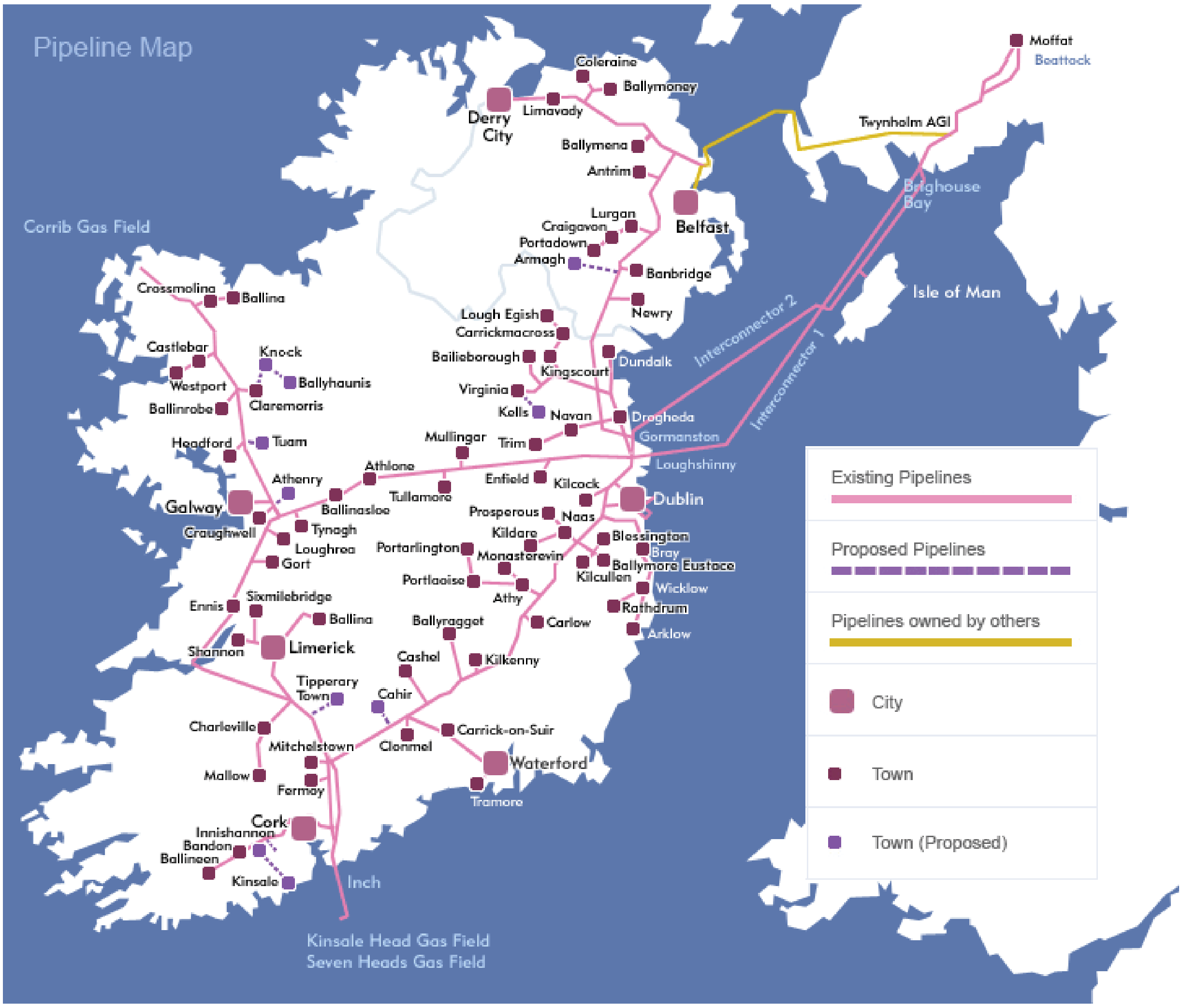
Distribution is the final step in delivering natural gas to end users. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines, most other users receive natural gas from a local distribution company. Typically, local distribution companies take ownership of the natural gas at their interconnection points on the high capacity pipelines and then deliver it to each individual customer's location of use. This requires an extensive network of small-diameter distribution pipes.

The natural gas network in Ireland is operated by Bord Gáis Éireann (BGÉ), a commercial state body. The high pressure transmission network conveys gas from two entry points (at Inch and Moffat) to directly connected customers and distribution networks throughout Ireland, as well as to connected systems at exit points in Scotland (the Scotland-Northern Ireland Pipeline) and the Isle of Man.

Considerable investment has occurred in the natural gas network in recent years. A total of €1.53 billion was invested in the period 2001 to 2005 and a further €1.7 billion is scheduled for investment by 2013[22]. The network has recently been expanded with the development of the Galway to Mayo pipeline. This will link the Corrib gas field to the Irish market. In addition BGÉ has completed the South/North Pipeline, linking the Irish and Northern Irish markets. A map of the gas distribution network on the island of Ireland is shown in Figure 3.11 below.

22 SEI, 2007, *Security of Supply in Ireland, 2007*

Figure 3.11: Natural gas network on the Island of Ireland (as at 2nd July 2010)



Source: CER 2010

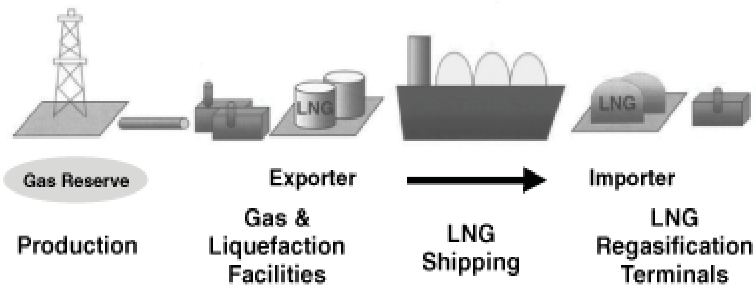
LNG transportation

LNG has an inherent lower fragility in the transportation process, compared to conventional natural gas, which is fundamental to its continuing production and use. Since LNG occupies only a fraction (1/600) of the volume of natural gas, and takes up less space, it is more economical to transport across large distances and can be stored in larger quantities. The LNG supply chain has four important steps: (1) Exploration and Production, (2) Liquefaction, (3) Shipping, and (4) Storage and Regasification.

Once natural gas is transported from the well, it can be fed into a LNG plant to remove water, hydrogen sulfide, carbon dioxide and other components that will freeze (e.g., benzene) under the low temperatures needed for LNG storage. Each LNG plant consists of one or more ‘trains’, with a typical train consisting of a compression area, propane condenser area, methane and ethane areas.

Once the gas has completed its way through the train, the newly produced LNG can be loaded on to ships for world wide distribution. It must then be delivered to a regasification terminal, where the LNG is reheated and turned back into gaseous form. Regasification terminals are usually connected to a storage and pipeline distribution network to distribute natural gas.

Figure 3.12: The LNG supply chain



Source: http://content.edgar-online.com/edgar_conv_img/2005/04/21/0000945234-05-000284_O1638701638703.GIF

When LNG is received at most terminals, it is transferred to insulated storage tanks that are built to specifically hold LNG. These tanks can be found above or below ground and keep the liquid at a low temperature to minimize the amount of evaporation. If LNG vapors are not released, the pressure and temperature within the tank will continue to rise. LNG is characterized as a 'cryogen' - a liquefied gas kept in its liquid state at very low temperatures. The temperature within the tank will remain constant if the pressure is kept constant by allowing the boil-off gas to escape from the tank. This is known as auto-refrigeration. The boil-off gas is collected and used as a fuel source in the facility or sometimes on the tanker transporting it. When natural gas is needed, the LNG is warmed to a point where it converts back to its gaseous state. This is accomplished using a regasification process involving heat exchangers.

Planning permission has been secured for the construction of a LNG terminal in the Shannon Estuary. The current proposals suggest that the terminal will be in operation by the winter of 2012/13[23]. The proposed terminal would be connected to the existing transmission system by circa 26km of pipeline. Shannon LNG supply is likely to be around 9 million cubic metres per day in 2012/13, increasing to almost 16 million cubic metres per day in 2014/15.

3.3.5 Market context in Ireland

Opening of the full natural gas Irish retail market took place in July 2007 (all non-domestic customers have been free to choose their supplier since 2004). Bord Gàis Energy is the incumbent gas company with new independent operators including Vayu and Flogas.

Two new Combined Cycle Gas Turbine plants were planned to open in south west Ireland in 2009 and the probable closure of ESB's oil plants in the next few years and environmental

23 CER, 2008, *Gas Capacity Statement 2008*

restrictions on coal generation, mean that gas will likely be the most important fuel for new conventional generation capacity in Ireland.

Considerable investment has occurred in the natural gas network in recent years and the network has recently been expanded with the development of the Galway to Mayo pipeline. This will link the Corrib gas field to the Irish market. In addition BGÉ has completed the South/North Pipeline, linking the Irish and Northern Irish markets. As mentioned previously, an Irish LNG terminal is due to be in operation by 2012/13 and will be connected to the existing gas transmission infrastructure.

3.3.6 Market volatility

Although gas is the least abundant fossil fuel, it is available world-wide and there exists a large number of export countries. As a commodity, gas may be susceptible to supply shocks due to the fragile and complex nature of it transportation infrastructure. However, given the increased market share of LNG, which fosters a greater number of potential exporters and relies on a more robust infrastructure, the market security of could increase over future years. Ireland is also in a favourable position of having an indigenous gas supply that could smooth-over any short term shocks.

3.3.7 Environmental impacts

The major burdens of the gas fuel cycle are the atmospheric emissions of pollutants, arising mostly from the power generation stage, although some emissions are also present in the extraction and transport stages. The upstream stages are found to be significant if the gas is sourced from countries where pipeline technology is not state of the art. For instance, the ExternE methodology for calculating environmental externalities (1998) found that on a national level, Russian pipelines were not state of the art and had a larger impact, whereas Algeria, which had recently refurbished their pipelines had a much smaller impact.

The pollutants emitted are NO_x, CO, CH_4, and CO_2. SO_2 emissions are negligible, given the very small content of SO_2 in the natural gas. The effects of liquid effluents and solid wastes are not quantifiable yet, although they are expected not to be highly significant compared to the rest.

The effect of exploration, drilling, and gas production activities on the marine environment could be quite significant but difficult to determine.

Table 3.11 below summarises the level of environmental impacts (externalities) expressed as Euros per mega-watt of power generated (€/MWh) over the three timescales - 2010, 2020 and 2030. Given that only current externality costs are reported in the literature, this study assumes that these costs will remain the same in real terms over the timescale discussed.

Table 3.11: Environmental Impact of gas - externality cost - in 2010, 2020 and 2030 in €/MWh

	2010	2020	2030
Natural gas	25	25	25
LNG	25	25	25

Source: ExternE, 1998, *Externalities of Energy*, European Commission

3.4: Natural gas and climate change

3.4.1 Carbon content of fuel

The IPCC provide the carbon content of natural gas at 56.1 tCO_2/TJ. This value is used for both natural gas and LNG. The carbon content remains the same for both types of fuel for 2010, 2020 and 2030.

Table 3.12: Carbon content of natural gas in 2010, 2020 and 2030 in tCO_2/TJ

Source	2010	2020	2030
Natural gas	56.1	56.1	56.1
LNG	56.1	56.1	56.1

Source: IPCC

3.4.2 Lifecycle carbon footprint

The majority of carbon emissions (and other GHG emissions – expresses as CO_2 equivalent) from gas-fired power plants arise during the operation of the power plant and range between 360 gCO_2eq/kWh and 575 gCO_2eq/kWh for present technologies. No significant emissions arise during the construction and decommissioning of the power plant[24].

Upstream emissions are not completely insignificant especially when there are considerable losses from long range pipeline transportation. For instance, approximately 0.2 per cent of North Sea gas is lost from leakages (Dones, 1998) and in the US nearly 10 per cent of natural gas is lost before reaching the power plant. Most of this energy loss is due to the compression of natural gas for transport via pipeline. Transmission operations also lose gas due to leaks from compressor stations, metering and regulating stations, and pneumatic devices. For Ireland, this will be an important source of GHG emissions as indigenous supply is limited.

Current gas fired power plants have cumulative emissions between 440 gCO_2eq/kWh and 780 gCO_2eq/kWh. Advanced and future gas-fired power plants are estimated to emit just under 400 gCO_2eq/kWh over the full life-cycle with approximately 50gCO_2eq/kWh as non-direct GHG emissions. In order to realise these lower emissions, efforts need to focus on the reduction of gas leakage, improvements of power plant combustion performance and overall plant efficiency as well as pipeline performance. It is assumed that gas fired plants in 2020 will be constructed to these specifications.

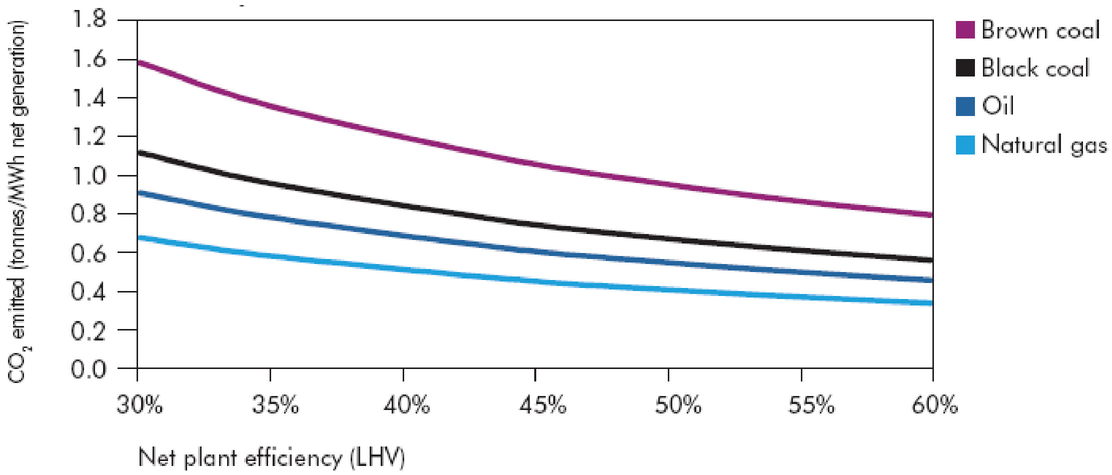
There is a lot of scope to increase the efficiency of gas-fired plants primarily by replacing steam plants with combined cycle plants. In fact, between 1992 and 2005 the efficiency of gas-fired plants increased from 35 per cent to 42 per cent, with most of the gains in efficiency attributed to the introduction of combined cycle plants. Higher efficiencies may even be realized with natural gas combined cycle (NGCC) plants where efficiencies can top 60

24 International Atomic Energy Agency (IAEA), 2006, *A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies*, In Planning and Economics Studies Section

per cent and reduce carbon emissions by 3 per cent to 6 per cent per kWh of electricity generated (IEA, 2008).

Improvements in efficiency do yield a significant improvement regarding carbon emissions. Figure 3.13 shows the relationship between efficiency and carbon emissions.

Figure 3.13: Impact of fuel efficiencies on the carbon emissions of fossil fuel power plants



Source: IEA 2008

In order to calculate the life cycle emissions of carbon from LNG, we use the breakdown provided by Jaramillo (2000) which shows the extent to which each part of the LNG chain accounts for the total carbon dioxide emissions. Essentially the natural gas and LNG chains are the same except for the liquefaction, tanker transport and LNG gasification stages which are additional to the natural gas chain.

The liquefaction, transport, and gasification of LNG account for between 0.09-0.23 gCO_2eq/kWh, or on average approximately account for 15.91 per cent of the total life cycle emissions. Thus, on the basis of total natural gas emissions, LNG emissions can be estimated as between 510 gCO_2eq/kWh and 904 gCO_2eq/kWh.

Table 3.13: Total (lifecycle) emissions from natural gas and LNG in 2010, 2020 and 2030 in gCO_2eq/kWh (NB: for electricity generation)

Source	2010	2020	2030
Natural gas	680	400* 680	200* 400
LNG	707	463* 707	200* 463

Source: SQW Energy and IAEA *assuming CCS deployment

3.4.3 Supply and infrastructure vulnerability

There are potentially some impacts to the pipeline infrastructure due to more extreme weather patterns.There are also potential impacts on the North Sea mining infrastructure in the same way as there is for oil. Severe weather conditions can affect the transportation of LNG. There will be no impact on the availability of the resource due to climate change.

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The Irish Energy Tetralemma

Fuel Report 4: Peat

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel cost	▪ Notwithstanding the fact that the use of peat will be phased out by 2020, it is included for comparison and completeness of fuels reviewed. ▪ Peat is a relatively cheap fossil fuel in Ireland. Only coal is cheaper. ▪ Peat is used as a fuel by very few countries. As a result it is not internationally traded in significant quantities. All of Ireland's peat use is from indigenous reserves and therefore the price of peat is taken as the price Bord na Móna charge to Irish power stations. ▪ The real price of peat is expected to remain constant to 2030 at around €29.50/tonne.
Delivered energy cost	▪ Whilst the price of peat is assumed to remain constant in real terms, the technology used and the value for money aspects are expected to have an impact on the delivered cost. Currently the delivered cost of energy from peat (defined as the levelised cost of generation) is approximately €12/GJ. This is expected to rise to €17/GJ in 2020 and €27.7 GJ in 2030. ▪ The market price of carbon could have a considerable impact on the competitiveness of peat-based generation (which is very carbon-intensive). Carbon capture and storage (CCS) is seen as both an opportunity (to generate extra revenue) and an ongoing-cost (as it has a significant capital and operational cost). Ireland has a very good potential to deploy and operate CCS schemes. Developers would only invest in CCS if it is financially viable (a combination of appropriate carbon price and public sector funding) and therefore CCS has a broadly neutral effect on the delivered cost of energy from peat. ▪ The most recently commissioned Irish peat-fired plants (Edenderry – 120MW, Lanesboro – 100MW, and Shannonbridge – 150MW) employ efficient fluidized bed combustion technologies. Any future capacity developments are also likely to employ these technologies with CCS capability.
Policy & Regulation	▪ Compared to the other fossil fuels, peat is at a slight advantage. Despite a number of barriers to the use of peat, there also exists an incentive in terms of policy and regulation. ▪ At the European level, a range of regulatory burdens exist to peat power generation including: EU Emissions Trading Scheme (EU ETS), EU Directives on ambient air quality and EU Integrated Pollution Prevention and Control Directive and the pending Soil Directive. This situation is likely to be compounded for peat with the next

	phases of the EU ETS and the forthcoming EU Energy and Climate Package. ▪ At an Irish level, peat has particular importance as a domestic fuel source. To reinforce Ireland's security of supply peat is given special status. Peat-firing power stations are supported by a public service obligation which requires electricity to be purchased from them. The additional costs incurred through doing so are recuperated through a levy on the final electricity costs for consumers. ▪ Peat's competitiveness in the context of policy and regulation, could improve if carbon capture and storage (CCS) is supported at the national and EU levels. The EU framework already aims to develop a number of strategic large-scale CCS facilities and the draft proposal for a EU Carbon Capture and Storage Directive will reinforce this. Both of these could potentially benefit Ireland.
Market context in Ireland	▪ As an indigenous fuel resource peat plays a special role in Ireland. Ireland has recently added new peat-fired generation capacity and connections to the grid have not experienced major difficulties.

Security of supply

Import dependence	▪ As an indigenous resource it carries very little risk in terms of supply. ▪ In addition, peat comprises just a small proportion of total primary energy requirement (TPER); however this is expected to slightly increase in future years.
Fuel place of origin	▪ All peat used in Ireland is from indigenous resources. This situation is not expected to change before 2030.
Supply and infrastructure resilience	▪ As an indigenous fuel the Irish supply chain and infrastructure requirement of peat is less complex than other fossil fuels. Once extracted, Irish peat is easily moved by rail and road to Ireland's peat burning power stations. The majority of peat supplied to power stations (and briquetting plants) is carried by rail wagons on narrow gauge tracks.
Market volatility	▪ Peat is less susceptible to market volatility with the market security for peat being very high. The only significant supply risks are the seasonal fluctuations in the peat harvest that are dependent upon satisfactory weather conditions.
Energy availability and intermittency	▪ Being a solid fuel, it is easily stored and not prone to damaging spills and leaks. Unlike most renewables, peat does not suffer from intermittency problems.

Sustainability

Fuel longevity	▪ Peat is one of the least sustainable fuels examined, along with biogas. ▪ Peat reserves in Ireland are subject to measurement variations. IEA suggest that reserves may last another 10-15 years, whilst current reserves and production levels of Bord na Móna produce a ratio of approximately 30-40 years.
Environmental impact	▪ Peat is among the more appealing fossil fuel option but clearly worse off compared to all renewables. ▪ The development of peat lands are ecologically damaging with a great deal of damage to the environment during peatland preparation. In the first stage, the stripping of the layer of vegetation on the surface of the bog creates destruction to a rare habitat (peat bogs have extremely fragile ecological conditions due to the peculiar nature of their environment) as well as major changes in the visual aspect of the peatland. Drained bogs are then vulnerable to fire in certain conditions and during production a large amount of dust may be blown from the surface on windy days.

Climate change

Carbon content	▪ Peat has one of highest carbon contents of all fuels researched with the IPCC provide the carbon emission values for peat at 106 tCO_2/TJ.
Lifecycle carbon footprint	▪ Peat has one of the highest carbon footprints. Peat bogs are a huge store for carbon dioxide. In order to be prepared for producing energy peatlands must be drained, at which point they emit quantities of nitrogen oxide and methane. After draining the peatlands the carbon dioxide absorption ceases and carbon dioxide is instead emitted. The peatlands are then prepared and harvested and the machinery required for this also emit a certain amount of carbon dioxide. The peat is then combusted and it is at this point that large quantities of carbon dioxide are released. ▪ The life cycle analysis of peat shows that peat cycles in Ireland amount to 1,150 gCO_2/kWh.
Supply and infrastructure vulnerability	▪ Peat is fairly resilient to climate change in the short term but its performance deteriorates due to wetter weather conditions which may affect the production process. ▪ Only minor impacts are expected to the physical infrastructure as a result of climate change, but these may increase in the future.
Availability change	▪ Peat will not be affected by climate change directly, although wetter weather will have implications on the production cycle.

4.1: Peat: the basics

Peat is formed from the incomplete breakdown of wetland vegetation. Deposits exist in wetlands throughout the world where natural drainage of rainwater is impeded. The organic components of peat vary according to the degree of decomposition. Air-dried peat has a slightly higher energy content than wood while processed peat products approach the low end of the coal spectrum of calorific value.

Peat can be extracted using two methods: 1) by cutting sods, which are traditionally hand-cut but now predominantly harvested mechanically or 2) fine granules can be extracted using a mechanical miller to disturb and granulate the top layer of the peat bog surface. Peat in situ contains around 90 per cent water; some of this is removed by drainage and most of the remainder by drying in the wind/sun. The resulting 'air-dried' peat has a moisture content of 40-50 per cent. The bulk of peat used in electricity/heat generation production is obtained by milling. A proportion of the milled peat is converted into briquettes, which provide a convenient household fuel[1].

There is a lack of agreement as to whether or not peat is a fossil or a renewable fuel. In 2000, it was proposed that peat should be referred to as a 'slowly renewable fuel' (Crill, Hargreaves and Korhola, 2000). The Intergovernmental Panel on Climate Change (IPCC) changed the classification of peat from fossil fuel to a separate category between fossil and renewable fuels[2]. Peat now has its own category: 'peat'. Theoretically, peatland has the capacity to regenerate at a rate of 1.5 cm annually, but due to modern harvesting techniques and commercial development, regeneration is not considered viable. Currently, harvesting depletes the peatland reserves by 10 cm annually[3].

1 World Energy Council , 2007, *Survey of Energy Resources* 2007

2 25th session of IPCC, Port Louis, Mauritius, 2006

3 Green, C. Forest Ecosystem Research Group, University College Dublin. Current and Future Perspectives on the Energy Sector in Ireland Available at: http://www.sei.ie/uploadedfiles/RenewableEnergy/CurrentFutureperspectivesenergyinIrelandPPTCarlyGreen.pdf

4.2: Peat as a commodity

4.2.1 Global reserves

The measurement of peat resources on a global scale is difficult as data for many countries is imprecise or only partially ascertained. Despite this, it is clear that the world possesses a huge tonnage of peat overall. The total area of peatland, based on reports from WEC Member Committees and published sources[4], comes to over 2.7 million km^2 or about 2 per cent of the world's land surface. A considerable proportion of the world's peatlands is located in North America and the northern parts of Asia; significant deposits also occur in northern and central Europe and in Indonesia, whilst further accumulations have been identified in tropical Africa, Latin America and southern/eastern Asia.

The WEC (2007) estimates the total volume of peat in situ to be approximately 3,500 to 4,000 billion m^3. The peat reserve base in major producing countries (covering 'reserves currently under active cultivation or economically recoverable under current market conditions') has been assessed[5] as 5,267 million tonnes (air-dried).

Total consumption reported for 2004[6] was 17.3 million tonnes. Recorded production was considerably lower, at around 13.5 million tonnes. The balance of supply came out of stock, a normal feature of the peat supply/demand picture, reflecting the substantial (and unavoidable) year-to-year variations in peat production as a result of the prevailing weather during the harvesting period.

The US Geological Survey (USGS) estimated there to be 10,000,000 m^3 of global peat reserves that could currently be economically extracted or produced. With production in 2007 of around 26,000 m^3 the simple reserves-to-production ratio of global peat supplies using USGS figures is approximately 385 years. It must be noted however that as peat naturally regenerates this number is likely to be an underestimate.

Table 4.1: Forecast global peat reserves in 2010, 2020 and 2030

	Production (cubic metres per year)	Reserves (cubic metres)	Year remaining
2007	25,900	10,000,000	386
2010	25,900	9,922,300	383
2020	25,900	9,663,300	373
2030	25,900	9,404,300	363

Source: US Geological Survey (USGS) data for 2007 projected forwards.

4 Lappalainen, E., International Peat Society,1996, *Global Peat Resources*

5 Couch, 1993, referenced in WEC 2007

6 IEA, 2006, referenced in WEC 2007

Peat reserves in Ireland are subject to measurement variations similar to those internationally. IEA suggests that Irish reserves are expected to last another 15 to 20 years at current production rates[7]. Bord na Móna have an estimated total peat reserve in the region of 100 million tonnes. In 2006/07, the peat harvest totalled 2.5 million tonnes and was targeted for 3.2 million tonnes. Given these figures, Bord na Móna alone has an estimated peat reserves to production ratio of approximately 30-40 years.

4.2.2 Global production and trade

This section provides an overview of peat production in other parts of the world. Given the Ireland's current and future supply of peat will be from domestic sources, this description while not directly relevant is provided for consistency and comparisons with other fuels.

Finland, Ireland, Belarus and Estonia are the leading producer countries in decreasing order of tonnage. World peat production for 2007 was estimated to be 25.7 million metric tons a slight decrease from 2006[8]. Other significant producing countries included Russia, Sweden, Canada and Latvia. As Table 4.2 shows, peat is an important fuel source in Finland, Ireland and Belarus.

Table 4.2: World peat producers by use, 2007 (thousand metric tonnes)

	Horticultural use	Fuel use	Use not stated	Total
Finland	900	8,200	-	9,100
Ireland	500	3,800	-	4,300
Belarus:	100	2,400	-	2,500
Estonia	1,300	600	-	1,900
Russia	-	-	1,300	1,300
Sweden	380	900	-	1,280
Canada	1,250	-		1,250
Latvia	-	-	1,000	1,000
United States	635	-	-	635
Poland	500	-	-	500
Others	692	485	769	1,945
Total	6,257	16,385	3,069	25,710

Source: US Geological Survey (USGS), (2007)

7 Energy Policies of IEA Countries – Ireland 2007 Review

8 United States Geological Survey, 2007

Due to its high water content, it is not cost-effective to ship peat over large distances. The consequential low trade-volume means that data are scarce regarding the international trade of peat. The annual BP review of energy statistics excludes peat on the basis that '[the review] *comprises commercially traded fuels only. Excluded, therefore, are fuels such as wood, peat and animal waste which, though important in many countries, are unreliably documented in terms of consumption statistics.'* Similarly, the International Energy Agency (IEA) does not specify peat in its World Energy Outlook. IEA's data for peat are typically included within the 'coal' category, or bundled to produce a combined 'brown coal and peat' category.

According to SEI[9], in 2007 Ireland exported just 8 kilotonnes of oil equivalent (ktoe) of peat. This equates to approximately 1.4 per cent of the total Irish peat production. The remainder was consumed or stored domestically.

As a domestic resource, Ireland has a negligible risk in terms of its peat supply. For comparison, Ireland scores favourably in all categories used in this analysis; OECD country risk classification, World Bank Ease of Doing Business Index, and World Bank Governance Indicators (see Table 4.3 below).

Table 4.3: Country Risk, Ease of Doing Business and Governance indicators

	OECD Country Risk Classification 2008 (score from 0-7, higher figure equals higher risk)	World Bank Ease of Doing Business index 2008 (rank of 178 countries)	World Bank Governance Indicators (average score)
Ireland	0	8	1.6

Source: OECD and World Bank 2008. Note: The OECD figure measures the country credit risk, i.e. the likelihood that a country will service its external debt. The World Bank Ease of Doing Business Index measures regulations directly affecting businesses and protections of property rights. The World Bank Governance Indicators are normally distributed with a mean of zero and almost all values lying between - 2.5 and 2.5. The score here is an average of Political Stability, Government Effectiveness, Regulatory Quality, Rule of Law and Control of Corruption.

4.2.3 Peat Prices and Markets

Bord na Móna owns 80,000 hectares of peatlands, with an estimated total peat reserves in the region of 100 million tonnes[10]. In 2006 Bord na Móna acquired the 128 megawatt peat-fired generation station at Edenderry, Co Offaly. The plant uses modern fluidised bed boiler technology and supplies approximately 3 per cent of Ireland's national energy requirement.

9 2007 Provisional Energy Balance

10 Paappanen & Leinonen 2006

Bord na Móna also produces and sells milled peat feedstock for the generation of electricity at the ESB peat fired stations at West Offaly and Lough Ree in addition to the company's power station at Edenderry. Overall sales to power stations in 2007/08 were 2.4 million tonnes.

According to Bord na Móna's 2007/08 Annual Report, the total volume peat sales was 3.1 million tonnes, of which:

- 1.5 million tonnes were supplied to the Electricity Supply Board for power generation.
- 0.9 million tonnes were supplied to Bord na Móna's Edenderry Power station.
- 0.4 million tonnes of milled moss peat were supplied to Bord na Móna Horticulture Limited.
- 0.3 million tonnes were supplied to Bord na Móna Fuels Limited for the manufacture of peat briquettes.

Owing to unsuitably wet weather during the key summer harvest period in 2007, the production target of 3.2 million tonnes of milled peat was not achieved. The achieved harvest of 2.5 million tonnes was 78 per cent of target. This compared with 3.7 million tonnes harvested in the summer of 2006.

In 2006/07, Bord na Móna sold 2.4 million tonnes of peat to Irish power stations at an average price of €29.49 per tonne. Using a conversion factor of 9.76 GJ per tonne of peat (IPCC 2006) this equated to €3.02/GJ.

SEI [11] noted that the real price of peat is not expected to change between 2010 and 2020. This study has not been able to source other forecasts for peat prices and has therefore assumed that real peat prices will remain constant until 2030.

Table 4.4 below summarises the range of projected peat prices in 2010, 2020 and 2030. As noted above, current expectations do not envisage a change in the real price.

Table 4.4: Projected peat prices in 2010, 2020 and 2030 in € per tonne

Date	2010	2020	2030
Peat price	€29.49	€29.49	€29.49

Source: Bord na Móna and SEI

4.2.4 Weighted import dependence

With 701 ktoe supplied in 2007[12], peat made up 4.3 per cent of total primary energy requirement (TPER) for Ireland. This was split by 75 per cent milled peat and 25 per cent sod peat. All 186 ktoe of sod peat was used for residential consumption whilst milled peat was split between 81 per cent used in public thermal power plants and 19 per cent for briquetting

11 SEI, *Energy in Ireland 1990-2006*

12 SEI, 2007, *Provisional Energy Balance*

plants. Peat accounted for around 6.4 per cent of the electricity-generating fuel mix. All of Ireland's peat use comes from indigenous sources and there are currently no confirmed plans to begin importation.

Table 4.5 below summarises the sub-indicators that comprise the weighted import dependence indicator for peat in Ireland over the three timescales - 2010, 2020 and 2030.

Table 4.5: Projected share of fuel mix and import dependence for peat in 2010, 2020 and 2030 in per cent

Sub-indicators	2010	2020	2030
Share of the fuel mix	1%	2%	3%
Import dependence	0%	0%	0%
Weighted import dependence	0%	0%	0%

Source: SQW Energy based on research

4.3: Peat in the energy system

4.3.1 Delivered energy cost

SEI has estimated the levelised electricity costs from peat at €64.10/MWh[13] and €79.00/MWh[14]. Both estimates excludes a carbon charge. A UKERC study, which reviewed a large number of external sources, provides an estimate of peat-fired levelised electricity costs from Finland at €31.30/MWh.

4.3.2 Peat – Conversion Technologies

Ireland has three recently commissioned, modern, peat-fired power plants: Edenderry (120 MW) now owned by Bord na Móna; Lanesboro (100 MW) owned by the Electricity Supply Board (ESB); and Shannonbridge (150 MW) also owned by ESB. Edenderry was commissioned in 2000 and the two new ESB plants in 2005. These plants have an efficiency rate of around 37 per cent, much higher than the 26 per cent efficiency rate of old peat-fired plants that have now been decommissioned.

The higher efficiency rates are a result of upgrading the peat-fired stations to use fluidized bed combustion. The fluidized beds suspend solid fuels on upward-blowing jets of air during the combustion process, thus mixing gas and solids together. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer.

This study has not been able to source evidence regarding possible future technologies for peat-fired power generation. As a result, it has assumed that the present fluidized bed combustion technology will remain in common usage through to 2020 and 2030.

Table 4.6 below summarises the range of projected delivered energy prices in 2010, 2020 and 2030. Whilst the price of peat is assumed to remain constant in real terms, the technology used and the value of money are expected to have an impact on the delivered cost, which is shown as rising.

Table 4.6: Projected delivered energy prices (from peat) in 2010, 2020 and 2030 in €/GJ

	2010	2020	2030
Peat delivered energy cost	12.3	17.1	27.7

Source: SQW Energy (SES and UKERC data)

13 SEI, *Renewable Energy Resources in Ireland for 2010 2020- A Methodology*

14 SEI, *Application of portfolio analysis of the Irish generating mix in 2020*

4.3.3 Policy and regulation

The regulatory burden associated with using peat is similar to that of coal. Regulations are typically focused upon reducing the external pollutants that are the result of burning carbonaceous fuels.

The principle regulations affecting the use of peat include:

- EU Emissions Trading Scheme aims to increase the marginal cost of carbonaceous fuel use through establishing a price for carbon emissions. The ETS scheme has covered the power generation sector since its inception. When burned, peat emits higher levels of carbon dioxide than any other fossil fuel.
- A series of EU directives on ambient air quality limit values and thresholds for particular pollutants. Those included are nitrogen oxides, sulphur dioxide, lead and particulates, benzene and carbon monoxide.
- The Integrated Pollution Prevention and Control Directive (IPPC) imposes a requirement for industrial and agricultural activities with a high pollution potential to have a permit which can only be issued if certain 'Best Available Techniques' are met. The companies themselves bear responsibility for preventing and reducing any pollution they may cause, effectively enforcing minimum standards for polluting industries.
- To date, there is no legislation which is specific to the protection of soil resources. However, there is currently an EU Thematic Strategy on the protection of soil which includes a proposal for a Soil Framework Directive which proposes common principles for protecting soil across the EU. Implications for milling of peat could exist if this Directive is adapted.

As a domestic resource peat remains a core element of Ireland's energy mix in the interests of security of supply and the use of indigenous energy sources. As a consequence, peat-firing in power stations is supported by a public service obligation (PSO). The PSO requires the ESB, in its capacity as Public Electricity Supplier, to purchase electricity generated from peat. To cover the additional costs incurred ESB are obliged to charge a levy to final electricity customers. The levy is equal to the excess of the ESB's allowed costs for bought-in and owned peat fired generation over the 'Best New Entrant' price for electricity. The levy includes an economic return on investment, where relevant, and any other revenue accruing to the ESB associated directly with peat-fired generation.

4.3.4 Supply chain and infrastructure

As an indigenous fuel, the supply chain and infrastructure requirement of peat is less complex than that of imported fuels. Once extracted, peat is easily moved by rail and road to Ireland's peat burning power stations[15]. The majority of peat supplied to power stations (and briquetting plants) is carried by rail wagons on narrow gauge tracks. The train consists of a Bord na Móna designed and fabricated locomotive, pulling 16-20 milled peat wagons called a 'rake'. These wagons are loaded from the stockpile using excavators. Being a solid fuel, it is easily stored and not prone to damaging spills and leaks (Paappanen & Leinonen 2006). The

15 Alphawind, Peat Fuel Cycle, accessed via: http://www.alphawind.dk/English/uk-pages/general_information/Energy%20balance%20&%20ExterneE/Peat%20Fuel%20Cycle,%20Europeat%201,%20Ireland.doc

main weakness of peat is that the 'harvest' is reliant on favourable weather conditions. Wet-weather can significantly reduce the quantities that can be extracted.

4.3.5 Market context in Ireland

Peat plays a special role in the Irish energy supply. As an indigenous resource it plays a key role in Ireland's energy security. As a result, electricity generated from peat is given special status so that the ESB can charge a levy on consumers for the additional costs of peat-fired generation, as referred to above. Peat is likely to remain a key component of Ireland's power generation for the foreseeable future. Although more-efficient peat fired-plants have recently been completed there is a risk that peat's status as the premium indigenous supply may slightly decrease as Ireland's indigenous natural gas reserves are further developed.

There are an estimated 300 sod peat contractors operating in Ireland. These contractors are working on a small scale usually a two-man operation and produce sod turf for domestic use. Their combined share of the peat market is approximately 20 per cent[16]. The vast majority of peat, 80 per cent, is produced by Bord na Móna[17].

4.3.6 Market volatility

As an indigenous fuel, the market security for peat is very high. The only significant supply risks are the seasonal fluctuations in the peat harvest that are dependent upon satisfactory weather conditions.

4.3.7 Environmental impacts

The development of peat lands are ecologically damaging and in Ireland do not fair well with the public. There is a great deal of damage to the environment during peatland preparation. In the first stage, the stripping of the layer of vegetation on the surface of the bog creates destruction to a rare habitat (peat bogs have extremely fragile ecological conditions due to the peculiar nature of their environment) as well as major changes in the visual aspect of the peatland. Drained bogs are then vulnerable to fire in certain conditions and during production a large amount of dust may be blown from the surface on windy days.

Excluding global warming the most severe damages associated with peat bogs are public health impacts. These are specifically due to the emissions of nitrogen and sulphur oxides. Effects over time depend on how much of the un- drained peat will be extracted.

Table 4.7 below summarises the level of environmental impacts (externalities) expressed as Euros per mega-watt of power generated (€/MWh) over the three timescales - 2010, 2020 and 2030. Given that only current externality costs are reported in the literature, this study assumes that these costs will remain the same in real terms over the timescale discussed.

16 McGettigan and Duffy, 2001, *Consumption of Peat Energy*

17 Lappalainen, E., International Peat Society ,1996, *Global Peat Resources*

Table 4.7: Environmental Impact of peat - externality cost - in 2010, 2020 and 2030 in €/MWh

	2010	2020	2030
Peat	35	35	35

Source: ExternE 1998: Externalities of Energy, European Commission

4.4: Peat and climate change

4.4.1 Carbon content of fuel

The IPCC provide the carbon emission values for Peat at 106 tCO_2/TJ, as shown in Table 4.8.

Table 4.8: Carbon content of peat in 2010, 2020 and 2030 in tCO_2/TJ

Source	2010	2020	2030
Peat	106	106	106

Source: IPCC

4.4.2 Lifecycle carbon footprint

The Irish national implementation of the ExternE methodology developed a life cycle assessment of a peat powered station that was yet to be built at the time of analysis. In this analysis the life cycle of global warming gases in the peat fuel cycle are described. Peat bogs are a huge store for carbon dioxide. In order to be prepared for producing energy, peatlands must be drained, at which point they emit quantities of nitrogen oxide and methane. After draining the peatlands the carbon dioxide absorption ceases and carbon dioxide is instead emitted. The peatlands are then prepared and harvested and the machinery required for this also emit a certain amount of carbon dioxide. The peat is then combusted and it is at this point that large quantities of carbon dioxide are released.

According to a Trinity College Dublin (2007) study the life cycle analysis of peat shows that peat cycles in Ireland amount to 1,150 gCO_2/kWh. No specific references were identified for future levels of lifecycle carbon emissions from peat and therefore this study assumes that the current levels will be broadly maintained to 2020 and 2030 but allows for a slight reduction due to likely combustion efficiencies.

Table 4.9: Carbon content of peat in 2010, 2020 and 2030 in tCO_2/TJ

Source	2010	2020	2030
Peat - value use in the Index	1,150	1,140	1,130

Source: Trinity College Dublin, 2007

4.4.3 Supply and infrastructure vulnerability

Only minor impacts are expected to the physical infrastructure as a result of climate change, but these may increase in the future. The main risk arises from peat fires - once peat bogs are drained they are generally more vulnerable to fires. This was the case in Indonesia where in 1997 climate-induces fires (attributed to the El Niño phenomenon) resulted in burning peat bogs which in turn made significant contributions of CO_2 to the atmosphere. The fires not only destroyed thousands of acres of forest but also left peat bogs smoldering for months. The effects on biodiversity were also large. Given Ireland's climate however, this risk is rather minimal.

Also, there will be no impact on the availability of the resource due to climate change.

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The Irish Energy Tetralemma

Fuel Report 5: Biomass

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ Biomass is one of the few renewable fuel sources with a fuel cost. The cost varies significantly depending on the source of the fuel, conversion technology and location. ▪ Woody biomass can be cheap to procure, particularly where it can be sourced as a clean wood residue from industry. Costs increase if the unprocessed fuel has to be transported for long distances, and as cheaper sources of fuel are exhausted. ▪ Non-woody biomass is typically converted to secondary fuels before use. This makes them more convenient to use and cheaper and easier to transport. However it increases the cost of the fuel compared to unprocessed biomass. ▪ The cost associated with bio-residues and biogas depends on the source and nature of the fuel. Some biomass residues can have a negative cost (or "gate fee") – for example, from avoided costs of disposal. In other cases, alternative markets for the bio-residue can lead to a price for the fuel.
Delivered energy cost	▪ Woody biomass is a relatively expensive fuel for electricity production, though co-firing with fossil fuel can reduce costs, and it can also be combusted directly to produce heat. ▪ The delivered cost for non-woody biomass used in transport is that of the respective transport fuel (e.g. biodiesel, bio-ethanol). ▪ Delivered costs for bio-residues and biogas are relatively cheap.
Policy & Regulation	▪ Biogas is the most viable fuel in term of policy support. ▪ Regulations regarding air quality and the handling and disposal of waste can present barriers to biomass energy schemes. Planning and building regulations are also a common barrier where new technologies are concerned, though moves such as the recent planning exemption for domestic pellet boilers will help to address these barriers. Public opposition to energy from waste projects can be a significant barrier to bio-residue schemes. ▪ An ambitious, overarching renewable energy strategy, supported by specific targets, grant and revenue support schemes, forms the foundation of a highly supportive incentive regime for biomass energy.
Market context in Ireland	▪ Biomass is currently one of the more widely used renewable energy sources in Ireland, and there is a relatively mature supply chain and market. This is further reinforced by the supportive government policies. ▪ The large agricultural and food & drinks sectors are a very good

	prerequisite for further uptake of biomass energy. This is underpinned by a diverse supplier base which comprises a large number of farmers, entrepreneurs and SMEs. Ireland possesses skills and experience relevant to this group of fuels.

Security of supply

Import dependence	▪ At present, the majority of Ireland's biomass fuel is locally produced. The exception to this rule is biofuels for transport, where almost 50 per cent of fuel was imported in 2007. ▪ The proportion of imports might need to rise for this and other biomass fuel types as renewable energy targets become increasingly challenging.
Fuel place of origin	▪ Most biomass is sourced locally and is therefore highly secure. The only exception is non-woody biomass, much of which is imported from a range of countries. ▪ There is an active global market for biomass fuels, and a wide range of countries from which Ireland can source imported biomass, in addition to local resource.
Supply and infrastructure resilience	▪ The requirement for a fuel supply chain makes biomass infrastructure more complicated and fragile than most other renewable fuels. Dependence on locally grown feedstock can make supply vulnerable to interruption. ▪ The robustness of supply chains will improve as the market in woody biomass develops; however, the infrastructure will remain fragile relative to other renewable energy sources. ▪ The conversion of biomass into an intermediate fuel (e.g. for transport biofuels and wood pellets) yields a standardised, energy-dense commodity that can be more easily handled, traded and used, at the cost of increased complexity in the supply chain.
Market volatility	▪ Biogas is virtually not subject to market fluctuations. With bio-residues broadly similar but less secure. In contrast, woody biomass is subject to volatile markets a. With non-woody biomass being similar. ▪ Rapid growth in demand for biomass energy could place pressure on biomass supply in the short term. There are alternative markets for many biomass fuels, which will have an effect on availability and prices, as will policy measures in associated areas (for example, relating to waste reduction). ▪ Biomass has a finite supply potential in terms of an economically viable resource. This is because the Irish indigenous supply is limited and importing biomass has a transport cost. Moreover, agricultural land has a range of uses; mainly for food production

	and growing biomass (or breeding cattle) will compete with biomass for energy uses. Therefore, the market is inherently volatile.
Energy availability and intermittency	▪ Biomass can be stored and as a result its availability is relatively high compared to other renewable sources. ▪ Biomass power plants have a relatively high capacity factor of 85 per cent.

Sustainability

Fuel longevity	▪ Biomass is a renewable resource and therefore it will be available indefinitely. ▪ The only exception to this is bio-gas, which is mainly represented by landfill gas, where due to the Landfill Directive (EU, 1999), biodegradable waste to landfill must reduce progressively in the next couple of decades. Whilst in practice it will remain a renewable resource, its availability will become rather short-term and, according to other research; will last for about 2 years on a replenishable basis.
Environmental impact	▪ Biomass fuels have a relatively low impact, but worse than that of other renewables (due to long and complex supply chains). ▪ Environmental impacts include soil erosion, fertilizer use and particulate matter from combustion.

Climate change

Carbon content	▪ Woody and non-woody biomass have a very high carbon content but due to their cyclical nature they are considered nearly carbon neutral. Biogas has net carbon emissions when combusted. Bio-residues have a very high carbon content and are not offset by a natural sequestration cycle. ▪ The carbon content factors of the different typed of biomass fuels is provided by the IPCC (2006). These are: ▪ woody biomass – 112 tCO_2/TJ ▪ non woody biomass – 70 tCO_2/TJ ▪ bio-residue – 100 tCO_2/TJ ▪ bio-gas – 54.6 tCO_2/TJ
Lifecycle carbon footprint	▪ Woody and non woody biomass: Generally the use of biomass at the electricity generation stage is defined as a ‘carbon-neutral’ because the CO_2 released during combustion is absorbed during fuel/plant growth. Life-cycle emissions for biomass systems vary substantially depending on the combustion efficiency, power rate

	and the type of feed (e.g. chips vs. logs vs. pellets vs. gas). ▪ Bio Residue and Biogas: Biogas will have a very low total GHG emissions (we estimate it as the low end of woody biomass emissions). This is because the bio gas is extracted from landfill sites and municipal waste which produce GHG gases purely as a by product of their existence. There is a small carbon impact however, as not all the gas may be captured and biogas power plants may operate on low levels of fossil fuel to provide some energy for conversion processes to be undertaken. Furthermore, the construction of the site will have to be allocated to the production of electricity or heat over the lifetime, which will also increase the carbon per kWh emitted.
Supply and infrastructure vulnerability	▪ Biogas and bio-residue are the least vulnerable fuels in the group and achieve the highest index score. Woody biomass would be vulnerable in the longer term as climate change intensifies. Non-woody biomass is fairly vulnerable and by 2030 is shown to be the most impacted. ▪ Biomass fuels are vulnerable to climate change mainly in terms of the supply chain. Key vulnerability is the potential failure of biomass crops due to bad or extreme weather – most pertinent to non-woody biomass. Extreme climate could also create logistical challenges especially as biomass is associated with a complex, multi-step production and supply.
Availability change	▪ Biomass fuels will be among those most impacted by climate change. Overall availability is expected to increase with a longer growing season.

5.1: Biomass: the basics

For the purposes of this study biofuels have been split into four different categories: woody biomass, non-woody biomass, bio-residues and bio-gas, see definitions below. This distinction does not prejudice the current and future applications of each fuel or the conversion methods applied. For instance, while woody biomass is currently used primarily for direct combustion (for heat and power) it may in the future be possible to use it as a liquid biofuel source.

Woody biomass: This sub-category covers all combustible energy crops such as wood, wood residues (forest, sawmill and clean construction waste), coppiced willow, miscanthus and straw. Woody biomass is commonly used in both heat and power production as a fuel source, either on a stand-alone basis, or by co-firing with fossil fuels such as coal or peat.

Non-woody biomass: The non-woody biomass sub-category covers existing sources of liquid biofuels (bioethanol, bio-oil and biodiesel), including sugar and starch crops, oil plants and recycled vegetable oil and animal fats.

Bio-residues: This sub-category covers organic industrial residues including agricultural slurries, food and catering wastes and the biodegradable fraction of municipal solid waste.

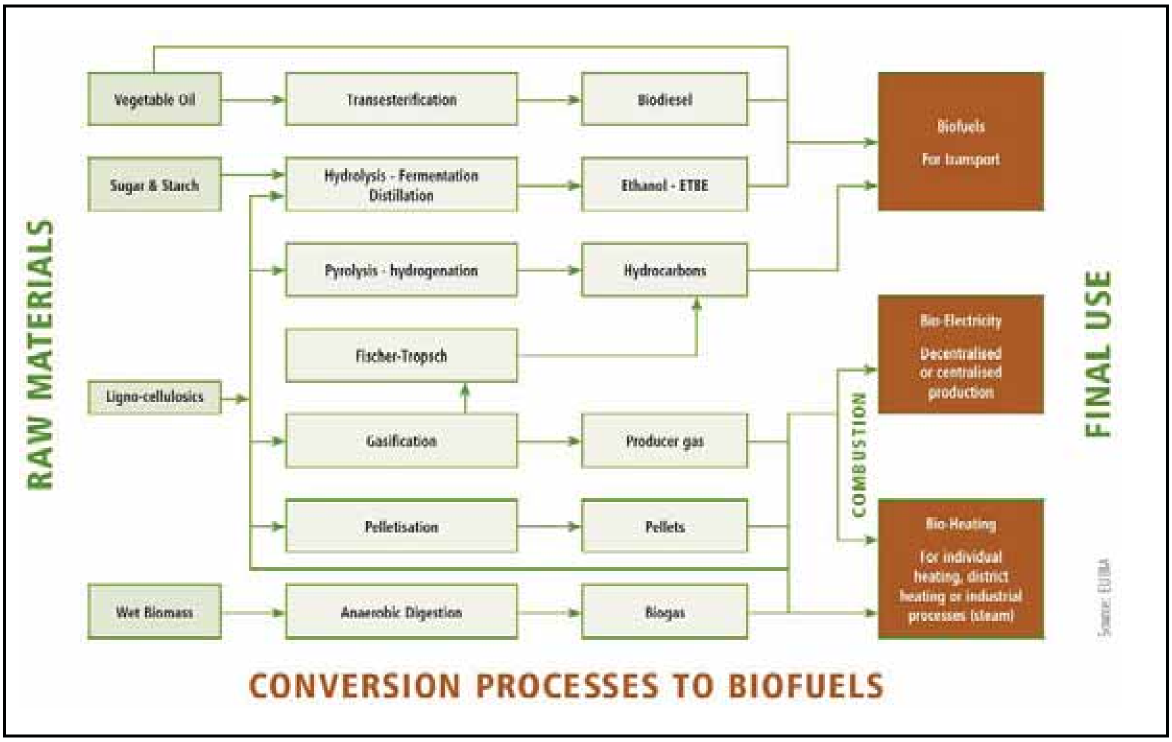
Bio-gas: The bio-gas sub-category covers landfill gas (produced through the natural breakdown of waste deposited in a landfill) and sewage gas.

Next generation biofuels: Second generation biofuels include biohydrogen and biomethanol manufactured from left-over parts of plants that have already been used for food (stalks, shells, husks and roots which are not edible, for instance). Third generation biofuels include the growth of algae for manufacturing into algal fuel and biobutanol. While these sources could play a significant role in energy supply in the future, they are not considered to be sufficiently commercially developed for inclusion in this study.

5.1.1 Uses of biofuels

Figure 5.1 below shows the variety in potential uses and transformation processes involved with biomass energy, from raw fuels to final use. The alternative uses are discussed below in more detail.

Figure 5.1: Biomass energy: from fuels through transformation processes to final use



Source: European Biomass Industry Association (2006)

Electricity

In large scale electricity generation biomass can be co-fired alongside traditional fossils fuels. In Ireland there is a target to replace 30 per cent of peat used in peat-fired power stations with biomass by 2015. Potential sources of biomass identified as suitable for co-firing include miscanthus, willow, hemp and reed canary grass (woody biomass) and meat and bone meal (bio-residues). Biomass can also be used as a stand-alone fuel to generate electricity or combined and heat (CHP), though the cost of a dedicated biomass system can make this option significantly more expensive than co-firing, which can be incorporated into an existing fossil fuel plant.

Landfill gas is widely used to generate electricity. Wells are drilled into landfill sites and the gas collected in them is transported by pipes to local electricity generation plants. Sewage gas can also be used for electricity generation. Through the process of digestion and incineration, sewage produces a combustible biogas (a mixture of methane, carbon dioxide, hydrogen sulphide, nitrogen and hydrogen) that can be used to generate energy.

Heat

Biomass of all kinds can be burned to generate useful heat, from a domestic log fireplace or wood pellet boiler to on-site industrial heat generation in, for example, a sawmill or a distillery.

Combined heat and power (CHP)

CHP plants can be fired by traditional fossil fuels, or equally by biomass. Above 1-2 MW conventional steam turbine technology can be used with reasonable efficiency. At high demand levels, biomass can be gasified and used to fuel a gas turbine. At lower output requirements biomass systems using internal combustion engines, Stirling engines and gas micro-turbines are considered to be more appropriate.[1]

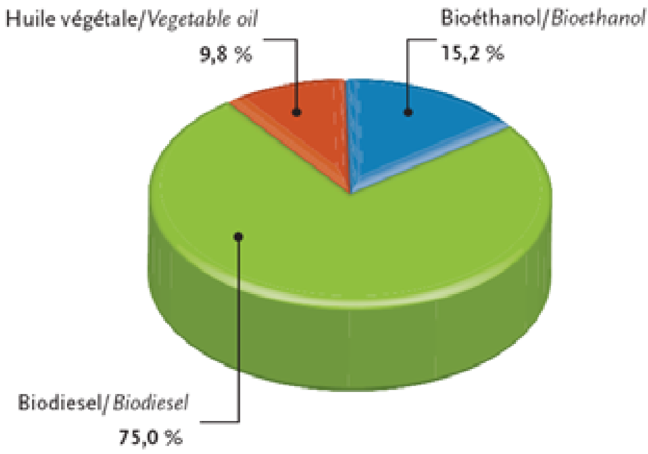
Transport

There are three main types of biofuels used for transport:

- Biodiesel made from pure plant oil, recovered vegetable oil or tallow. This is typically blended with diesel in a 5 per cent mix.
- Bioethanol made from sugar beet, wheat, whey or other crops. This is usually blended with petrol in a 5 per cent bioethanol/petrol mix or in an 85 per cent mix for use in flexible fuel vehicles.
- Pure, unblended plant oil can be directly used in diesel vehicles, though engines require modification before use[2].

Figure 5.2 below shows the share of each biofuel in the EU energy mix in 2007, where biodiesel plays a predominant role. All of the above fuels are categorised as non-woody biomass for the purposes of this study.

Figure 5.2: Share of different transport biofuel types in EU consumption, 2007



Source: EurObserv'ER (2008)

Principle energy vectors

Most of the biofuels considered in this study can be converted into useful energy in several different ways. These separate "energy vectors" can have quite distinct characteristics across all indicators, including delivered energy cost, regulatory barriers and incentives and environmental impacts. For example, woody biomass can be used in anything from domestic heating to industrial CHP and co-firing for electricity generation.

1 Forestry Commission, UK, 2008

2 Department of Communications, Marine and Natural Resources (DCMNR), 2007a, *Energy White Paper, Delivering a Sustainable Energy Future for Ireland*

In order to come up with representative figures, this analysis is based on a limited number of key conversion technologies, as shown in Table 5.1 below. The technologies selected are chosen on the basis of their potential share of the available biomass resource, from now until 2030.

Table 5.1: Principal energy vectors for biomass fuels

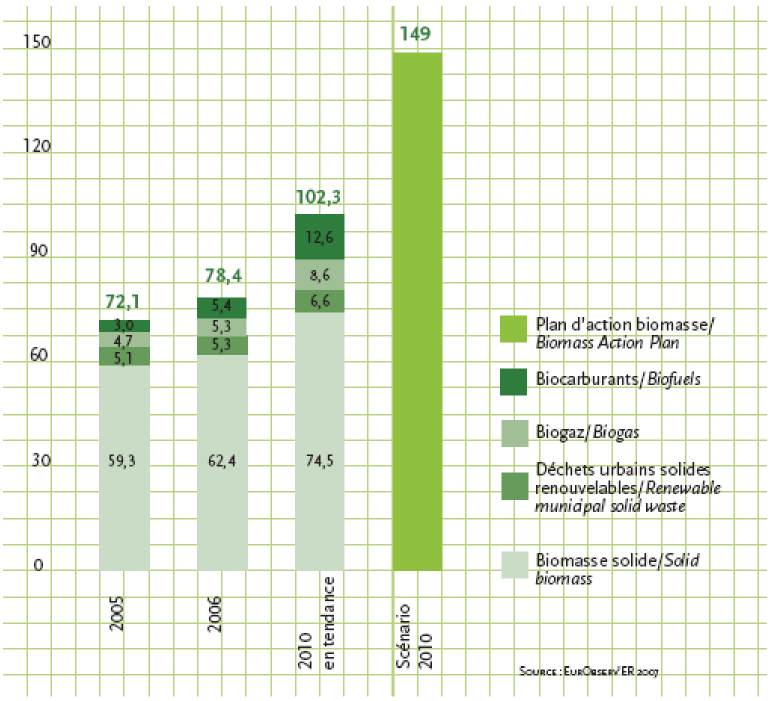
Fuel	2010	2020	2030
Woody biomass	Clean wood waste (electricity)	Clean wood waste (electricity)	Clean wood waste (electricity)
Non-woody biomass	Biofuel (transport)	Biofuel (transport)	Biofuel (transport)
Bio-residues	Energy from Waste (CHP)	Energy from Waste (CHP)	Energy from Waste (CHP)
Biogas	Landfill/sewage gas (electricity)	Landfill/sewage gas (electricity)	Landfill/sewage gas (electricity)

Source: SQW Energy

5.1.2 European context

The European Commission has committed to a Biomass Action Plan, with targets to significantly increase the use of biomass across the EU. Figure 5.3 below shows progress against the 2010 target for EU biomass usage, including the contributions from the different biomass fuel types.

Figure 5.3: Current, trend and target biomass fuel use in the European Community, 2006

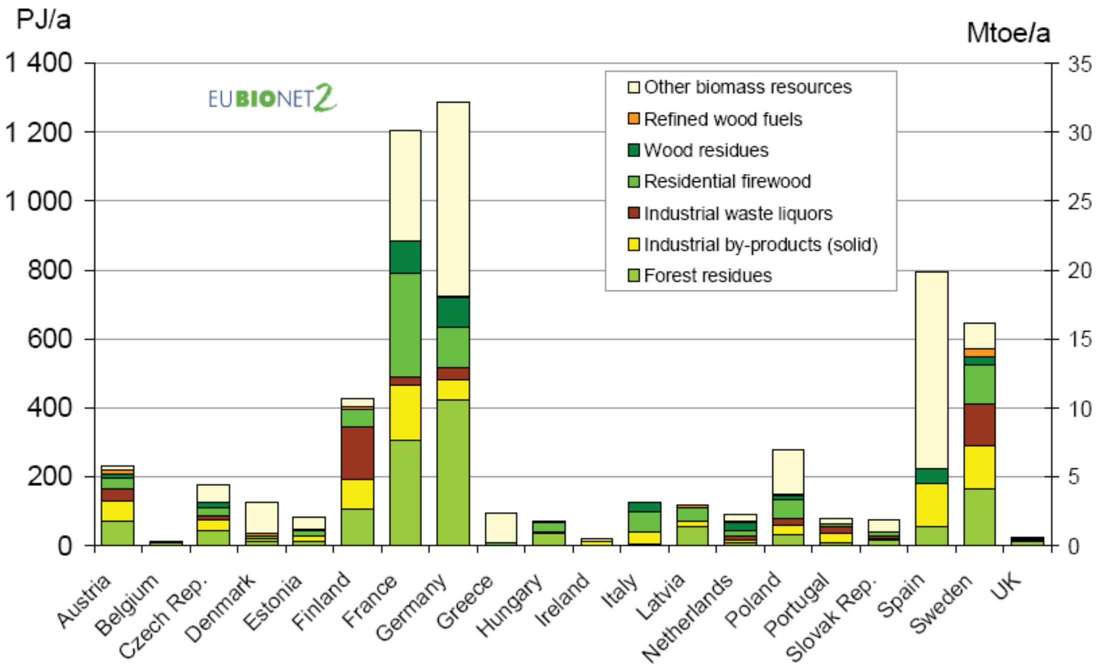


Source: EurObserv'ER (2007)

The principle biomass fuel source at present is solid biomass (mostly woody biomass – see below). While strong growth is forecast across all sectors, it appears unlikely that the 2010 EC target will be met.

Figure 5.4 below shows estimated economically viable biomass resources available for energy consumption for 20 EU member states in 2007 (reported under the EUBIONET II programme)[3]. The chart shows a wide variety of unevenly distributed resources – the different fuel types are examined in more detail below. Wood and wood by-products account for nearly 50 per cent of total potential resource.

Figure 5.4: Estimated biomass resources in the EU in peta-jouels per annum (PJ/a) and million tonnes of oil equivalent per annum (Mtoe/a)



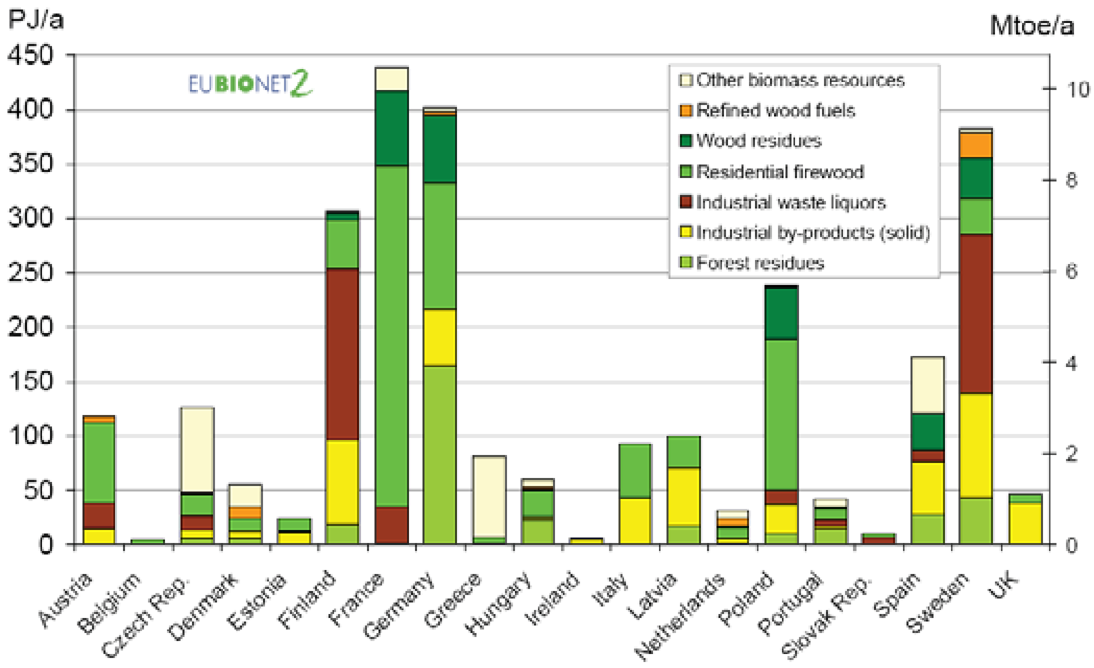
Source: EUBIONET (2007)

Figure 5.5 summarises how much of the available resource was actually used in 2004[4]. Residential firewood was the most abundantly used biomass, accounting for over a third of total usage (although accurate figures are difficult to establish). According to this study, Ireland consumed 30 per cent of its available biomass energy resource in 2004.

3 Member states were asked to report the economically viable resource, not the theoretical resource, which is usually much larger

4 EUBIONET, 2007, *Biomass fuel trade in Europe*, EUBIONET II, Summary Report

Figure 5.5: Biomass consumption for energy in EU member states in 2004

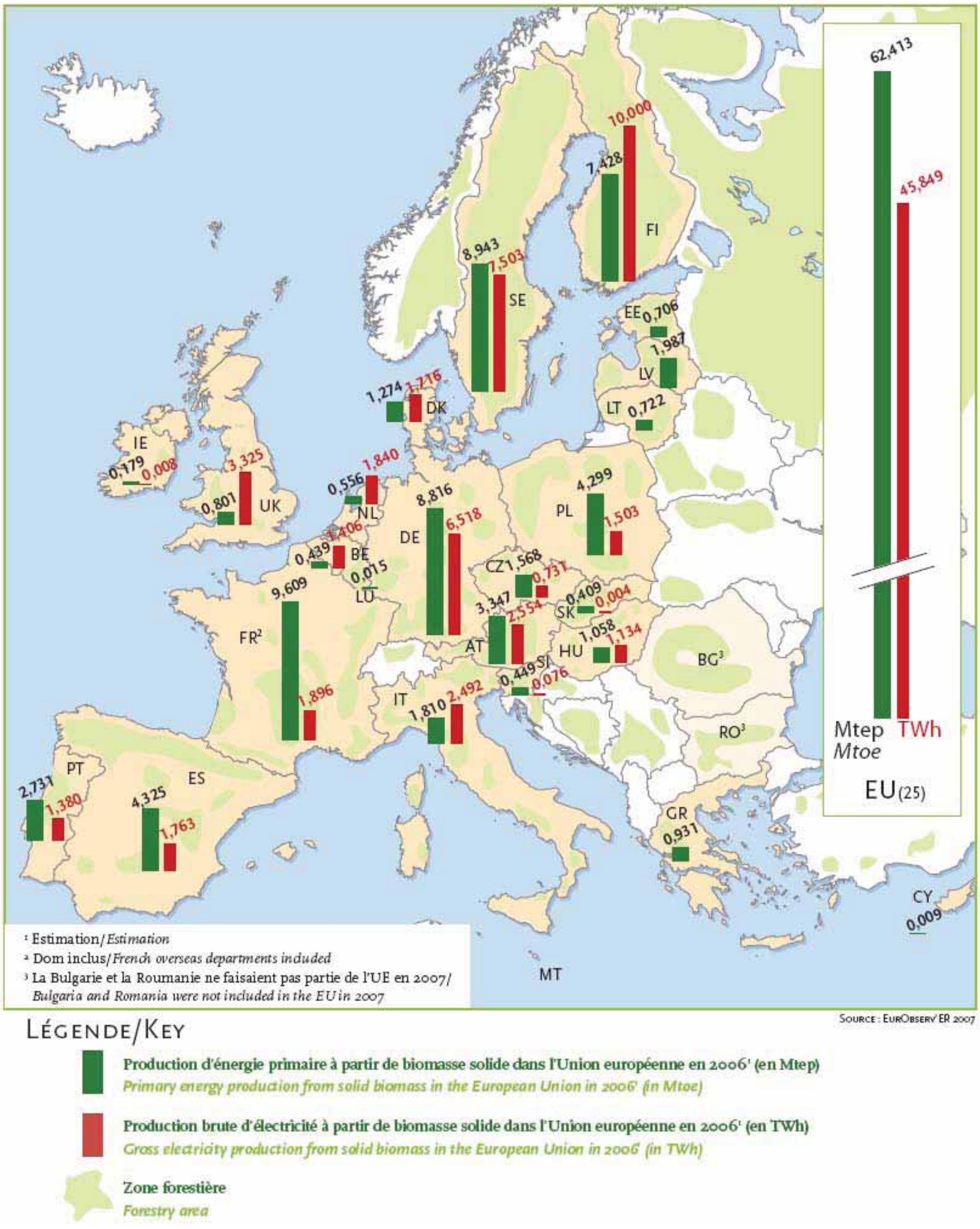


Source: EUBIONET (2007)

Woody biomass

Figure 5.6 below shows energy production from solid biomass in the EU in 2006 (the lighter green bars show total primary energy production from biomass in million tonnes of oil equivalent (Mtoe), the darker red bars show biomass electricity production in TWh).

Figure 5.6: Energy production from solid biomass in the EU, 2006



Source: EurObserv'ER (2007)

The study above shows that Ireland produces 0.042 tonnes of oil equivalent (toe) from solid biomass per inhabitant. This is one of the lowest levels in the EU; the highest usage is 1,413 toe per inhabitant in Finland (which is by far the largest bioenergy user in the world).

Table 5.2 below shows the breakdown of solid biomass usage by fuel type. This shows that the majority of solid biomass comes from wood and waste wood, although organic waste (mostly straw, crop residues and other agricultural by-products) and black liquor (a bio-residue of paper manufacturing) also account for a significant share.

Table 5.2: Solid biomass use in the EU by fuel type

Pays/ ***Countries***	**Bois/** ***Wood***	**Déchets de bois et granulés/** ***Wood Waste and pellets****	**Autres matières végétales et déchets/** ***Organic materials and wastes*****	**Liqueur noire/** ***Black Liquor***	**Total**
France/*France**	7,561	1,149	0,270	0,797	**9,777**
Suède/*Sweden*	0,768	2,547	1,052	3,571	**7,937**
Finlande/*Finland*	1,077	2,343	0,015	3,158	**6,592**
Pologne/*Poland*	2,572	1,560	0,048	0,000	**4,180**
Espagne/*Spain*	2,729	0,445	0,898	0,104	**4,176**
Autriche/*Austria*	1,489	0,982	0,307	0,587	**3,365**
Rép. tchèque/*Czech Rep.*	0,905	0,271	0,015	0,269	**1,460**
Danemark/*Denmark*	0,422	0,396	0,460	0,000	**1,277**
Hongrie/*Hungary*	0,542	0,423	0,032	0,005	**1,003**
Grèce/*Greece*	0,028	0,000	0,929	0,000	**0,957**
Belgique/*Belgium*	0,192	0,178	0,019	0,039	**0,428**
Irlande/*Ireland*	0,016	0,109	0,050	0,000	**0,175**
Total	**18,300**	**10,402**	**4,094**	**8,530**	**41,327**

* DOM inclus pour la France. La répartition entre le bois et les déchets de bois a été estimée par Observ'ER/ *Overseas departments included for France. The breakdown between wood and wood waste is estimated by Observ'ER.*

** Inclus plaquettes, sciures et autres déchets de bois/ *Included wood chips, sawdust and other wood wastes.*

*** Inclus paille, résidus de récoltes, matières animales, autres déchets organiques/ *Included straw, crops residues, animal materials and other organic wastes.*

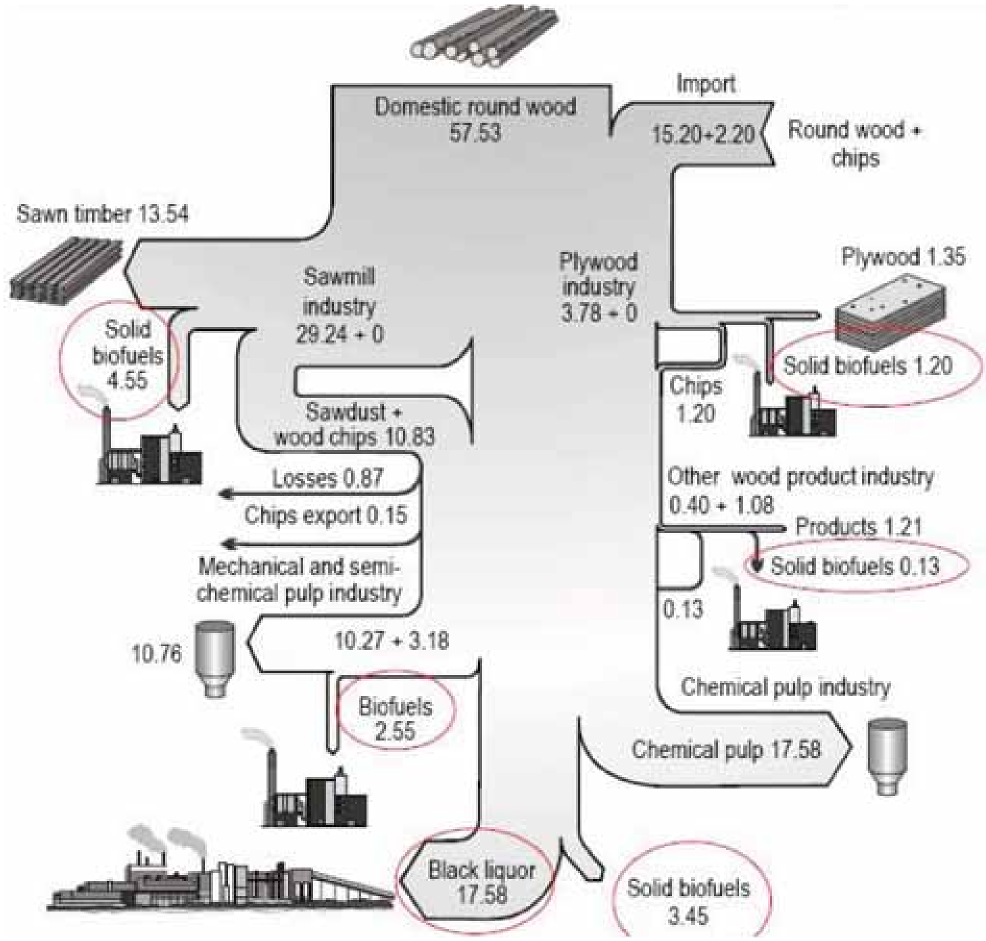
Note : Les résultats concernent 69,7 % de la production primaire de l'Union européenne en 2005/ *These results concern 69,7 % of the primary production of solid biomass in the EU in 2005.*

Source : EurObserv'ER 2007

Source: EurObserv'ER (2007)

Energy conversion forms only part of an integrated, international market for wood products. Figure 5.7 below shows wood streams in the Finnish forest industry in 2004 (in units of million m^3). It illustrates not only the wide variety of different uses for wood biomass, but also that energy can be extracted from almost every point in the supply chain.

Figure 5.7: Wood streams in the Finnish forest industry, 2004

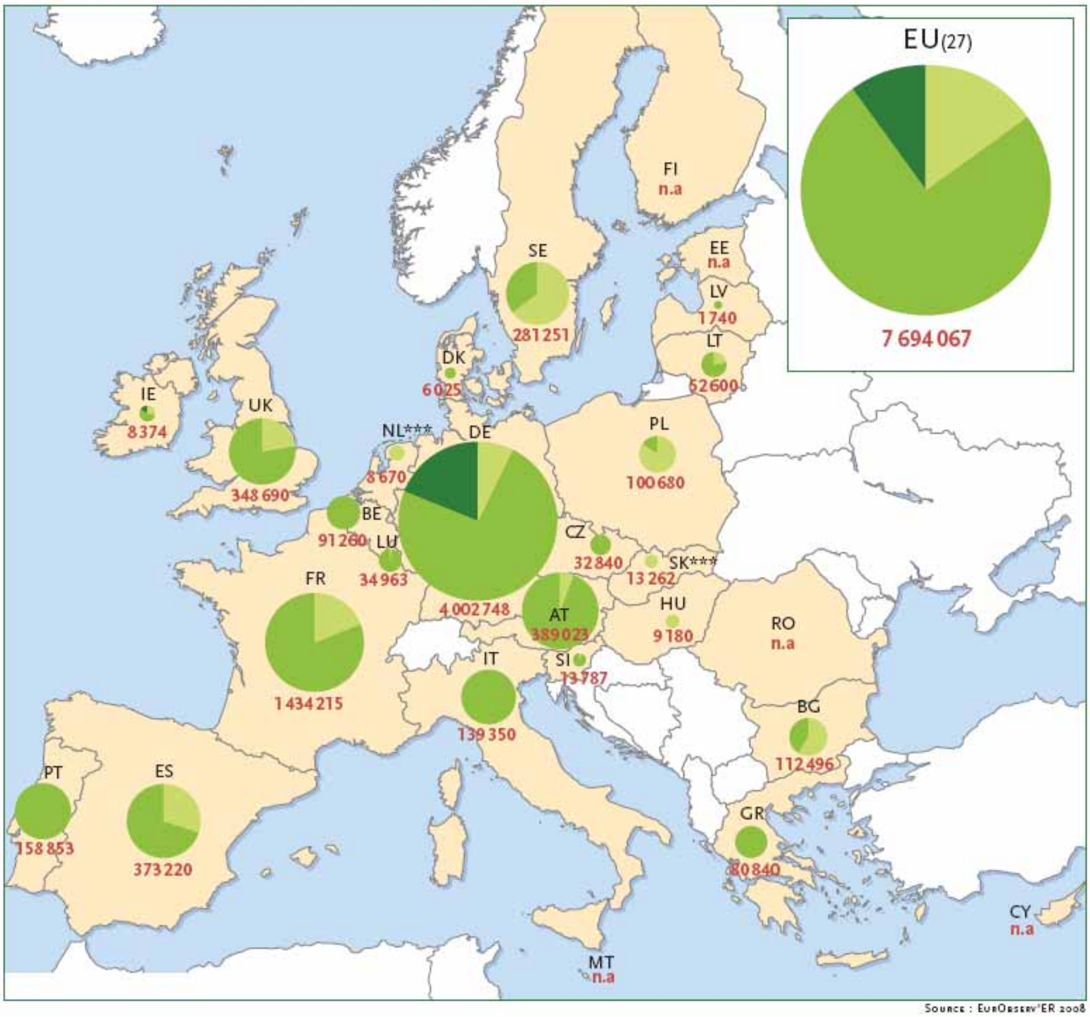


Source: International Energy Agency (2008)

Non-woody biomass

Figure 5.8 below shows energy production from transport biofuels by EU country in 2007 (in units of tonnes of oil equivalent).

Figure 5.8: Transport Biofuel consumption in EU countries, 2007 (estimated)



Légende/Key

Consommation de biocarburants destinés au transport dans l'Union européenne en 2007 (en tep)*, avec les parts respectives de chaque filière/*Biofuels consumption for transport in European Union in 2007 (in toe)* with respective shares of each sector.*

Bioéthanol/*Bioethanol* Biodiesel/*Biodiesel* Autres/*Other*

Les chiffres en rouge indiquent la consommation totale/*Red figures show total consumption*

n.a. Non disponible/*Not available.*
* Estimation/*Estimation.*
** Huile végétale consommée pure pour l'Allemagne, l'Irlande et les Pays-Bas et biogaz pour la Suède/*Vegetable oil consumed as such in Germany, Ireland and The Netherlands, and biogas for Sweden.*
*** La consommation de biodiesel existe mais n'était pas disponible à la date de l'enquête/*Biodiesel consumption exists but was not available during the survey.*

Source: EurObserv'ER (2008)

Consumption of biofuels has grown rapidly in recent years in response to the EU Biofuels Directive, under which Member States have agreed binding targets for biofuel usage by 2010. Recent questions surrounding the sustainability of some biofuels (Euractive, 2008a[5]) and impacts on food prices have lead the European Commission to rethink their biofuel targets. The 5.8 per cent target for 2010 is under review, with the latest proposal being a 4 per cent target in 2010, rising to 5 per cent and 10 per cent in 2015 and 2020 (subject to sustainability criteria being met)[6].

Bio-residues

The European Commission defines a clear hierarchy in waste management. Member States are asked to take appropriate measures to promote:

- the prevention or reduction of waste production;
- the exploitation of waste by recycling, re-use or recovery; and
- the use of waste as a source of energy.[7]

Under this hierarchy, incineration is the last possible means for treating or processing waste before resorting to disposal. Nevertheless the recovery of energy from waste is widespread within the EU, though with significant differences in the level of adoption between member states.

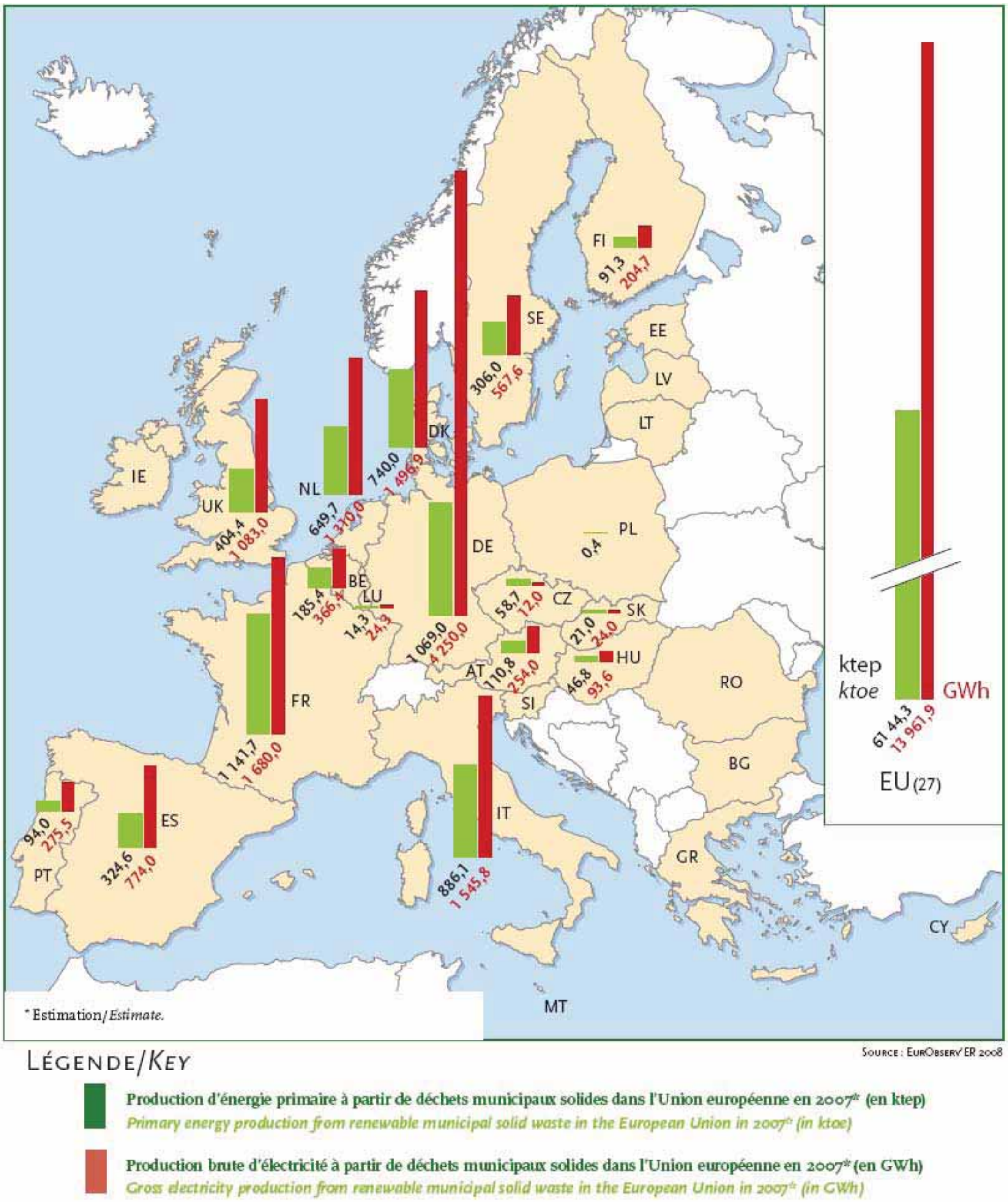
Figure 5.9 below shows energy production from the renewable component of Municipal Solid Waste (MSW) in the EU in 2007 (the lighter green bars show total primary energy production from MSW in ktoe, the darker red bars show MSW electricity production in GWh).

5 Euractive, 2008a, *Biofuels, Trade and Sustainability*

6 Euractive, 2008a, *Biofuels, Trade and Sustainability*

7 Article 3 of the 2006 Biofuels Directive

Figure 5.9: EU energy production from renewable MSW in 2007



Source: EurObserv'ER (2008a) * Estimated

In Ireland, Indaver commenced the construction of a waste-to-energy facility in Carranstown, Duleek, Co Meath in September 2008. The proposed waste-to-energy facility will result in a 90 per cent reduction in the volume of waste going to landfill, generate enough electricity to power over 19,000 homes (equivalent to the towns of Drogheda and Navan combined).

The use of bio-residues for waste is covered by two key pieces of European legislation:

- The **Waste Incineration Directive** (EU, 2000). "The aim of this Directive is to minimise the impact of negative environmental effects on the environment and human health resulting from emissions to air, soil, surface and ground water from the incineration and co-incineration of waste." The Directive was transposed into Irish law in 2003. One of the impacts of the Directive is to increase the costs of incinerating waste biomass by imposing technical and monitoring requirements on the site. The additional cost of WID compliance in a new plant is much less than the cost of retro-fitting WID compliance to an existing facility[8].

- The **Landfill Directive** (EU, 1999). The Directive's overall aim is "to prevent or reduce as far as possible negative effects on the environment, in particular the pollution of surface water, groundwater, soil and air, and on the global environment, including the greenhouse effect, as well as any resulting risk to human health, from the landfilling of waste, during the whole life-cycle of the landfill". The Directive was transposed into Irish law in 2004. One of the key impacts of the Directive is the development of a *landfill tax* – a levy imposed on the disposal of waste to landfill. By increasing the cost of landfilling the levy encourages alternative forms of disposal, including waste to energy. The Irish Landfill Levy was introduced in 2003 at a rate of €15 per tonne, raised to €20 per tonne in 2008. Other member states countries have imposed measures ranging from landfill taxes to outright bans on different waste streams[9].

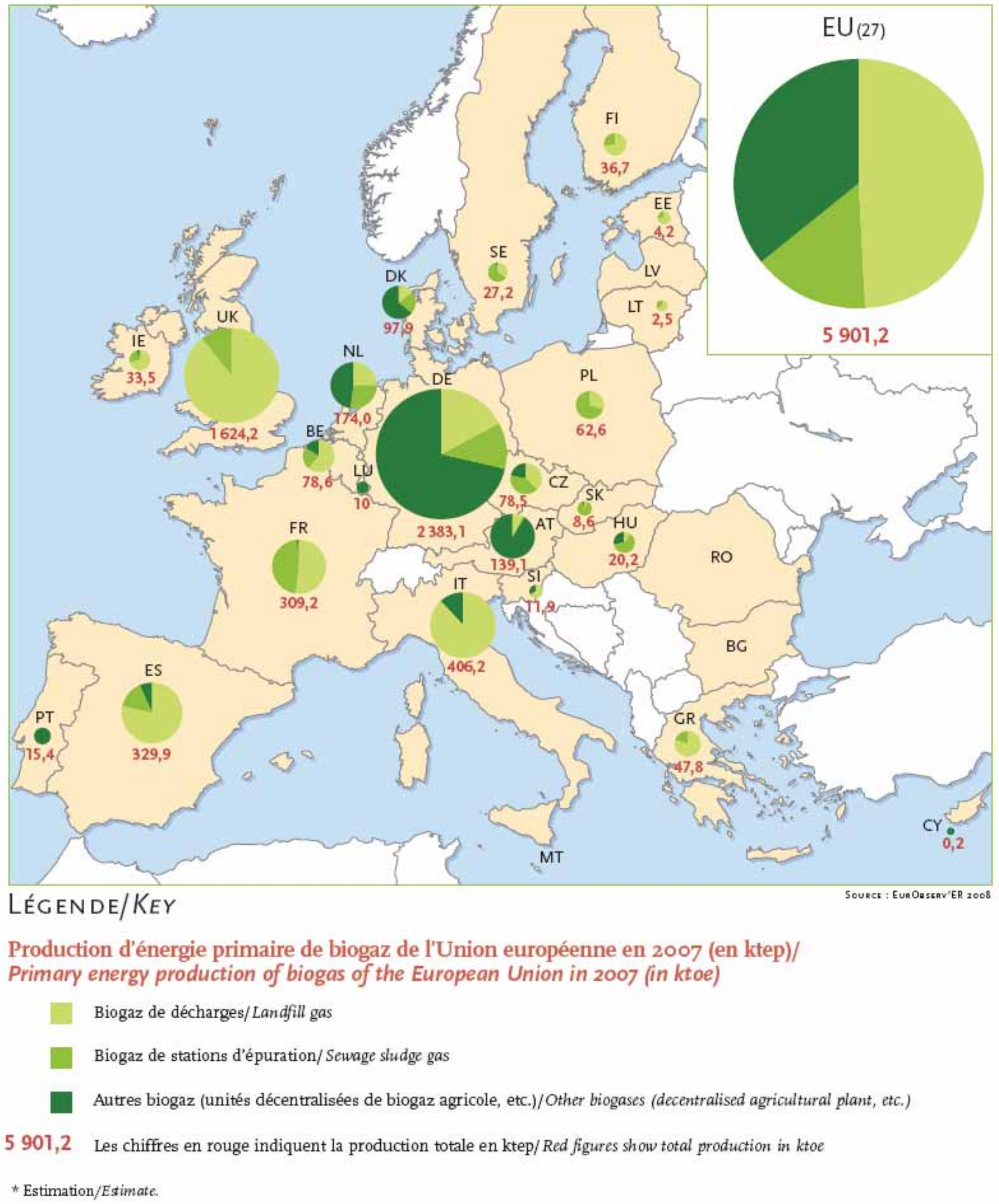
Biogas

Figure 5.10 below shows EU energy production from biogas in 2007. Production from landfill gas, sewage gas and anaerobic digestion of animal waste are all shown separately.

8 UK Department for Environment, Food and Rural Affairs (DEFRA), 2008, *Waste Wood as a Biomass Fuel*

9 Confederation of European Waste-to-Energy Plants (CEWEP), 2007, *Summary of Landfill Taxes and Bans*

Figure 5.10: Energy production from biogas in Europe, 2007 (estimated)



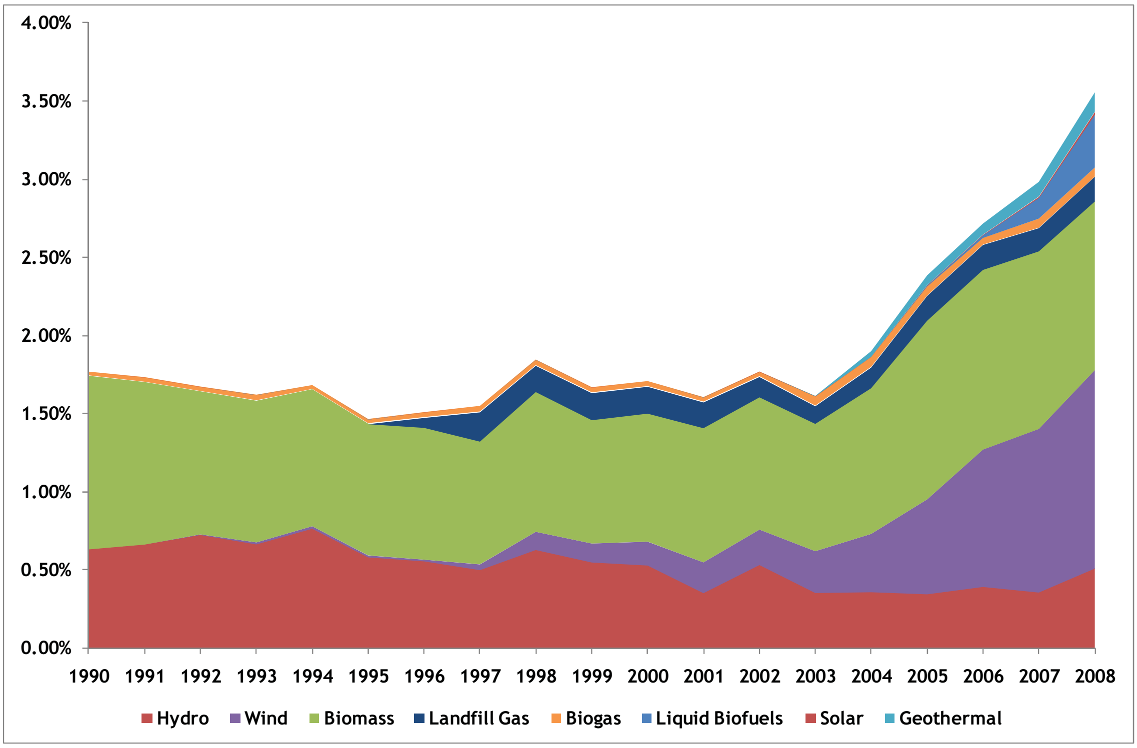
Source: EurObserv'ER (2008b)

Growth up to 2007 was driven largely by deployment of small-scale agricultural biomass generators in Germany. At the end of 2007, Germany had around 3,750 agricultural biogas production units, where a typical plant methanises a mix of animal slurry and energy crops. The rapid growth was a response to generous production incentives however increased costs for devices and feedstock[10] combined with changes in the incentive regime are likely to slow the rate of growth.

5.1.3 Irish context

Figure 5.11 below shows the contribution of renewable sources to total primary energy requirement (TPER). While the overall proportion of energy supply from renewables is small (2.9 per cent), biomass plays a significant role ("biomass" below consists largely of wood waste use for thermal energy).

Figure 5.11: Renewable Energy Contribution to TPER, 1990-2008



Source: SEI, Energy in Ireland 1990-2008, 2008 report

The Irish Government's Energy White Paper, *Delivering a Sustainable Energy Future for Ireland* (DCMNR, 2007); includes a number of targets with particular relevance to bioenergy, including:

- A target to generate 12 per cent of heat demand from renewable sources by 2020 (it is likely that biomass would need to contribute more than 90 per cent of this target);
- 30 per cent co-firing with biomass at the three peat power plants by 2015;

10 The cereal most used is maize, whose price increased by 83 per cent between October 2006 and 2007 (from 18 to 33 euros per ton, excluding transport and silaging costs)

- 800 MWe of Combined Heat and Power (CHP) with an "emphasis on biomass fuelled CHP"; and
- 10 per cent of transport fuel demand met by biofuels.

The high-level targets and the progress towards them are summarised in Table 5.3 below.

Table 5.3: Ireland's progress towards renewable energy targets

% of each target (% of which biomass)	1990	1995	2000	2005	2006	2007	2008	2009	2010 target	2020 Target
Renewable electricity (RES-E)	4.9% (0%)	4.1% (0%)	5.0% (8%)	6.8% (7%)	8.6% (5%)	9.4% (5%)	-	-	15%	40%
Renewable Transport (RES-T)	-	-	-	-	0.1% (100%)	0.5% (100%)	-	-	3%	10%
Renewable Heat (RES-H)	2.6% (100%)	2.1% (100%)	2.4% (100%)	3.3% (100%)	3.5% (100%)	3.4% (99%)	-	-	5%	12%
Proportion of TPES	2.2%	1.9%	2.0%	2.7%	3.0%	3.3%	-	-	-	16%

Source: SEI (2008). Figures and targets are expressed as a proportion of Total Primary Energy Supply (TPES)

In March 2007, the Bioenergy Action Plan for Ireland was published[11]. This includes an analysis of the potential for biomass to help meet Ireland's renewable energy targets, the current barriers and opportunities faced by the sector, and fifty measures for departments and agencies to take to implement the Action Plan.

11 Department of Communications, Marine and Natural Resources (DCMNR), 2007a, *Energy White Paper, Delivering a Sustainable Energy Future for Ireland*

A range of measures have already been enacted to encourage the use of biomass for energy, including:

- the Greener Homes scheme, which promotes domestic renewable energy heating;
- the Renewable Heat (ReHeat) Deployment Programme, which assists deployment of renewable heating systems in industrial, commercial, public and community premises;
- the CHP deployment programme, which includes provisions favouring biomass;
- the REFIT programme, which provides revenue support for electricity from renewable sources;
- the Renewable Transport Fuels Biofuels Obligation, which requires fuel supply companies to ensure that biofuels represent a rising per centage of their fuel sales;
- tax exemptions for biofuels; and
- development of comprehensive training programmes for biomass energy installers.

A Bioenergy Working Group has been established by DCENR and SEI, with the goal of developing a sustainable bioenergy supply roadmap towards the national renewable energy targets for 2020.

The policy context for biomass energy in Ireland is therefore very favourable. However, there are a number of factors that should be considered:

- The sustainability of EC biofuels strategy has been brought into question. This could eventually impact on the biofuel targets of EC member states.
- Current support programmes for biomass energy do not extend to 2020. Achievement of the 2020 targets is likely to require significant long-term investment; the policy framework required to achieve these targets is still under development.
- Bioenergy can be very capital intensive, and the economic case for biomass is sensitive to the price of alternative conventional fuels. The ongoing financial downturn could contribute to high costs of capital, low fossil fuel prices and constraints on the availability of government support over the next few years. These will be testing conditions for government commitments in all policy areas – renewable energy and biomass will be no exception.

5.2: Biomass as a commodity

5.2.1 Fuel longevity

Woody and non woody biomass can effectively be classified as renewable resources that will not diminish over time. However, bio-gas which is extracted primarily from landfill and municipal wastes are subject to the amount of biomass material in landfill – this is set to diminish as a result of stringent waste regulation across the EU. With regards to bio-residues, whilst the amount produced as a by-product of other practices cannot necessarily be relied on as a self replenishing source, it is mainly based on economic activity which is expected to continue at least at its current scale and even grow.

There are currently five landfill gas projects in Ireland, with a combined electrical capacity of 15 MW. Many other sites could be exploited (with an estimated total resource by 2020 of over 300 MW), but timing for extraction is crucial; the resource must be utilised in the coming decade or it will be lost. On a given site, utilisation depends on gas quality, yield and economics of extraction, which in turn are related to scale.

Into the future, policy is moving strongly away from landfill and this will reduce the available resource. On the other hand, any new landfill sites will be larger and more modern in design and management than the typical current site, and so exploitation of the resource will become more economically viable.

Ireland's agricultural sector creates significant quantities of dry residues, principally straw, poultry litter and spent mushroom compost, all of which can be combusted to produce electricity, heat or both. Total straw production in Ireland is of the order of 1.1 Mt to 1.4 Mt (agricultural reform should see the total resource shrinking over time). Current uses are animal bedding, the production of mushroom compost, and ploughing back. Analysis of the likely energy resource has focused on this third use as the most likely to be available for diversion to bioenergy uses. Geographical factors are also important; cereal production is most intense in the east and south-east, and the economics of straw utilisation depend heavily on transportation costs.

With a typical energy value of 13.5 MJ/kg (at a moisture content of 20 per cent), the theoretical straw energy resource is calculated to be about 16-20PJ (4500-5500 GWh). The SEI study examining the resource estimated that in reality about 10 per cent of this would be available for utilisation on a practical and economic basis, i.e. 1.8PJ, or 500 GWh.

The majority of straw is ploughed back in to the land, as demand does not exist at good prices for the farmer. Below a price of €30-35 per tonne of wheaten straw delivered, farmers are unlikely to change ploughing-in behaviour. But if markets were stable and predictable, prices would not need to rise much to attract significant interest.

Another agricultural residue with significant energy value is poultry litter. There are about 14 million birds in the Irish poultry sector at any given time, and an estimated 140,000 tonnes of spent litter is produced annually. At present, the only value added usage for this material is as an input to mushroom compost, which uses 40 per cent-70 per cent of the resource, the rest being spread on land for disposal. The key issue is the relative returns from either energy use or land spreading, which will depend on energy prices, land spreading costs, and transport costs. This has a strong geographical dimension. Almost 64 per cent of the total litter resource is produced in County Monaghan, and this region has a limited amount of land available for spreading. In other areas where land spreading is easier, it will be more difficult to attract material away from this easy and established disposal route.

The practical poultry litter resource available for energy is estimated to be 25,000 to 40,000 tonnes. This order of resource could feed an electricity generation plant of size 2.1 MW to 3.5 MW.

The Irish mushroom growing sector produces about 290,000 tonnes of spent mushroom compost annually. Most of this resource (over 80 per cent) is currently disposed of through land spreading, and so should be divertible to energy uses. Again, there are areas of high production where land available for spreading is very limited (principally Cavan and Monaghan). The best estimate for the practical resource is about 62,000 tonnes (utilisation obviously depends on the relative economics of spreading and energy production). This represents an energy value of about 0.2 PJ (i.e. it could supply an electricity plant of size 1.85 MW).

Wet residues

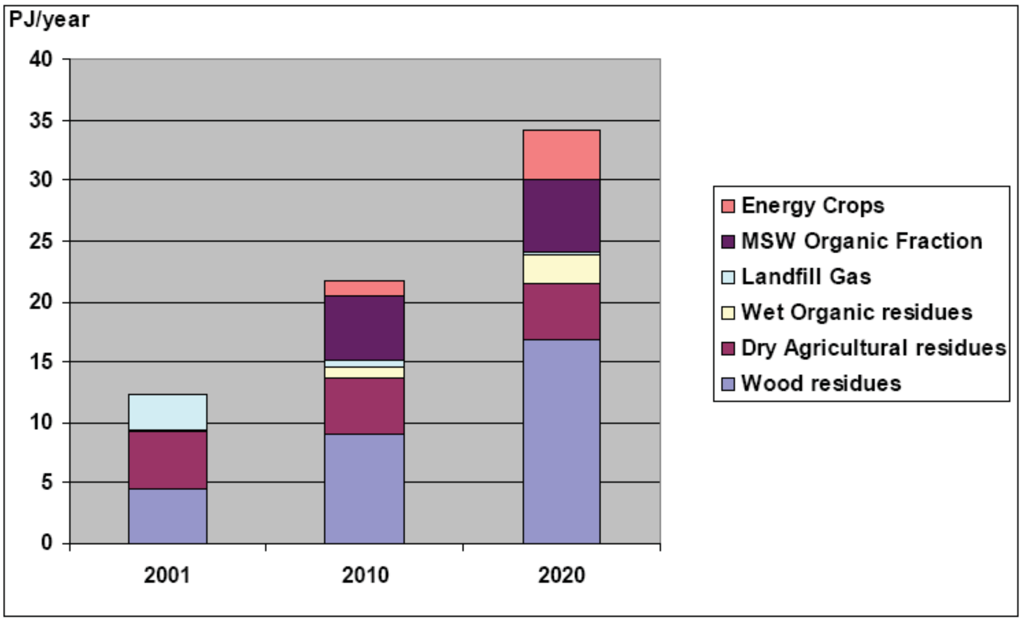
All these wet residues have potential deployment in combustion or digestion processes for energy production, and their processing can bring additional environmental benefits in terms of reducing the volumes and potencies of the waste streams. They can also benefit from gate fees where waste disposal costs are avoided and waste owners are ready to pay for their treatment. However, the resource can be dispersed and difficult to gather in sufficient quantities (especially farm wastes). There are also legislative, political and social hurdles in treating such materials, especially through combustion.

In summary, the extent to which the resource will be available in the future is dependant on the following:

- Relative prices between conventional and bioenergy;
- Competing uses of biomass (e.g. board manufacture, mushroom compost from straw);
- The practical challenges and costs of extraction, collection, collation and storage;
- The geographical limitations on transportation from source to energy use;
- Likely growth of energy crop planting, taking account of agricultural policy and supports; and
- Likely energy conversion pathways for each resource.

Figure 5.12 shows that woody and energy crops will be available over time and is dependant on direct policy and regulatory application rather than other human processes which is the case for landfill gas and bio residue. In Figure 5.12, landfill gas is shown to diminish substantially as better waste management techniques are employed in the future and as the current emissions from sites diminish absolutely. Residues as a whole are expected to increase although straw residues, as a subset of this category, are set to decrease in the future.

Figure 5.12: The growing biomass resource



Source: SEI 2004, 'Bioenergy in Ireland'

5.2.2 Fuel place of origin

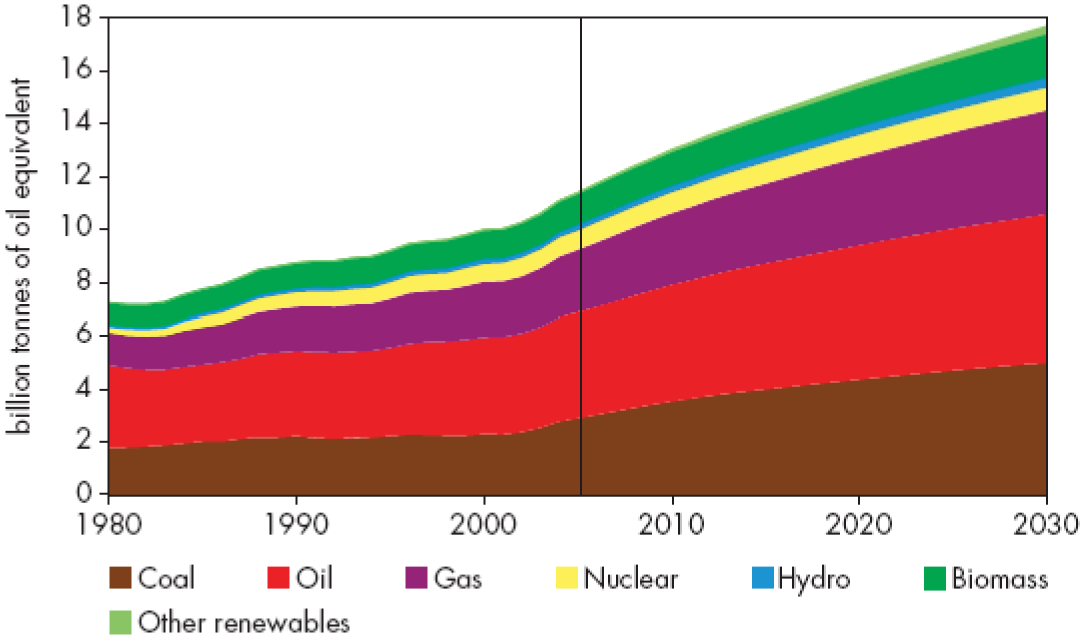
Biomass is the most commonly used renewable fuel source across the globe. Usage covers everything from domestic fires for cooking and heating in developing countries to refined biofuels for transport in the developed world.

Figure 5.13 below shows current and future projections of world energy demand under the Reference Scenario from the IEA World Energy Outlook, 2007[12]. Under this scenario absolute demand for energy from biomass and waste rises to 2030, although its share of total energy supply falls from 10 per cent to 9 per cent[13].

12 International Energy Agency (IEA), 2007, *World Energy Outlook 2007*

13 The IEA High Growth and Alternative Energy scenarios see biomass accounting for 9 per cent and 11 per cent of demand, respectively

Figure 5.13: World Primary Energy Demand in the IEA Reference Scenario



Source: IEA, 2007

Global trade in biomass fuels currently accounts for about 1,000 PJ per annum; the IEA estimates that in the long-term international trade could rise to between 80,000 and 150,000 PJ[14]. Table 5.4 below shows estimated trade volume by biomass type in 2006.

14 EUBIONET, 2007, *Biomass fuel trade in Europe*, EUBIONET II, Summary Report

Table 5.4: Overview of global biomass production and trade in 2004

Product	World production in 2004	Volume of international trade in 2004	International trade/world production, %
Industrial wood and forest products			
Industrial roundwood	1 646 million m^3	120 million m^3	7%
Wood chips and particles	197 million m^3	37 million m^3	19%
Sawn timber	416 million m^3	120 million m^3	31%
Pulp and paper production	189 million tons	42 million tons	22%
Paper and paper board	354 million tons	100 million tons	31%
Agricultural products			
Maize	727 million tons	83 million tons	11%
Wheat	630 million tons	118 million tons	19%
Barley	154 million tons	22 million tons	14%
Oats	26 million tons	2.5 million tons	18%
Rye	18 million tons	2 million tons	11%
Rice	608 million tons	28 million tons	5%
Palm oil	37 million tons	23 million tons	62%
Rape seed	46 million tons	8.5 million tons	18%
Rape seed oil	16 million tons	2.5 million tons	16%
Biomass fuels			
Ethanol	41 million m^3	3 - 4 million tons (90 PJ)	9%
Biodiesel	3.5 million tons	< 0.5 million tons (20 PJ)	14%
Fuel wood	1 772 million m^3	1.9 million m^3 (16 PJ)	8%
Charcoal	44 million tons	1.4 million tons (28 PJ)	2%
Wood pellets	4 million tons	1.2 million tons (24 PJ)	28%
Indirect trade of biomass fuels			
Industrial roundwood [a)]		410 PJ	
Wood chips and particles [b)]		130 PJ	
TOTAL BIOMASS FUELS		718 PJ	

1 million m^3 means solid m^3

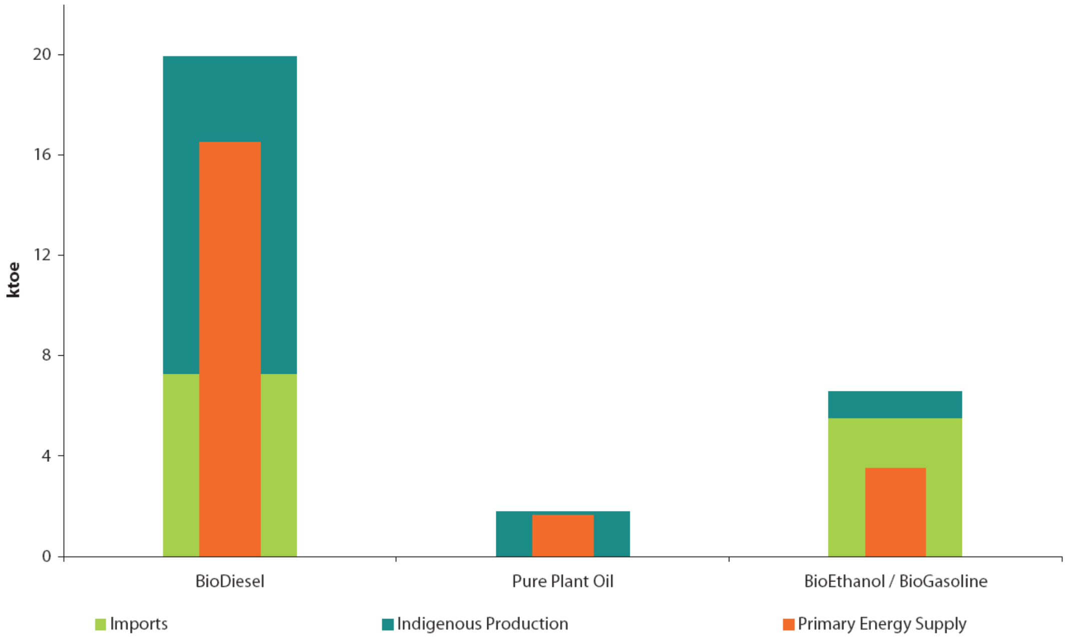
[a)] 10% bark is added in the roundwood (FAO statistic under bark), average density 0.8 ton/m^3, 45% average conversion into solid biofuels and net calorific value 9.4 GJ/ton.

[b)] average density 0.8 ton/m^3, 45% average conversion into solid biofuels and net calorific value 9.4 GJ/ton

Source: EUBIONET (2007)

At present, the majority of Ireland's biomass fuel is indigenous. The exception to this is biofuels for transport, where almost 50 per cent of fuel was imported in 2007, as illustrated in Figure 5.14 below.

Figure 5.14: Irish biofuels production, imports and usage, 2007



Source: SEI, 2008

The proportion of imports might need to rise for this and other biomass fuel types as renewable energy targets become increasingly challenging. However, we assume here that the proportion of imported biofuel remains constant into the future. There are a wide range of countries from which Ireland can source imported transport biofuels.

5.2.3 Energy availability and intermittency

Availability for woody biomass, bio-residues and biogas are taken from the UK Department of Trade and Industry (DTI 2007[15]). The woody biomass figure of 85 per cent is the average of the capacity factor for co-firing (90 per cent) and a dedicated biomass plant (80 per cent). The biogas figure of 70 per cent is the average of the sewage (80 per cent) and landfill gas (61 per cent) figures. The bio-residues figure is equated to the capacity factor of energy from waste CHP (83 per cent), a summary table is presented below, see Table 5.5.

Availability for non-woody biomass (i.e. biofuel for transport) depends on the availability of both the fuel and the vehicle. We have assumed here that the raw material for the fuel is always available, and that the refining plant (e.g. distillery) is available 95 per cent of the time (similar to oil refineries).

15 UK Department of Trade and Industry (DTI), 2007, *Costs of Electricity Production*

Table 5.5: Energy availability/intermittency for biomass fuels in per cent

Availability, per cent	2010	2020	2030
Woody biomass	85	85	85
Non-woody biomass	95	95	95
Bio-residues	83	83	83
Biogas	70	70	70

Source: SQW Energy

5.2.4 Fuel prices

The cost of biomass can vary widely between different fuel types and locations. For example, Table 5.6 below shows reported solid biomass and conventional fuel costs at industrial plants across a number of EU member states in 2004. The range of costs reported reflects differences in, for example, fuel type, local fuel markets (competitive demand for the resource) and transport costs.

Transport costs can be particularly important for unprocessed woody biomass, which is bulky and can contain up to 50 per cent water by mass. Transportation costs may limit the benefits of burning wood fuel (hauling wood biomass from outside a 80 km radius is usually not economical).

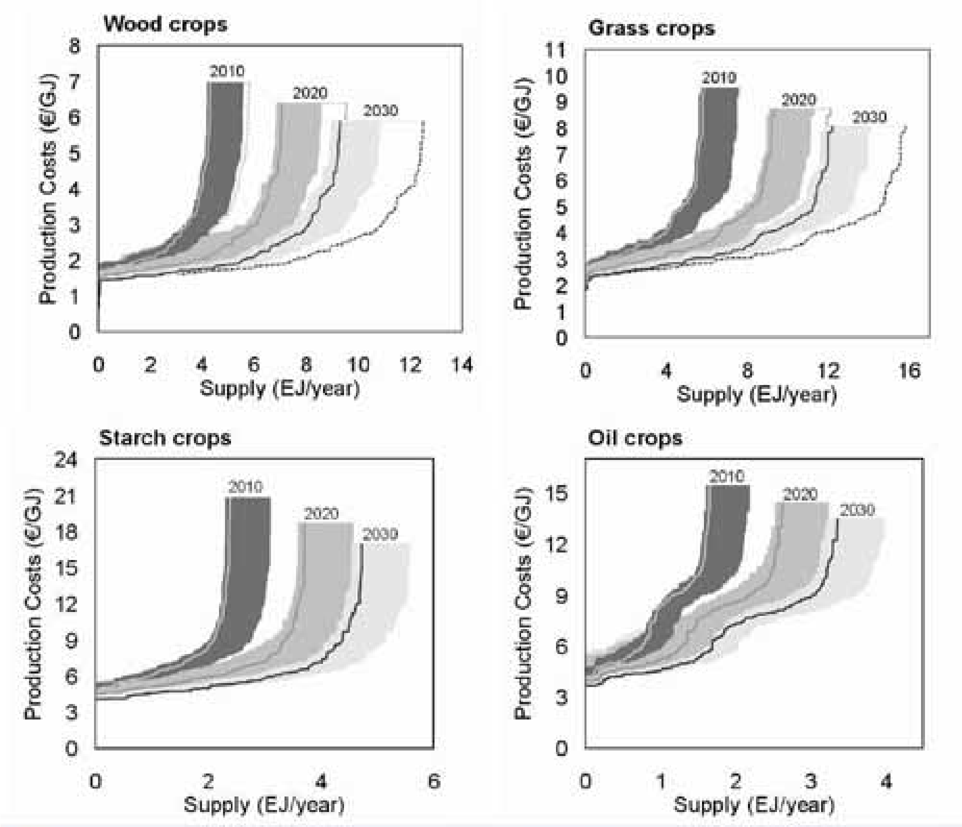
Table 5.6: Reported fuel prices at industrial plants in December 2004 (ex VAT)

€/GJ	Forest residues	Industrial by-products	Wood waste	Wood pellets	Other biomass	Heavy fuel oil	Light fuel oil	Natural gas	Coal
Austria	4.7	1.9	-	8.4	-	-	-	-	-
Belgium	-	-	-	-	-	4.1	-	5.9	-
Czech Rep.	1.8	1.6	0.2	3.6	1.5	22.7	17.8	6.3	0.8
Denmark	4.4	3.6	-	6.1	3.9	13.7	17.5	13.2	11.1
Estonia	-	1.5	-	-	-	3.5	8.9	2.4	2.3
Finland	2.8	2.2	-	5.4	-	5.3	9.8	4.5	3.8
France	4.0	1.5	1.7	4.3	2.2	4.1	-	5.1	2.8
Germany	2.2	1.1	0.9	-	-	2.6	5.9	3.8	1.3
Greece	-	1.3	-	-	-	-	-	-	-
Hungary	-	-	-	-	3.0	-	5.1	5.7	3.8
Ireland	**-**	**2.3**	**-**	**11.4**	**-**	9.4	11.9	9.9	2.1
Latvia	-	1.0	-	4.0	1.0	2.5	9.1	2.8	1.8
Netherlands	2.4	3.5	3.5	6.0	8.9	5.4	14.0	5.1	2.0
Poland	2.1	1.4	0.8	5.1	-	3.5	10.0	4.8	2.2
Portugal	2.1	4.1	-	-	-	-	-	16.6	-
Slovakia	-	2.0	-	4.6	-	5.2	9.0	4.7	2.1
Spain	-	-	-	-	2.7	6.3	13.0	3.9	-
Sweden	4.1	3.4	2.5	6.2	4.2	13.7	16.5	8.5	10.9
UK	-	-	-	-	-	6.6	-	4.2	2.1
Maximum	4.7	4.1	3.5	11.4	8.9	22.7	17.8	16.6	11.1
Average	3.0	2.2	1.6	5.9	3.4	7.2	11.4	6.3	3.5
Minimum	1.8	1.0	0.2	3.6	1.0	2.5	5.1	2.4	0.8

Source: EUBIONET (2007). “Other biomass” includes olive cake and straw bales.

As in any market, costs also depend on the level of demand – the higher a price consumers are willing to pay, the more fuel becomes available. For example, Figure 5.15 below shows resource supply curves for four biomass fuels in 2010, 2020 and 2030. The shaded areas represent bands of uncertainty, within the parameters considered in the study.

Figure 5.15: Biomass supply curves for a number of different fuel types



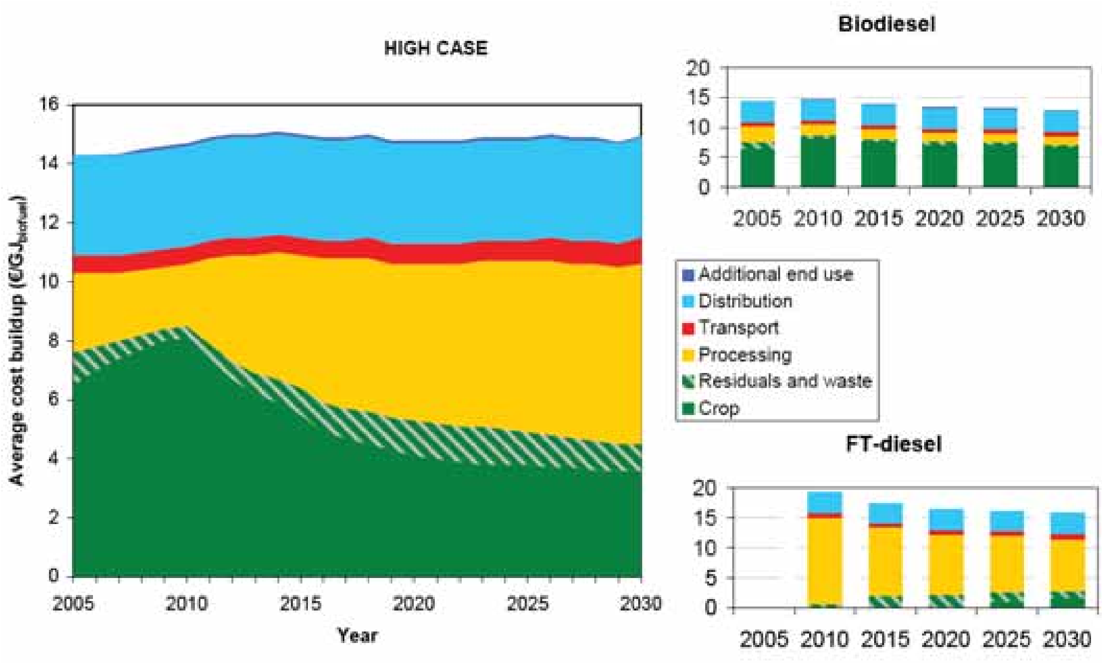
Source: REFUEL (2008)

The key message of Figure 5.15 is that the price of a biomass fuel depends on the level of supply/demand, and that the relationship between price and supply will migrate with time (the charts above assume that more land will become available to produce biomass fuels). The costs are forecast to rise over time, on the assumption that demand for woody biomass will increase somewhat faster than supply.

Non-woody biomass (transport biofuel) costs are derived from the REFUEL report[16]; the figure below shows the evolution over time of the different components of biofuel costs. The delivered costs are expected to stay flat, since falls in fuel costs from the development of second generation biofuels are offset by increased processing costs for the same.

16 REFUEL, 2008a, *Biomass Resources Potential and Related Costs*

Figure 5.16: Average transport biofuel costs over time (high demand scenario)



Source: REFUEL, 2008

Fuel costs for bio-residues depends on the nature of the residue – on whether there are regulatory constraints to disposing of the by-product, and whether there are competitive markets for the by-product. In some cases, users of the bio-residue can be paid a gate fee to take the product off the producer's hands. A summary of the fuel costs is presented in Table 5.7 below.

Table 5.7: Fuel cost for biomass energy in 2010, 2020 and 2030 in €/GJ

Fuel cost, €/GJ	2010	2020	2030
Woody biomass	2.3	2.5	3.0
Non-woody biomass	7.5	4.5	4.0
Bio-residues	0	0	0
Biogas	0	0	0

Sources: REFUEL 2008

5.2.5 Weighted import dependence

As noted above, at present the majority of Ireland's biomass fuel is indigenous. The exception to this rule is biofuels for transport, where almost 50 per cent of fuel was imported in 2007. The proportion of imports might need to rise for this and other biomass fuel types as renewable energy targets become increasingly challenging. However, we assume here that the proportion of imported biofuel remains constant into the future.

5.3: Biomass in the energy system

5.3.1 Delivered energy cost

The difficulties faced when estimating the fuel cost for different biomass categories above is magnified when considering the delivered cost of energy. Firstly, because fuel cost contributes to delivered cost and, secondly, because of the range of different possible conversion technologies. Representative figures for a range of technology and fuel types are included below for each biomass category.

Woody biomass

Table 5.8: Estimates of delivered cost for woody biomass in €/GJ

Woody biomass Delivered cost, €/GJ	Installation type	2010	2020	2030
DTI, 2007	Wood waste, electricity	27-40	25-37	-
DTI, 2007	Woody biomass energy crops, electricity	41-46	39-42	-
DTI, 2007	Woody biomass, co-firing	16-19	16-18	-

Source: As shown in table

Non-woody biomass

Table 5.9: Competitiveness: estimates of delivered cost for non-woody biomass in €/GJ

Non-woody biomass Delivered cost, €/GJ	Fuel	2010	2020	2030
REFUEL, 2008a	Bioeathanol/biodiesel	10-12	10-12	10-12

Source: As shown in table

Bio-residues

Table 5.10: Competitiveness: estimates of delivered cost for bio residues in €/GJ

Bio-residues Delivered cost, €/GJ	Plant type	2010	2020	2030
DTI, 2007	Energy from Waste CHP	26-29	26-29	26-29

Source: As shown in table

Biogas

Table 5.11: Competitiveness: estimates of delivered cost for biogas in €/GJ

Biogas Delivered cost, €/GJ	Fuel	2010	2020	2030
DTI, 2007	Landfill Gas	11-22	11-22	-
DTI, 2007	Sewage gas	10-18	10-18	-
SEI, 2004	Landfill Gas	6-14	9-19	-
BERR, 2008	Landfill Gas	11-13	-	-

Source: As shown in table

5.3.2 Policy and regulation

Planning and building regulations may not be ideally designed for biomass fuels, which can hamper the development of early projects. In addition, biomass is typically less energy dense than fossil fuels, meaning that greater space is required for delivery, handling and storage of the fuel.

Waste regulations affect the handling and disposal of bio-residues, and can present a barrier to exploitation of these sources. Also, recent experience with planned developments in Meath (granted 2008) and Poolbeg shows there is considerable public resistance to energy from waste schemes, which has caused severe delays for these projects.

An ambitious, overarching renewable energy strategy, supported by specific targets, forms the foundation of a highly supportive incentive regime for biomass energy. The REFIT tariffs for biomass and transport biofuel obligations are two of the most significant policy measures.

The Landfill Levy provides an indirect incentive for bio-residues (MSW in particular), and the REFIT is available for the biological fraction of the waste. However, there are no specific incentives encouraging energy from waste.

Methane is a powerful greenhouse gas, so there are strong incentives in place to utilise the waste methane from landfill gas instead of allowing it to escape to the atmosphere. The REFIT scheme includes a tariff for biogas, while the need to comply with waste regulations imposes some regulatory burden, we assume that this is not onerous (compared with alternative forms of energy).

5.3.3 Supply chain and infrastructure resilience

The requirement for a fuel supply chain makes biomass infrastructure more complicated and fragile than most other renewable fuels.

For **woody biomass**, the crop has to be planted, grown, harvested, transported, conditioned and combusted before energy is delivered via electricity networks and/or heat pipes. Dependence on locally grown feedstock makes supply vulnerable to interruption – for example, if an energy crop is affected by blight, a forest afflicted by fire or a local fuel supplier goes out of business.

The fragility of the supply chain will improve as the market in woody biomass develops – for example, by bringing in new suppliers and increasing diversity of supply. However, the infrastructure will remain fragile relative to other renewable energy sources.

For **non-woody biomass** (transport biofuels), the supply chain is complicated by the fact that raw feedstock (e.g. rape seed or sugar cane) is first converted into an intermediate fuel (biodiesel or bioethanol), before transporting to the point of use. Conversion can be a complicated process, particularly for second and third generation biofuels, where the technologies are still under development. This complexity is ameliorated by the fact that the biofuel can be converted into useful energy in a simple, internal combustion engine – one of the most reliable technologies ever invented.

In terms of fragility, the fact that biofuels can leverage the existing petroleum supply infrastructure, coupled with the diversity of potential fuel sources, suggests that the supply infrastructure is robust. On the other hand, reliance on imported biofuel introduces additional risks, including interruptions to shipping or diversion of fuel to the food market. There is also a danger of interruptions to supply caused by the evolving sustainability criteria for biomass – for example, should new research show that a source of biofuel has a high carbon footprint.

The complexity of the infrastructure for **bio-residues** is similar to that for woody biomass – indeed, much woody biomass is clean wood waste, for example from sawmills and paper mills – with some added complications related to compliance with waste regulations.

Biogas is sourced mostly from sewage and landfill. The infrastructure associated with both of these sources is robust and relatively simple, as is the technology required to collect the resource and convert it into useful energy (a simple gas turbine).

5.3.4 Market context in Ireland

Biomass is currently one of the more widely used renewable energy sources in Ireland, accounting for approximately half of total renewable energy supply.

Woody biomass is currently used largely to meet heat demand in the wood processing industry and for domestic heating[17]. A significant amount of additional wood supply is available from forest thinnings and residues from clear-fell sites. Future supplies could grow as a result of increased afforestation, and from improved management of private sector forests.

17 Department of Communications, Marine and Natural Resources (DCMNR), 2007a, *Energy White Paper, Delivering a Sustainable Energy Future for Ireland*

The forest industry in Ireland is well established, and the existing infrastructure could be utilised to fuel biomass electricity plants, though this would bring competition with existing users. Forest thinnings, residues, dedicated energy crops, wood from private forests and clean wood waste (e.g. from construction) could boost the fuel supply, though the relevant supply chains have to be established. Bio-electricity would however compete for this resource with co-firing, heat and CHP – all of which allow for more cheap and/or efficient use of the resource, and are favoured in the current policy framework. For these reasons, the market context for dedicated bio-electricity from woody biomass is relatively weak compared to other renewable options.

Non-woody biomass (biofuels) utilise the existing transport infrastructure and burned are in unmodified car engines. While indigenous biofuel production is increasing, Ireland can tap into an international market for biofuels, as it does for other transport fuels. This means that much of the infrastructure required for delivery is already in place. In the long-term, a move towards electric vehicles would have a negative impact on the market for this fuel.

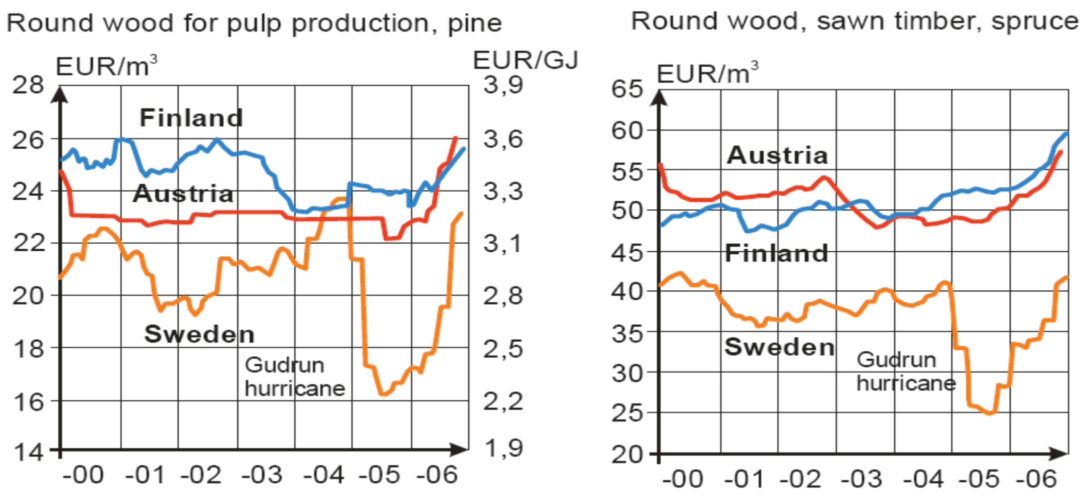
Regarding bio-residues, experience with planned developments in Meath and Poolbeg shows that public resistance to energy from waste schemes is a significant barrier. However, waste is a readily available resource, and the infrastructure to collect it is well established. We assume that technological advances and enhanced public information in this area will improve the future market context for this fuel in Ireland.

The infrastructure for collecting the fuel for landfill and sewage gas and for distributing energy from it (the electricity grid) is well established, and utilised by existing projects. Measures to reduce the amount of waste going to landfill, which aims to direct 80 per cent of biodegradable municipal waste away from landfill by 2016, will reduce the willingness to invest in this resource.

5.3.5 Market volatility

The rapid growth in demand for biomass energy could place pressure on woody biomass supply in the short term. There are a number of alternative markets for wood (e.g. paper of panel board manufacturing), which could have an effect on prices. And finally, yields and thus prices are weather-dependent – Figure 5.17 below shows how wood prices crashed in Sweden in early 2005 following a hurricane. For these reasons, woody biomass gains a relatively low score on market security in 2010 (relative to other technologies), although this is expected to improve as the market matures.

Figure 5.17: Historic round wood prices in Finland, Austria and Sweden



Source: EUBIONET, 2007

The booming global trade in transport biofuels has caused price volatility in recent years, though this is expected to settle down as the market matures. The indigenous nature of bio-residues, and the fact that alternative markets are often limited, means that they score highly in this category. The score does fall through time because of the possibility that implementation of waste policy diverts biomass from incinerators.

Biogas from landfill gas suffers from the same problem to a certain extent, although the slow decomposition of the waste (as opposed to rapid incineration) should bring some stability to fuel supply. Sewage gas should be a very stable and reliable fuel source.

5.3.6 Environmental impacts

The external costs of non woody biomass were studied in Spain by CIEMAT and extended the ExternE methodology to include social externalities. However, this report only examines the environmental (and public health) impacts of this fuel source. The following is a summary of the negative impacts of biomass:

- Soil losses due to the energy crop cultivation were assessed and results showed losses on average of 1.12 t/ha per year, or 10,427 tons per year for the whole area. Damages are caused when the soil is then carried by water, into watercourses and reservoirs, altering water flow and storage capacity. However, the valuation of these effects is quite difficult, because of the complexity of the processes involved. As a first approximation, the cost of sediment removal from reservoirs has been used to estimate the damages caused by erosion, amounting to 0.54 to 1.19 mECU/kWh.
- The amount of fertilisers and pesticides lost by leaching and runoff into ground waters has been estimated to be around 18,073 kgNO_3 and 2,366 kgP per year. Unfortunately, as for erosion impacts, very little information exists on the quantitative impacts that these products may cause in the environment, and so only a valuation for the impact of nitrates in ground waters has been carried out. The resulting figure is 0.08 – 0.8 mECU/kWh.

- The health effects considered have been those caused by atmospheric pollutants, such as particulate matter (PM), SO_2, NO_x, and ozone. For the quantification and valuation of the impacts, the dose-response functions and monetary values proposed by the ExternE Project (EC, 1995) have been used, producing values from 1.93 - 4.55 mECU/kWh.

Table 5.12 presents the cost of environmental externalities associated with the different biomass fuels. These are current estimates, but are taken as constant in real terms over the three timescales – 2010, 2020 and 2030 – and in all scenarios explored (high, medium, low).

Table 5.12: Environmental impact of biomass fuels in €/MWh

	2010	2020	2030
Woody biomass	25	25	25
Non-woody biomass	25	25	25
Bio-residues	25	25	25
Biogas	25	25	25

Source: ExternE 1998: Externalities of Energy, European Commission

5.4: Biomass and Climate change

5.4.1 Carbon content of fuel

The carbon content factors of the different typed of biomass fuels is provided by the IPCC (2006). These are:

- woody biomass – 112 tCO_2/TJ
- non woody biomass – 70 tCO_2/TJ
- bio-residue – 100 tCO_2/TJ
- bio-gas - 54.6 tCO_2/TJ

5.4.2 Lifecycle carbon footprint

Woody and Non-Biomass

Generally the use of biomass at the electricity generation stage is defined as 'carbon-neutral' because the CO_2 released during combustion is absorbed during plant growth. Life-cycle emissions for biomass systems vary substantially depending on the combustion efficiency, power rate, the type of feed (e.g. chips vs. logs vs. pellets vs. gas), as well as other related processes that are energy intensive such as fertilizer and transport.

In Dones' review of GHG emissions of a variety of different heating and CHP plants using different types of wood, it was found that between 3 – 19 g CO_2/MJ (an average of 3 g CO_2/ kWh) were emitted during the entire life cycle analysis. In general, it was found that the difference between wood log and wood chips systems were negligible, while wood pellets had on average higher emissions. This is because the energy required to produce the wood pellets way higher.

A study by Trinity College, Dublin was performed to analyse the life-cycle assessment (LCA) to compare greenhouse gas (GHG) emissions from dominant agricultural land uses, and peat and coal electricity generation, with fuel-chains for Miscanthus and short-rotation-coppice willow (SRCW) electricity in Ireland. It was found that GHG emissions of 1,938 and 1,346 $kgCO_2eq$/ha/annum were produced for Miscanthus and SRWC respectively. In terms of carbon dioxide emitted per KWh, Miscanthus and SRCW fuel chains emitted 131 and 132 g CO_2eq/kWh respectively.[18]

The studies above pertain only to woody biomass and the outcomes are very different as the types of wood studied are vastly different. An average of all the emissions gives a total value of 67.5 g CO_2/ kWh. This value is extended to non-woody biomass.

Bio - residue

Several by-products of farming and food processing industries can be recovered and used in various ways as bioenergy feedstock. These are mainly animal by-products (ABPs) such as meat and bone meal (MBM), tallow, animal manures, food by-products and straw.

18 Trinity College, Dublin, 2007, *Energy crops in Ireland: Quantifying the potential life-cycle greenhouse gas reductions of energy-crop electricity*

The GHG emissions for bio residue are estimated to be 50 g CO_2/kWh, which is the lower estimate for the lifecycle emissions for woody biomass. The value is lower even though they have the same carbon content, because bio residue does not have to be produced explicitly as it is a by product of other processes. The carbon emissions that are expressed are due mostly to construction of plant equipment that will generate electricity and heat for consumer use.

Bio Gas

Biogas has a very low total GHG emissions as it has the lowest carbon content of all the biomasses and because the bio gas is extracted from landfill sites and municipal waste which produce GHG gases purely as a by product of their existence. There is a small carbon impact as not all the gas may be captured and biogas power plants may well run on some fossil fuel to provide some energy for conversion processes to be undertaken. Furthermore, the construction of the site will have to be allocated to the production of electricity or heat over the lifetime, which will also increase the carbon per kWh emitted. The estimate for biomass is therefore 40 g CO_2/kWh.

Table 5.13: Summary of carbon footprint values

	2010	2020	2030
Woody biomass and Non- Woody Biomass Average	3-19 (Dones) 131 (University of Dublin) 67.5 (SQW average)	3-19 131 67.5	3-19 131 67.5
Bio Residue	50 (SQW estimate)	50	50
Bio gas	40 (SQW estimate)	40	40

Source: As cited in table

5.4.3 Supply and infrastructure vulnerability

Climate change will have different effects on the different biomass fuel categories. Most affected is likely to be the non woody biomass (biofuels) in terms of potential damage to crops and logistical supply disruptions. Woody biomass may be impacted to a limited extent in the longer run in terms of damage to some crops. Bio-residues and bio-gas are not likely to be affected by climate change.

5.4.4 Availability change of the resource

Crops grown mostly in southern Europe (such as maize, sunflower, and soya beans) will become more viable further north. There are projections of between 30 to 50 per cent increase in the area suitable for the grain maize production in Europe which includes Ireland. By 2050 energy crops (oilseeds such as rape oilseed and sunflower), starch crops and solid biomass crops (such as sorghum and Miscanthus) show a northward expansion of potential cropping area, but a reduction in southern Europe. However, there is potentially increased crop stress during the hotter drier summers and risk of crops to hail. (IPCC[19])

The increased availability of crops is a direct result of increased temperatures and increased precipitation making the growing conditions marginally improved. These conditions are still arbitrarily determined and the extent to which biomass will actually benefit is uncertain.

19 IPCC, 2001, Contribution of Working Group II to the Third Assessment Report of the *Intergovernmental Panel on Climate Change: Impacts, Adaptation & Vulnerability*

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The Irish Energy Tetralemma

Fuel Report 6: Wind

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel cost	▪ Wind energy is a free renewable resource. ▪ Ireland has an extremely good wind resource,on land but particularly offshore. It is one of the wind-rich countries in Europe.
Delivered energy cost	▪ Currently, the levelised cost of wind energy is relatively high and much less competitive than that from fossil fuels. Offshore wind has a markedly higher capital cost component but this tends to be offset typically by a larger scale of installed capacity. ▪ The delivered cost of wind power comprises capital costs (of developing and installing a wind farm) and operation & maintenance costs (of running the wind farm). ▪ Bottlenecks in the manufacture and supply of wind turbines have prevented significant capital cost reductions from being realised to date. ▪ Cost reductions are expected in the delivery of onshore and offshore wind over the period 2010 to 2030 as a result of technological and grid infrastructure improvements and a more widespread reliable manufacturing base. ▪ Similarly, wind is expected to see considerably improved market conditions where investors are willing to develop and operate capacity mainly due to policy and regulatory support under the banner of renewable energy across Europe and the security of supply imperative, which will significantly improve its competitiveness.
Policy & Regulation	▪ The major regulatory barriers associated with wind energy in Ireland are difficulties in gaining planning consents and grid connections. It is likely that these barriers will remain and may increase for onshore wind as deployment increases and available grid capacity fills up. However, it is expected that these barriers will fall between 2010 and 2030 for offshore wind as the permitting, licensing and planning consent regime matures for that sector. ▪ Onshore and offshore wind developments both benefit from the feed-in tariffs available to electricity suppliers under the REFIT scheme. ▪ Wind is expected to benefit from the significant policy and regulatory support for renewables in general, both at the EU level (the Climate and Energy Package) and national level (the Irish Energy White Paper objectives).

Market context in Ireland	▪ Ensuring that the grid can accommodate additional onshore capacity and a large increase in offshore generating capacity will be key to maintaining a vibrant wind energy sector in Ireland.

Security of supply

Import dependence	▪ Wind is an indigenous resource and as such Ireland is not dependent on import. ▪ Wind constitutes 1 per cent of the national energy mix (and contributes over 70 per cent of electricity from renewables).
Fuel place of origin	▪ This is an indigenous energy source to Ireland.
Supply and infrastructure resilience	▪ The infrastructure associated with onshore wind is robust and uncomplicated with no fuel supply chain and generating equipment that conforms to a relatively straightforward design. ▪ Infrastructure for offshore wind is considered relatively more complex than onshore wind due to the specific sea location of foundations and connecting cabling; it is also considered to be more fragile given that it must endure harsher weather conditions.
Market volatility	▪ The technology supply market is currently volatile due to a very high demand which cannot be met. This is expected to ease off in the next couple of decades with supply naturally catching up with demand and in the presence of both favourable commodity markets (high prices making wind more competitive) and supporting policy framework (promoting renewables). ▪ There is no fuel market associated with wind energy.
Energy availability and intermittency	▪ Wind is among the most intermittent renewables. ▪ The availability of wind resources is site specific. ▪ The average capacity factor (the ratio of actual output over a period of time and its installed maximum output) of wind turbines is approximately 27 per cent for onshore and 30 per cent for offshore wind. ▪ Whilst improvements in both onshore and offshore wind technologies are envisaged up to 2030 it is expected that capacity factors of offshore wind turbines will experience a greater increase as operational experience is gained and offshore equipment and maintenance regimes become more robust.

Sustainability

Fuel longevity	▪ Wind is a renewable energy resource which will be available indefinitely.
Environmental impact	▪ The externality cost of wind energy is among the lowest of all fuels (1.5 €/MWh). ▪ The main impacts that cause public concern are typically associated with noise and visual intrusion. There are also potential ecological impacts (on birds and sensitive terrestrial ecosystems) and possible effects on radio communications. Cumulative impact is also of increasing consideration.

Climate change

Carbon content	▪ Wind as an energy source is carbon free.
Lifecycle carbon footprint	▪ Wind energy has the lowest carbon footprint of all fuels (14-19 gCO_2/KWh). ▪ Emissions arise primarily from raw material extraction, component manufacture, transportation, and construction and dismantling of facilities. In practice, most of the carbon emissions arise at the turbine production and plant construction stages, where there is a requirement for the production of steel for the tower, concrete for the foundations and epoxy for the rotor blades. There are virtually no emissions attributable to the operations of a wind farm.
Supply and infrastructure vulnerability	▪ Depending on the degree of climate change, wind is a relatively vulnerable technology. ▪ More frequent and more intense storms are likely to result from climate change. Whilst wind turbines are designed to shut down over certain wind speeds (in order to prevent damage to the machines) this could occur more frequently (reducing efficiency) in addition to increased incremental damage to the wind turbine structure over shorter periods of time. ▪ Higher wind speeds in the winter and lower in the summer may reduce power output through increased shut down periods in the winter and lower generation in the summer.
Availability change	▪ Wind is expected to increase overall, particularly offshore wind.

6.1: Wind energy: the basics

Wind is a renewable energy source resulting from convection heating within the atmosphere. Winds at a global scale are driven by two main forces: the temperature difference between the poles and the equatorial regions draws cool air towards the equator, and the Coriolis force arising from the Earth's rotation deflects the winds, resulting in familiar storm patterns – clockwise in the northern hemisphere, anticlockwise in the southern hemisphere.[1]

Winds at a local scale are affected by local topography and geography: the different thermal properties of land and sea cause regular *land* and *sea breezes* in coastal areas, differential heating of mountain peaks and slopes throughout the day lead to *mountain* and *valley breezes* and the wind near ground level is shaped by friction with the Earth's surface, and can be strongly affected by the obstacles such as trees and buildings.

Wind has been used to provide energy for humans for generations, from sailing ships transporting goods and people to windmills providing mechanical work. The first windmill to produce electricity was built in Scotland in July 1887; but it is only in the past 30 years that a multi-billion dollar wind power industry has started to develop throughout the world after deployment of the first commercial wind turbines in the 1980s.

Most modern wind generators use three blades, the best compromise between the highest efficiency possible (one blade) and the balance that comes with multiple blades. The blades rotate around a horizontal hub. Together, the blades and the hub are termed the rotor, which is the collector of the system, intercepting winds that pass by. The hub is connected to a gearbox and generator, which are located inside the nacelle. The nacelle is the large part at the top of the tower where all the electrical components are located.

Electricity is generated by wind turbines as the rotating blades convert the wind's kinetic energy into rotational momentum. The rotor turns an alternator, which generates the electricity.

The amount of power that can be harnessed from wind turbine depends on:

- Average annual wind speed; and
- Location, topography, and obstacles.

The theoretical maximum energy which a wind turbine can extract from the wind blowing across it is just under 60 per cent, known as the Betz limit.[2]

Wind turbines start operating at wind speeds of 4 to 5 metres per second (around 10 miles an hour) and reach maximum power output at around 15 metres per second (around 33 miles per hour). At very high wind speeds, i.e. gale force winds, (25 metres/second, 50+ miles/hour) wind turbines shut down.

The power output of wind turbines is proportional to the cube of the wind speed when a turbine operates at the Betz limit (i.e. the power efficiency of the rotor is 60 per cent). This

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1 Danish Wind Energy Association, 2003

2 British Wind Energy Association, 2008, *Wind energy Frequently Asked Questions*, http://www.bwea.com/ref/faq.html#makeelectricity

means that, if the wind speed doubles then the electricity that can be generated from the wind increases by a factor of eight.

All of the above factors influence where a wind turbine can be located and whether it is economically feasible to install.

6.2: Wind as an energy source

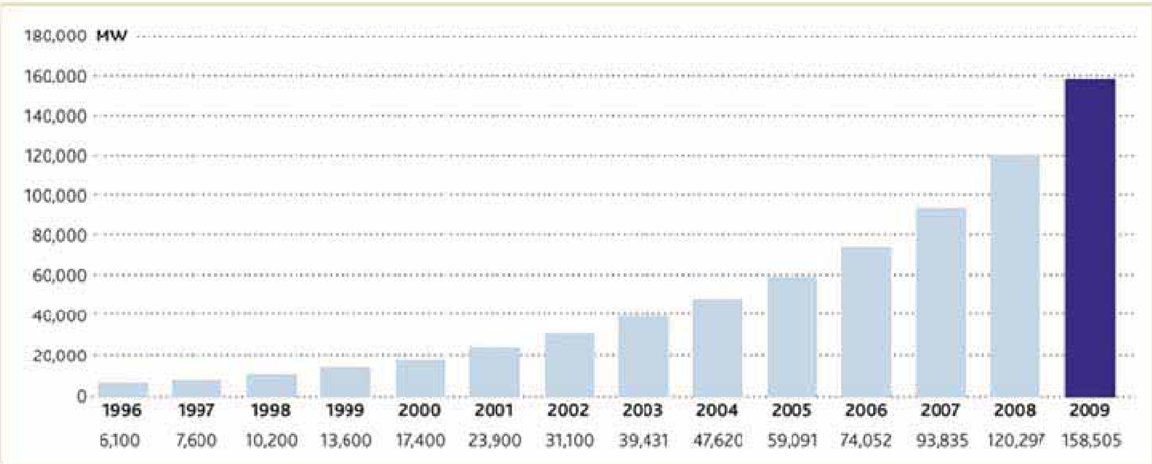
6.2.1 Global availability and harnessing

Wind is a renewable energy source which will be available indefinitely. A recent study has estimated that, globally, there are sufficient locations with sustainable winds at an annual average speed of over 6.9 metres per second to produce approximately 72 terawatts per annum and the authors noted that capturing even a small fraction of that energy could provide the 1.6-1.8 terawatts that made up the world's electricity usage in the year 2000[3].

However, whilst this theoretical global resource is immense, the practical resource (i.e. the amount that can be harnessed after consideration of geographical, physical and social barriers) is significantly reduced. The UK Carbon Trust has estimated the total practical wind energy resource to be between 40,000 and 73,000 TWh per year.[4]

As shown in Figure 6.1 below, cumulative global capacity has experienced growth of over 25 per cent per annum for the last 2 years and exceeded 150,000 MW by the end of 2009.

Figure 6.1: Cumulative installed global capacity growth 1996 -2009



Source: GWEC, 2009

While wind power is currently enjoying a global boom, planning restrictions can inhibit the development of sites on land. This has lead to increased interest in offshore wind energy in recent years. The offshore environment can bring the advantages of steadier, stronger winds; in some cases turbines can be located close to the demand – for example, in estuaries near cities. However, it brings disadvantages associated with the harsh marine environment, such as increased deployment and operation and maintenance costs. Figure 6.2 below shows some of the key milestones in the development of the offshore wind industry in Europe, up to 2007.

3 Archer and Jacobsen, 2005

4 Carbon Trust, 2003, *Building Options for UK Renewable Energy*

Figure 6.2: European offshore wind farm development (up to 2007)

Area	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
European																	
First offshore installation																	
• Vindeby (DK) – 11 x 0.45MW	▲																
First use of Monopiles																	
• Lely (NL) – 4 x 0.5MW			▲														
First large offshore project																	
• Horns Rev (DK) – 80 x 2MW												▲					
Further EU developments[1]																	
• Nysted (DK) – 165.6MW													▲				
• Egmond aan Zee (NL) – 108MW																▲	
• Lillgrund (SWE) – 110MW																	▲

Source: Carbon Trust, 2008

By 2007, 25 offshore wind projects had been developed, many of them large-scale and fully commercial, with a total capacity of around 1,100 MW across five countries (Denmark, UK, the Netherlands, Sweden and Ireland). According to the EWEA, based on planned projects, by the end of 2008 over 80 per cent of the European offshore wind market will be in Denmark and the UK[5].

In the medium term (up to 2015) it is forecast that 10-15 GW of installed offshore wind capacity will be in place in Europe, but delivery within this timeframe will be strongly conditioned by wind turbine availability. It is expected that projects relying on 3.0–3.6 MW machines will not be able to obtain wind turbines before 2009-2010 at the earliest; those planning to use 5 MW wind turbines will have to await the serial production of today's prototypes which are still at the testing stage.

The shape of the European offshore wind market in 2020 has particular significance given the EU targets to source 20 per cent of energy from renewable sources by that date. The EWEA has developed 2 scenarios for 2020 based on a 'minimal effort' and 'high impetus' policy environment; these predict 20 GW and 40 GW of installed capacity by 2020 respectively. The EWEA estimate that, in order to reach 40 GW of installed capacity, there will need to be 7,800 turbines of 5 MW built over 13 years, representing the manufacture of 600 turbines per year, or 50 turbines per month, plus foundations and electrical infrastructure. In addition those turbines have to be assembled, transported and installed on sites.

Wind resource in Ireland

Ireland is one of the most wind-rich countries in Europe and has been identified by the IEA as the EU country with the most economic potential for wind power generation[6].

Ireland's estimated technical wind resource at 75 metres above ground level (being the total theoretical resource constrained by the efficiency of existing wind turbine technology) is 1,015,900 GWh (with 2,040,801 GWh being estimated for 2020). This reduces down to a practical resource of 947,969 GWh (1,902,023 GWh for 2020) after consideration of physical

5 European Wind Energy Association, 2007, *Delivering Offshore Wind Power in Europe*

6 IEA, 2007

constraints and 26,202 GWh (36,701 GWh for 2020) after consideration of the social acceptability of installed wind generating capacity in Ireland[7].

A wind resource map of Ireland is shown in Figure 6.3 below. A recent model of future wind patterns over Ireland showed an overall increase in mean wind speeds for the winter months and a decrease during the summer months (the model was run for a reference period 1961-2000 and future period 2021-2060). The most extreme increases in the mean cube wind speed are expected to arise during February, with increases of about 12 per cent in the north of the country. The overall mean cube wind speed increases by approximately 1.0 per cent over most of the country[8].

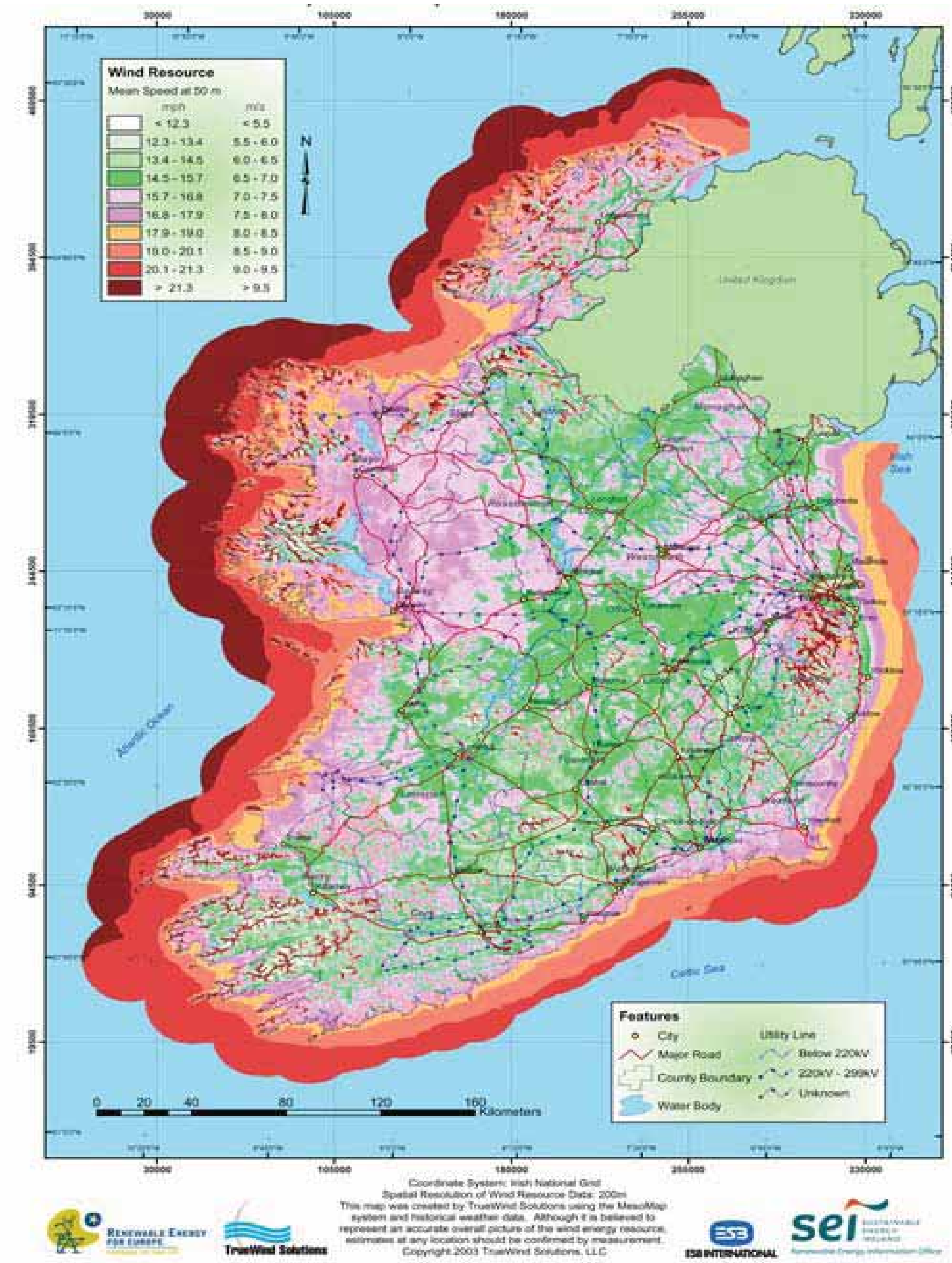
7 SEI ,2004b, *Renewable Energy Resources in Ireland for 2010 and 2020-A Methodology UK Government*. Department of Trade and Industry ,2007, *Impacts of banding the Renewables Obligation-Costs of electricity production*

8 Lynch, P., McGrath, R., Nolan, P., Semmler, T and Wang, S. ,2006, *Ireland's Changing Wind Resource: An Atlas of Future Irish Wind Climatology*, Geophysical Research Abstracts, Vol. 8.

Milborrow, 2004, *Assimilation of wind energy into the Irish electricity network,*

National Offshore Wind Association of Ireland ,2008, http://www.nowireland.ie/offshore-wind-energy-ireland.html

Figure 6.3: Wind speed map of Ireland at 50 metres

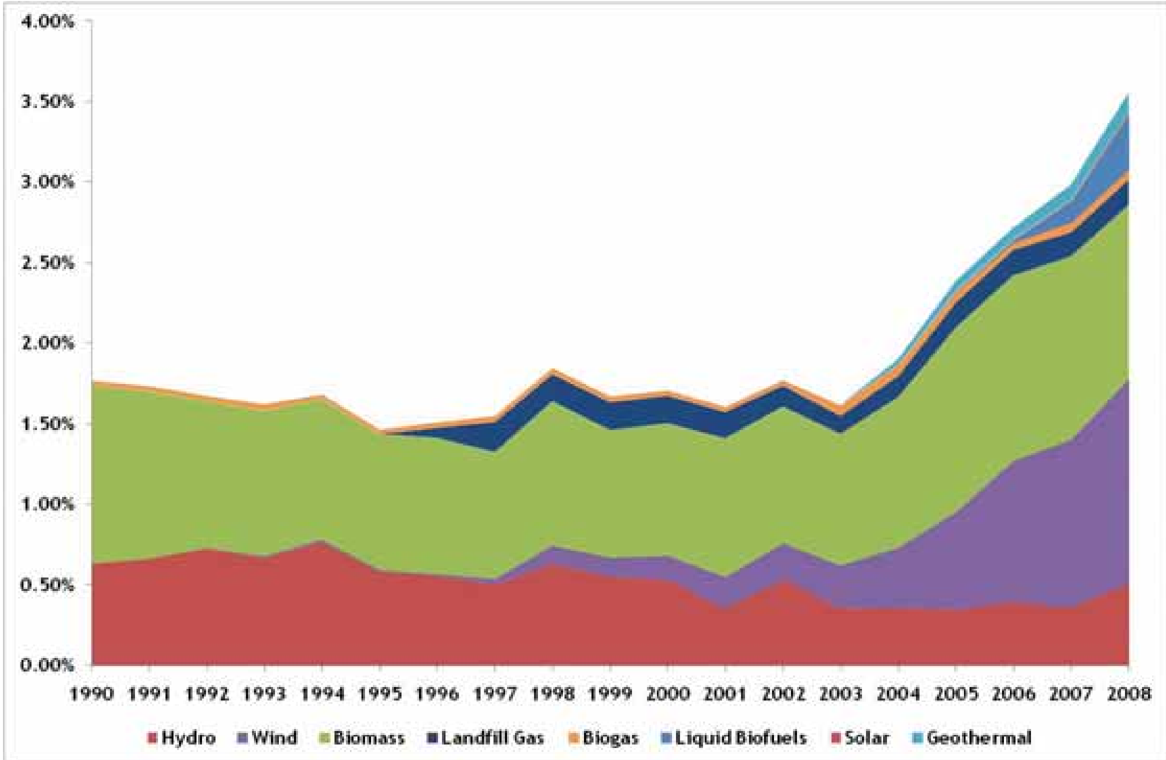


Source: EWEA 'Wind Energy - The Facts' consortium, 2008

6.2.2 Weighted import dependence

Wind is an ambient, indigenous free resource and by its very nature not subject to trade and as such Ireland is not dependent on other countries. In 2007 wind power contributed 1 per cent of Ireland's Total Primary Energy Requirement (TPER). As shown in Figure 6.4 below, this contribution has risen steadily since it was initially included in Ireland's fuel mix in 1992 when the wind farm at Bellacorrick, Co. Mayo came online. By 2007 wind output accounted for 71 per cent of electricity produced from renewable sources[9].

Figure 6.4: Renewable Energy Contributions to TPER



Source: SEI, Energy in Ireland 1990-2008, 2008 report

6.2.3 Energy availability and intermittency

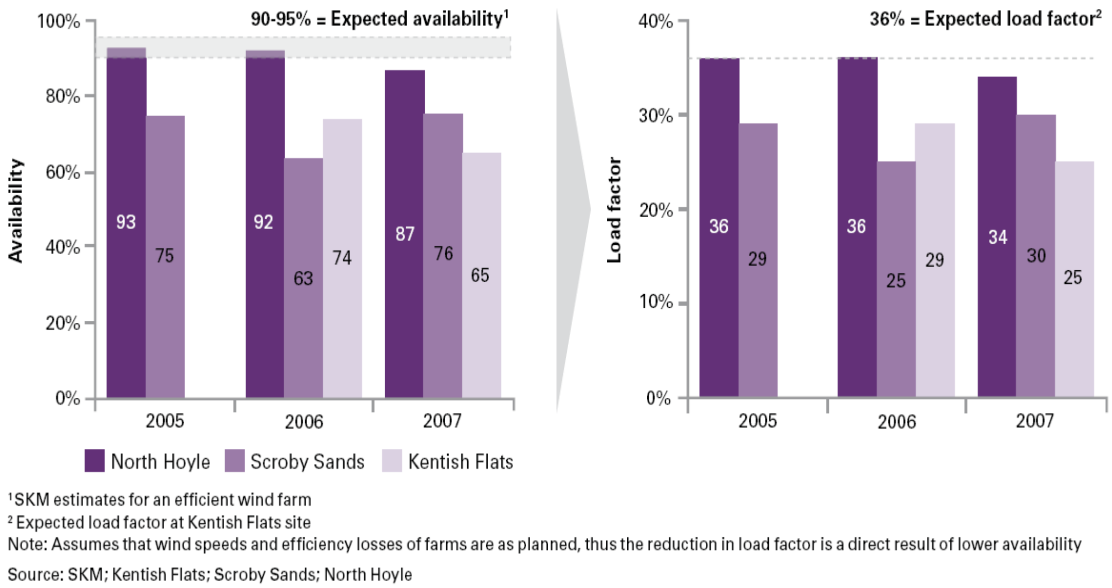
The generation of electricity by wind turbines is dependent on the strength of the wind at any given moment. It is therefore variable, but not unpredictable. Sites are chosen after analysis of local conditions using information from on site anemometer masts to determine wind patterns, including its relative strength and direction at different times of the day and year. This enables a forecast of likely output to be made, information which can be made available to the network operators who are responsible for distributing the electricity.

9 SEI, 2008, *Renewable Energy in Ireland*, 2008 Report

The average capacity factor for Irish onshore wind farms from 2001 to 2007 was 27 per cent according to SEI[10]. We assume that this average rises slightly over time: output from existing wind farms should increase with greater operational experience and as older turbines are re-powered, balanced by an expected increased failure rate of aging turbines, and increasing use of marginal sites with lower wind resource.

The capacity factor for offshore wind should be higher since the wind resource is greater offshore, but this has to be balanced against the probability of longer maintenance delays. Figure 6.5 shows the expected and actual capacity factors achieved at three UK offshore wind farms, and shows a trend of output falling somewhat lower than expectations in the early years of operation.

Figure 6.5: Availability (up-time) and average load factor (capacity factor) for three UK offshore wind farms



Source: Carbon Trust, 2008

It is assumed that Irish offshore wind farms will suffer similar teething problems, but that capacity factors will increase slightly as operational experience is gained and offshore equipment and maintenance regimes become more robust.

Table 6.1 below summarises the energy availability and intermittency scores for wind in 2010, 2020 and 2030.

10 Figure derived by comparing installed wind capacity (from Table 6 of the SEI report) with reported wind output (Table 9 of the SEI report)

Table 6.1: Wind energy availability and intermittency in per cent

Availability, per cent	2010	2020	2030
Onshore wind	27 per cent	28 per cent	30 per cent
Offshore wind	30 per cent	35 per cent	35 per cent

Source: SQW Energy based on literature review

6.3: Wind in the energy system

6.3.1 Wind uptake in Ireland

Onshore wind

A map of existing onshore wind developments by counties in Ireland (as at February 2010) is shown in Figure 6.6 below. The data used to create this map calculates Ireland's total installed capacity to currently be 1,570.1 MW, generated from 124 wind farms in 23 counties[11].

By January 2010 the installed capacity of wind energy had reached 1,264 MW accounting for approximately 11 per cent of total electricity generation in Ireland. Another oppourtunity 5,000 MW of additional wind capacity will need to be installed within the next 10 years if Ireland is to meet the 40 per cent renewable target for electricity generation.

Figure 6.6: Onshore wind developments in Ireland (as at 31st May 2010)

Source: IWEA, 2010

11 IWEA, 2010, *Wind map of Ireland*, http://www.iwea.com/index.cfm/page/windmap

Offshore wind

The first offshore wind farm (Arklow, co-developed by Airtricity and GE Energy) opened in 2004 with a rated output of 25 MW. Arklow is currently operated by GE Energy as a demonstration platform for their 3.6 MW offshore turbines (General Electric, 2004). However, according to Airtricity, Phase II of the project is on hold due to changes in the Irish electricity market; with the expansion of the REFIT scheme they are deciding how best to take the project forward[12].

At present there are 5 companies actively involved in developing offshore wind energy projects in Ireland; these are Airtricity, Oriel Windfarm, Eco Wind, Saorgus and Fuinneamh Sceirde Teoranta. Eco Wind have full consent for a project at Codling Bank, the other companies have projects at various stages in the permitting process. It is estimated that the total capacity of these sites will eventually supply up to 2,000 MW of additional energy into the national grid.[13]

It is the view of the IEA that the current focus of market interest in Ireland is for onshore wind generation. The government has decided that onshore wind requires priority attention since it provides a lower cost solution than offshore wind development (IEA, 2007).

6.3.2 Delivered energy cost

Onshore wind - Capital costs

A breakdown of the split of capital costs associated with onshore wind turbine developments is shown in Table 6.2 below. It can be seen that, whilst the turbine itself accounts for the majority of the total investment costs, there are other significant cost components, including electrical installation and grid connection (the cost of which is highly variable and site-specific). Approximately 75 per cent of total power production costs for onshore wind relate to capital costs. Compared to conventional fossil fuel technologies such as a natural gas power plant, where 40 to 60 per cent of total costs are related to fuel and O&M costs, onshore wind is considered to be capital intensive[14].

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12 Airtricity, 2008, *Offshore Activities*, http://www.airtricity.com/england/wind_farms/offshore/

13 National Offshore Wind Association of Ireland, 2008, http://www.nowireland.ie/offshore-wind-energy -ireland.html

14 European Wind Energy Association, 2008, *Wind Energy The Facts*

Table 6.2: Cost Structure for a Typical 2 MW wind turbine installed in Europe (2006-€)

	Investment (€1000/MW)	Share (per cent)
Turbine (ex works)	928	75.6
Foundation	80	6.5
Electric installation	18	1.5
Grid Connection	109	8.9
Control system	4	0.3
Consultancy	15	1.2
Land	48	3.9
Financial Costs	15	1.2
Road Construction	11	0.9
Total	1227	100

Source: EWEA, 2009

Offshore wind - capital costs

A breakdown of the split of capital costs associated with two offshore wind turbine developments (Horns Rev and Nysted, Denmark) are shown in Table 6.3 below. In comparison to onshore wind, the share of turbine costs as a proportion of total capital cost is significantly lower. This reflects the additional engineering challenges associated with deployment and connection of offshore devices.

Table 6.3: Average investment costs per MW related to offshore wind farms in Horns Rev and Nysted

	Investments	1000€/MW Share (per cent)
Turbines (ex works), including transport and erection	815	49
Transformer station and main cable to coast	270	16
Internal grid between turbines	85	5
Foundations	350	21
Design and project management	100	6
Environmental analysis	50	3
Miscellaneous	10	<1
TOTAL	1680	~100

Source: EWEA, 2008

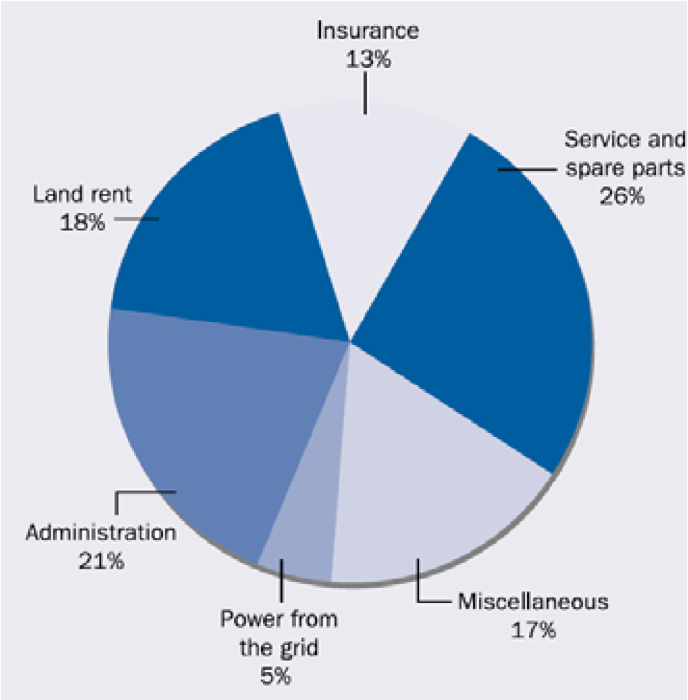
Operation and maintenance costs

Operation and Management (O&M) costs can be split into the following cost components:

- Insurance;
- Regular maintenance;
- Repair;
- Spare parts;
- Rent; and
- Administration.

An overview of the estimated split between O&M cost categories for onshore wind is shown in Figure 6.7 below.

Figure 6.7: O&M Costs for wind turbines as an average over the Period 1997-2001 (Germany)



Source: EWEA, 2008

Typical O&M cost estimates are €45-70/MW/yr for an onshore wind farm and about 60 per cent higher for an offshore wind farm[15].

Back-up supply costs

A 2006 study by the UKERC[16] concluded that, although the output from fossil fuel power stations will need to be adjusted to cope with fluctuations in wind power output, the adjustment would be small and would have no significant effect on wind's contribution to CO_2 savings. UKERC estimated that, if wind power were to supply 20 per cent of the UK's electricity, the cost to electricity consumers of handling its intermittency would be 0.1p (0.115 €c) per kWh. The report included a graph indicating the range of cost estimates for back-up electricity supplies from a number of other studies, with points 89[17] and 125 [18] on the graph representing data for Ireland, see Figures 6.8.

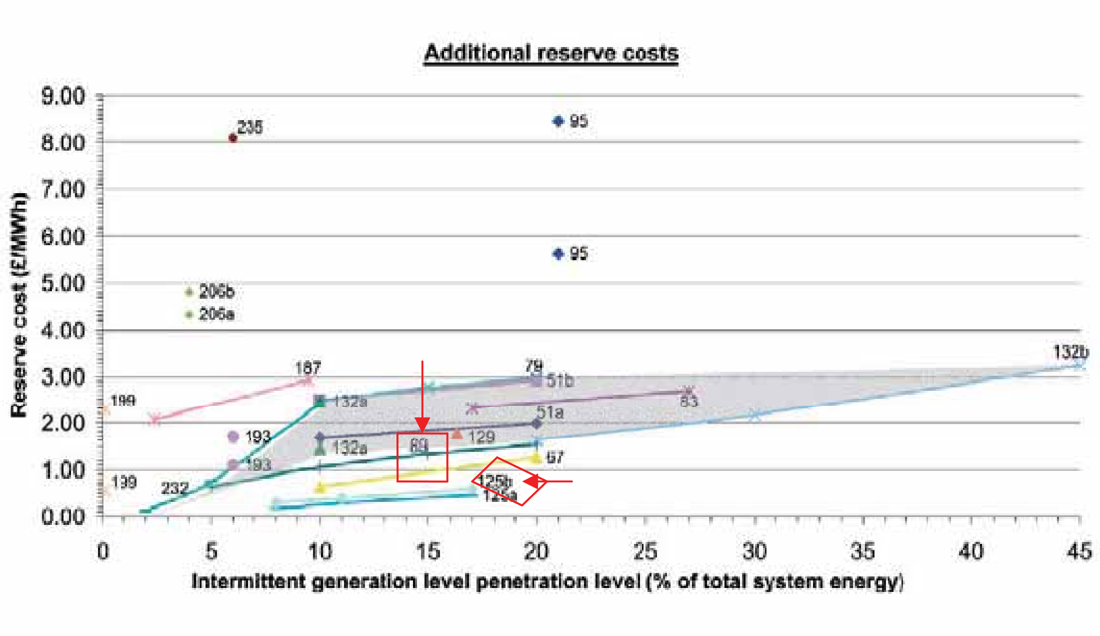
15 UK Government, Department of Trade and Industry ,2007, *Impacts of banding the Renewables Obligation – Costs of electricity production*

16 UK Energy Research Centre

17 Milborrow, 2004, *Assimilation of wind energy into the Irish electricity network*

18 SEI, 2004a, *Operating Reserve Requirements as Power Penetration Increases in the Irish Electricity System*

Figure 6.8: Range of findings on the cost of additional reserve requirements



Source: UKERC, 2006

Levelised Costs

Levelised costs for onshore wind fell in the early years of the millennium as designs improved and efficiencies of scale were realised, with increases in both the number and size of turbines in production. However, this trend has reversed in recent years, reflecting a rise in the cost of basic materials (e.g. the steel used in turbine towers, concrete in the foundations and the energy involved with manufacturing and transporting the components) and a shortage of capacity in supply chains faced with a rapid increase in global demand. Bottlenecks in supply have pushed out turbine delivery dates and pushed up prices for new orders.

Whilst the supply situation remains tight, costs should start to fall as inflation in raw materials subsides and as new manufacturing capacity (commissioned in response to the high prices) comes on-stream.

Figure 6.9 below shows the consequences for wind power production costs of the very rapid increase in wind power capacity in recent years. It is based on the following assumptions of the EWEA 'Wind Energy – The Facts consortium[19]:

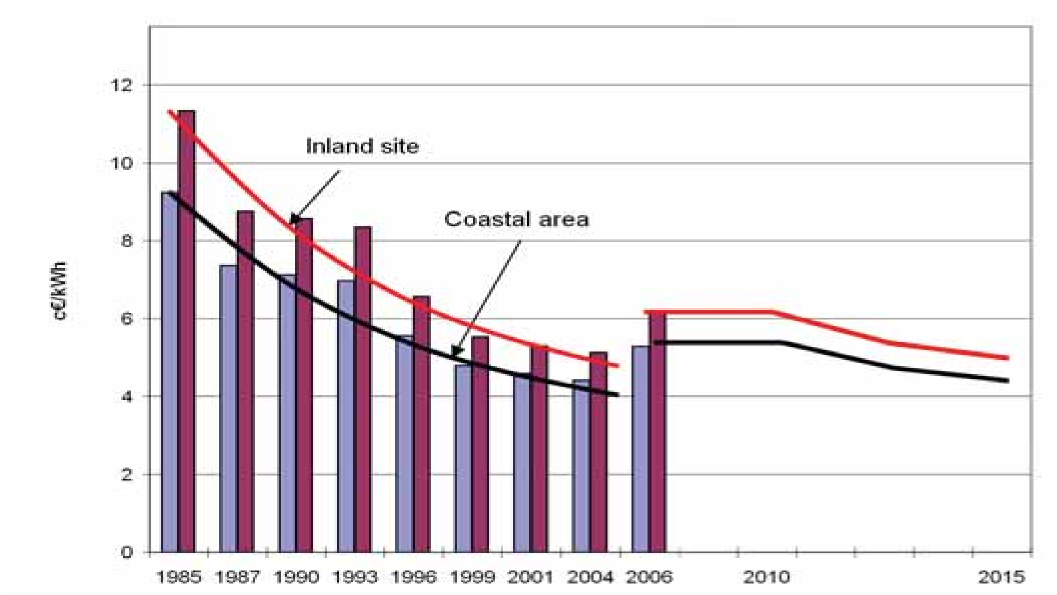
- the present price-relationship should be retained until 2010 with no price reductions foreseen due to a persistently high demand for new wind turbine capacity, and sub-supplier constraints in the delivery of turbine components;
- from 2010 until 2015, a learning rate of 10 per cent is assumed, implying that each time the total installed capacity doubles, the costs per kWh of wind generated power decreases by 10 per cent; and

19 This project is financed by the Intelligent Energy Europe programme of the Executive Agency for Competitiveness and Innovation

- the growth rate of installed capacity is assumed to double the global cumulative installed capacity every three years.

The curve (see Figure 6.9) illustrates cost development in Denmark, where onshore wind development costs are relatively low. Thus, the starting point for the development is a wind power cost of around 6.1 c€/kWh for an average 2 MW turbine, sited at a medium wind regime area (average wind speed of 6.3 m/s at a hub height of 50 m). The development for a turbine in a coastal location is also shown.

Figure 6.9: Using experience curves to illustrate the future development of wind turbine economics until 2015



Source: EWEA, Wind Energy – The Facts Consortium, 2008

There are a number of sources of information on average levelised costs for onshore wind energy based on a number of assumptions around wind resource, location, turbine efficiency, project life, financing costs, discount rate etc. A summary of some of the existing levelised cost data is provided in Tables 6.4 and 6.5 below.

Table 6.4: Current estimates of levelised costs for wind energy

Source of estimate (year)	Onshore (€/ GJ)	Offshore (€/ GJ)
IEA (2005)	7-21	
SEI (2004b)	14 (10MW installation) 13 (50MW installation)	18 (200MW installation)
UK DTI (2007)	21 - 35	28 - 35
UK BERR (2008)	17 - 34	24 - 49
Carbon Trust (2008)		28 - 41
EWEA, 2008	11-25	17 - 26

Source: as shown in table

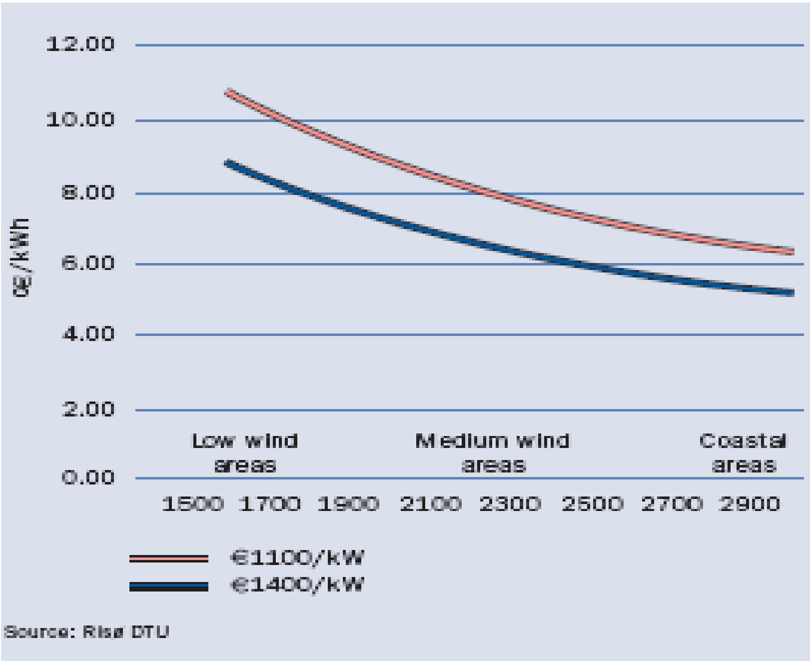
Table 6.5: Future estimates of levelised costs for wind energy

Source of estimate (year)	Onshore (€/ GJ)		Offshore (€/ GJ)	
	2010	2020	2010	2020
UK DTI (2007)	22 - 37	21 - 35	28 - 35	26 - 33
Carbon Trust (2008)				21 - 33

Source: as shown in table

In Figure 6.10, the costs per kWh wind power are shown as a function of the wind regime and the discount rate, where the latter ranges between 5 and 10 per cent.

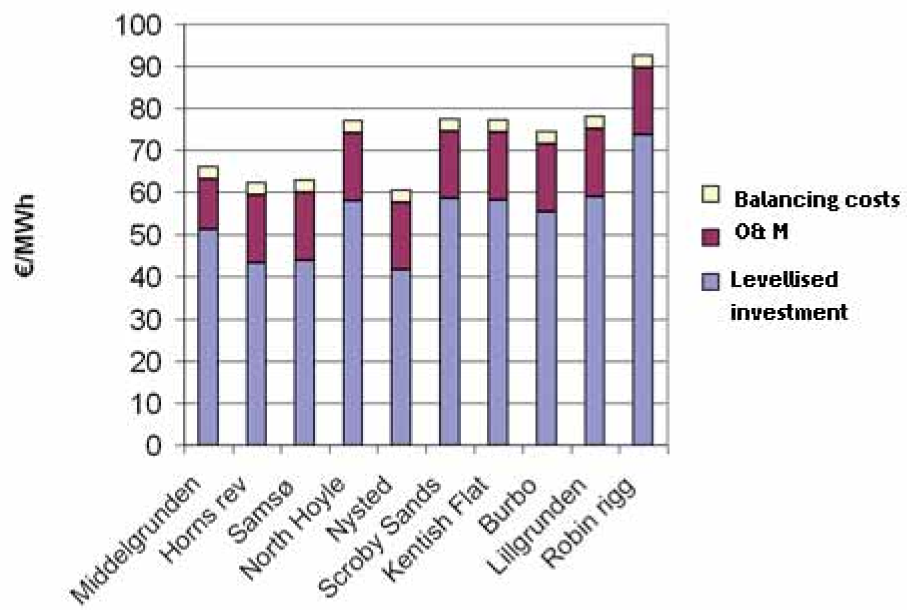
Figure 6.10: Calculated costs per kWh of wind generated power as a function of the wind regime at the chosen site (number of full load hours)



Source: EWEA, 2009

Figure 6.11 shows the total calculated costs per mWh for a selected number of offshore wind farms. Total production costs differ significantly related partly to the depth of the sea and distance to the shore and partly to increased investments costs in recent years.

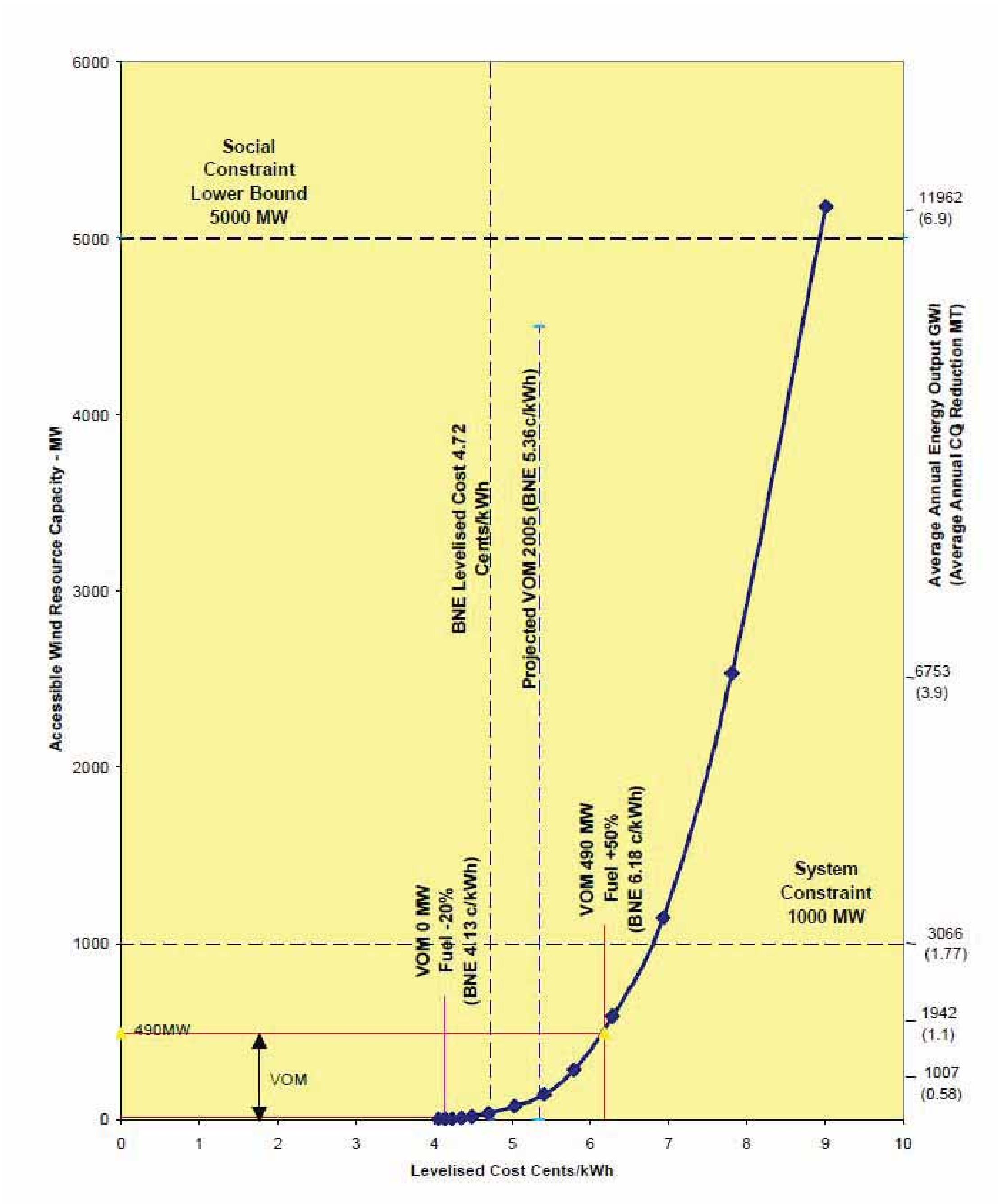
Figure 6.11: Calculated energy production costs for selected offshore wind farms (2006-prices)



Source: EWEA, 2008

SEI have constructed resource/cost curves that project the levels of resource that are accessible as levelised cost for onshore wind increases in 2010 and 2020 (see Figures 6.12 and 6.13). A significant conclusion drawn from this work was that wind energy has the potential to compete in terms of cost with fossil fuel electricity generation by 2010 and its cost competitiveness is projected to increase over the period to 2020 depending on the rate of capital cost reductions and on gas price increases.

Figure 6.12: Resource Cost Curve: Wind Generation 2010 at 2004 Prices (8 per cent Discount)

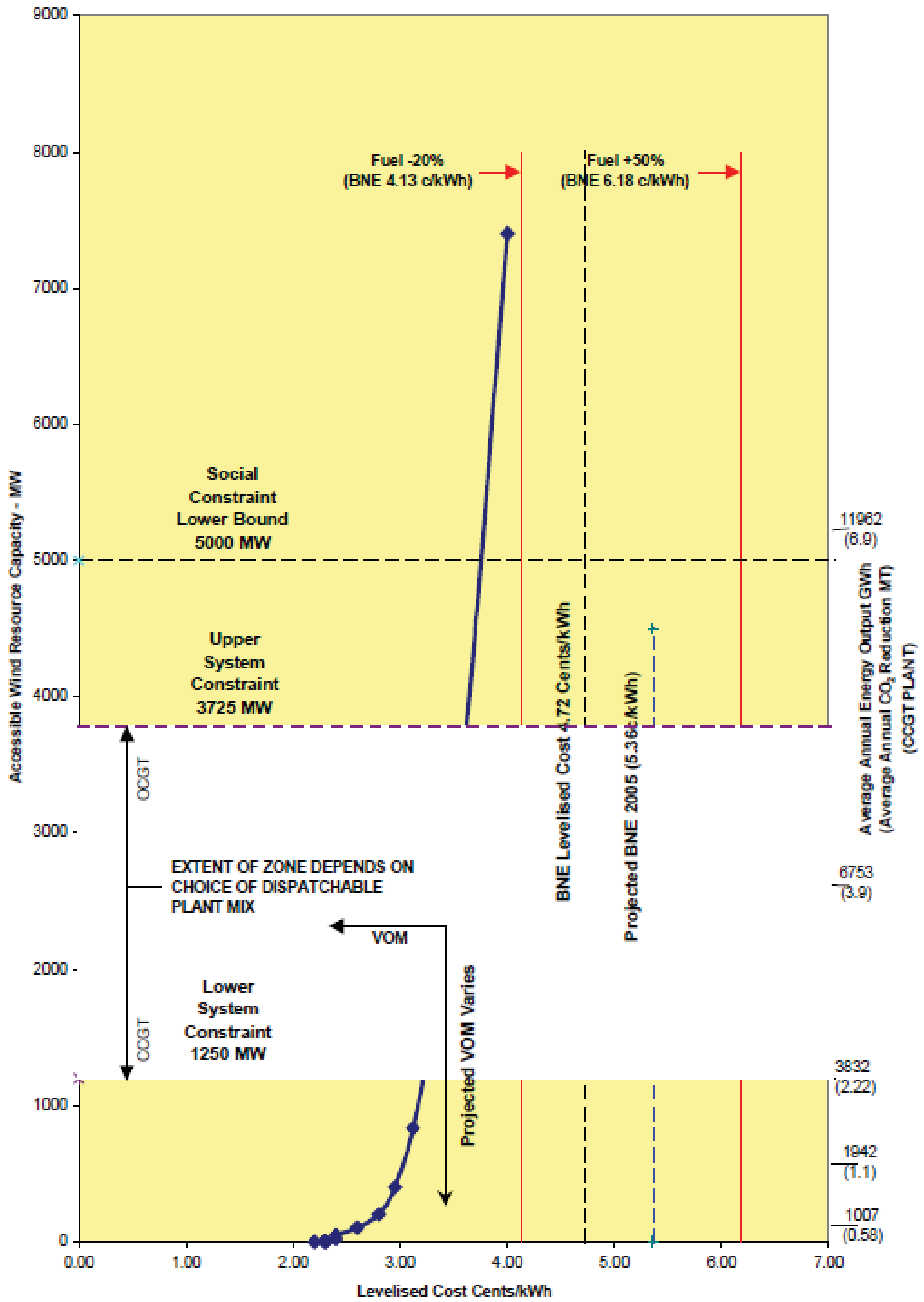


Source: SEI, 2004b[20]

20 SEI, 2004b, *Renewable Energy Resources in Ireland for 2010 and 2020 – A Methodology*.

UK Government, Department of Trade and Industry,2007, *Impacts of banding the Renewables Obligation – Costs of electricity production*

Figure 6.13: Resource Cost Curve: Wind Generation 2020 at 2004 Prices (8 per cent Discount)



Source: SEI, 2004b[21]

21 SEI ,2004b, *Renewable Energy Resources in Ireland for 2010 and 2020 - A Methodology*

6.3.3 Wind – Conversion Technologies

It is widely recognised that further technology developments are required in order to exploit more resource opportunities and bring down the costs of wind power.

Onshore wind

Over the years many different turbine designs have been explored. However, the vast majority of commercial turbines now operate on a horizontal axis with three evenly spaced blades. These are attached to a rotor from which power is transferred through a gearbox to a generator (although some turbine designs avoid a gearbox by using direct drive). The electricity is then transmitted down the tower to a transformer and eventually into the grid network.

Since the arrival of the first commercial wind turbines in the 1980s their size has grown by a factor of 100, with rotor diameters increasing eight-fold, see Figure 6.14. The average capacity of turbines installed around the world during 2007 was 1.5 MW[22].

Some of the key areas of research that have been identified as potential routes to the development of commercial wind turbines with an output of up to 10 MW are as follows[23]:

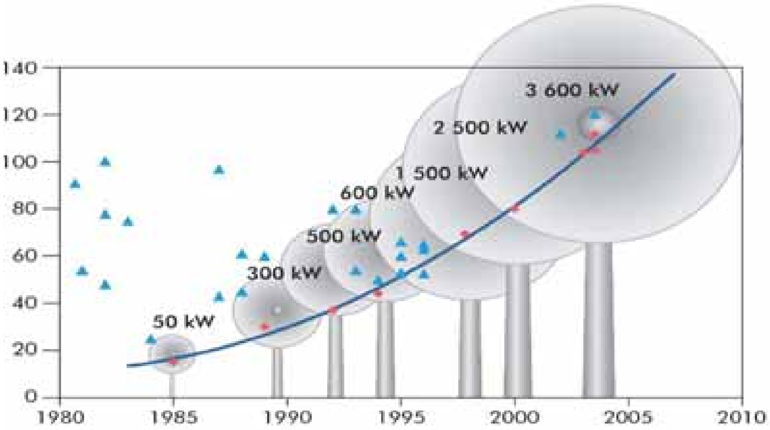
- **Superconducting generators.** Research is underway in developing a generator based on high-temperature superconducting materials that could be used in a 10MW turbine with a 50-60 per cent reduction in weight and size based on existing models.
- **Smart rotors.** These blades would alleviate the load by applying load control devices that do not affect reliability or maintenance needs.

A novel concept also identified by the IEA is “flying windmills” where turbines are tethered to the ground and take advantage of jet stream wind currents. These would have the advantage of tapping into constant wind resources without the need for towers but carry associated hazards in terms of the cabling and rotors and other problems associated with competition for air space and implications in bad weather.

22 Global Wind Energy Council , 2008, *Global Wind Energy Outlook 2008*

23 IEA ,2008, *Energy Technology Perspectives*

Figure 6.14: Turbine size trends 1985-2005



Source: German Wind Energy Institute (GEWI) 2006

Offshore wind

Offshore wind turbines are generally large-scale, marinised versions of onshore turbines with rated outputs between 3 and 5 MW, although larger turbines of up to 7.5 MW are being developed, as are offshore-specific turbines. Installation is currently achieved using standard jack-up barges and custom-built vessels that limit operation to water depths of around 35m. The foundations of existing commercial turbine designs are limited to up to 30m water depth[24].

Future technology improvements

Improvements in offshore wind turbines are likely to be in areas such as reliability, grid compatibility, acoustic performance (noise reduction), maximum efficiency and productivity at low wind speeds.

Regarding offshore wind, additional technology improvements and economies of scale are required to increase reliability, to enable development of sites that are further from shore and in deep water and to deliver cost reductions. Current areas of technological interest include:

- Foundation designs that suit deeper water conditions and larger, heavier turbines.
- Improving the technology within the cables and connections between turbines and the onshore electricity grid, including a move from High Voltage Alternating Current (HVAC) subsea cables to High Voltage Direct Current (HVDC) transmission.
- Developing cost-effective floating installation techniques for deep water.
- Optimising installation techniques for higher volumes and speeds.
- Finding technologies that allow access and repairs to take place in worse weather conditions than is currently possible.

24 Carbon Trust ,2008, *Offshore wind power: big challenge, big opportunity*

A number of offshore wind research and development projects that hope to improve the technology in the future have been identified [25].These include:

- **Floating Platforms.** This concept may be of interest where load centres are located near deepwater sites. However, the cost of transmission and the floating foundations may be a barrier to the uptake of the technology.
- **Hybrid wave and wind turbines.** These would consist of floating offshore wave energy devices that act as foundations for offshore wind turbines.

Turbine manufacturers seem wary of investing in any new technologies in the medium term due to the increased risks and costs associated with designing new turbines. It is therefore considered unlikely that offshore wind technology will change dramatically before 2020[26].

6.3.4 Policy and regulation

All wind energy development projects which require planning permission must comply with the applicable planning regulations. Planning permission in Ireland expires after a set period of time, usually five years, which has become a cause of concern for some developments due to the delays in obtaining grid connections. Since 2006, applicants for new planning permissions have been advised to include a request for a planning decision valid for ten years rather than five.

It is assumed that difficulties in gaining planning consents and a grid connection increase for onshore wind as wind deployment increases and available grid capacity fills up, but fall for offshore wind as the permitting, licensing and planning consent regimes mature for that sector.

The Irish National Climate Change Strategy includes an aim for 15 per cent of electricity to be generated from renewable sources by 2010 and 33 per cent by 2020.[27] These targets are re-iterated in the 2007 Energy White Paper[28]. Increased use of wind energy in the electricity fuel mix is seen as a primary route to achieving these targets. In their 2007 review of energy in Ireland the IEA noted that electricity generated from renewables contributed 7.5 per cent to electricity supply in 2005, up from 5.5 per cent in 2004; this was achieved primarily by a 70 per cent rise in electricity generated from wind-powered plants following the removal of grid connection restrictions[29].

Onshore wind benefits from a strong incentive regime, underpinned by REFIT tariff subsidies available to suppliers of electricity generated from renewables. In February 2008 DCENR announced that offshore wind would also receive support under the REFIT. During its first

25 IEA, 2008, *Energy Technology Perspectives*

26 Carbon Trust, 2008, *Offshore wind power :big challenge, big opportunity*

27 Department of the Environment, Heritage and Local Government, 2007, *Ireland National Climate Change Strategy 2007-20*

28 Department of Communications, Marine and Natural Resources, 2007, *Delivering A Sustainable Energy Future For Ireland*

29 IEA, 2007, *Energy Policies of IEA Countries - Ireland 2007 Review*

year (2006), 98 per cent of all the REFIT support was allocated to electricity generated from onshore wind farms[30].

6.3.5 Supply chain and infrastructure resilience

Both onshore and offshore wind benefit from an uncomplicated energy delivery infrastructure: neither depends on a fuel supply chain, and the generating equipment is relatively straightforward and common to both environments (assuming HVDC connections are not required, for example, for farms located far offshore).

The infrastructure associated with onshore wind is relatively robust: the distributed nature of the resource (both within a farm and between different sites) means that there is no single point of failure, and any issues with, for example, individual turbines or the connection to the grid can relatively easily be accessed and rectified.

Offshore wind infrastructure is similar to onshore in many respects. However, access to an offshore wind site or connecting cable depends on suitable weather conditions. Equipment is most likely to fail in bad weather, leading to potentially long delays during which output is curtailed or shut off entirely.

6.3.6 Market context in Ireland

As mentioned in other parts of this report, at present, a failure to align planning regulations with grid connection timelines is having an adverse effect on the rate of development of the wind energy sector in Ireland as planning consents can expire before grid connections agreements are put in place.

Another issue highlighted by the Irish Wind Energy Association is that by capping the REFIT tariff at 1,500MW there is little capacity left available for projects that have not yet received connection offers (it is estimated that there is 3,000 MW currently being processed for connection offers). Therefore, developers in the application process who do not know what support will be available to them once they are up and running face considerable uncertainty[31].

6.3.7 Market volatility

The absence of a fuel supply chain makes wind a relatively secure source of energy. However, in the short term, the supply chain bottlenecks mentioned previously in this chapter severely restrict the availability of turbines in the period to 2010.

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30 European Wind Energy Association , 2008, *Wind Energy – The Facts*

31 IWEA ,2008b, *Current Issues*, http://www.iwea.com/index.cfm/page/currentissues

Lynch, P., McGrath, R., Nolan, P., Semmler, T and Wang, S. 2006, *Ireland's Changing Wind Resource: An Atlas of Future Irish Wind Climatology*, Geophysical Research Abstracts, Vol. 8.

Milborrow, 2004, *Assimilation of wind energy into the Irish electricity network*

For this reason, the market security for both onshore and offshore wind is relatively low in 2010, but rises after this point as the equipment supply chain responds to demand.

6.3.8 Environmental impacts

The external environmental cost of wind farms were established as part of the ExternE study in the UK[32]. These are considered to be similar to Ireland and the results of this study are outlined below.

The impacts of wind energy of the greatest public concern in the UK have been noise and visual intrusion. There are also potential ecological impacts (on birds and sensitive terrestrial ecosystems) and possible effects on radio communications. In addition the effects of accidents and emissions from the upstream turbine life cycle on global warming and acidification impacts is of growing consideration.

Noise impacts are usually greatest for the houses closest to the turbines and fall-off rapidly with distance. Using a simple noise propagation model they estimate the noise increment at the nearest house to be 2.6 dB(A), and only 0.03 dB(A) at the nearest village. At these levels the noise increment will generally be indistinguishable from ambient noise levels whenever the wind is sufficiently strong for the turbines to operate. However, effects of terrain may complicate the analysis.

Visual intrusion is the impact of most concern, but is extremely difficult to quantify. Most landscape assessment procedures are essentially qualitative. The only obvious quantitative measure is the zone of visual intrusion. This is unsuitable for marginal analysis and therefore the impact of visual intrusion by assessing impacts of a larger programme in the area, which might have a significant impact on the landscape is considered.

Other issues include electromagnetic (EMF) interference, airline flight paths, land-use, protection of areas with high landscape value, and bird and bat strike. EMF interference, airline flight paths and landscapes with a high aesthetic value are dealt with primarily by applying best practices. Most bird species exhibit an avoidance reaction to wind turbines, which reduces the probability of collision.[33]

In general the impacts on the environment are not large and the average reported for all countries studied is 0.15 EUR-cent/kWh.

32 ExternE ,1998, *Externalities of Energy, European Commission, DGX11*

33 National Environmental Research Institute (NERI), 2004, Annual Status Report, *Investigations of migratory birds during operation of Horns Rev Offshore wind farm*

6.4: Wind energy and climate change

6.4.1 Carbon content of fuel

Wind energy does not have any carbon (or any other chemical) content. Therefore, the value for the Index is 0.0 kgCO_2.

6.4.2 Lifecycle carbon footprint

As wind has no carbon content there are virtually no emissions that arise from the operations of a wind farm (other than from site inspection and operation and maintenance (O&M), which are negligible). Some emissions however arise from the other stages of the life cycle including raw material extraction, component manufacture, transportation, and construction and dismantling of facilities. In practice, most of the carbon emissions arise at the turbine production and plant construction stages, where there is a requirement for the production of steel for the tower, concrete for the foundations and epoxy for the rotor blades. There are different estimates of the proportional impact this stage has on total carbon emissions. The IAEA report that construction and manufacturing account for 72 per cent to 90 per cent of cumulative emissions[34], while others report a figure of 98 per cent[35]. Carbon and other GHG emissions not related to construction and production arise during O&M, decommissioning, transport of materials and turbine, and range between 10 per cent and 28 per cent of cumulative emissions (IAEA, 2006).

A recent study by the IAEA, reports variations between 8 grams of carbon dioxide equivalent per kilo-watt hour (gCO_2eq/kWh) and 30 gCO_2eq/kWh for onshore, and 9 gCO_2eq/kWh and 19 gCO_2eq/kWh for offshore turbines (IAEA, 2006). A report by the UK Parliamentary Office of Science and Technology (POST) observes that in the UK context there is very little difference between onshore (4.64 gCO_2eq/kWh) and offshore (5.25 gCO_2eq/kWh) carbon footprints.

A study by the World Energy Council of UK wind farms found that the life cycle GHG footprint was between 3 gCO_2eq/kWh and 22 gCO_2eq/kWh[36]. The split between this range for onshore and offshore are shown in Table 6.6. Offshore wind ranges from 10 gCO_2eq/kWh to 22 gCO_2eq/kWh, and onshore ranges from 8 gCO_2 eq/kWh to 15 gCO_2eq/kWh. A study of the life cycle greenhouse gas emissions from the power sector in Japan found that emissions over the lifetime were 29 gCO_2eq/kWh; however it is unclear whether this is for onshore or offshore wind power.[37]

To calculate the value used for the 2010 index the average of all the 2006 and 2007 referenced figures are calculated. Minor improvements in technology for producing the wind turbines are taken into account and the carbon emissions are reduced for 2020 and 2030 by a small factor to reflect this. There are no large step reductions in production emissions

34 International Atomic Energy Agency (IAEA), 2006, *A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies*, in Planning and Economics Studies Section

35 UK Parliamentary Office of Science and Technology, 2006, *Carbon footprint of electricity generation*

36 World Energy Council, 2007, *Survey of Energy Resources*

37 IEA,2000, *Implementing Agreement for Hydropower Technologies and Programs* Appendix III: Hydropower and the Environment: Present Context and Guidelines for Future Action

forecasted for this time period. However, offshore wind is projected to have a lower carbon footprint in the future as the technology is nascent and higher degrees of improvement are more likely.

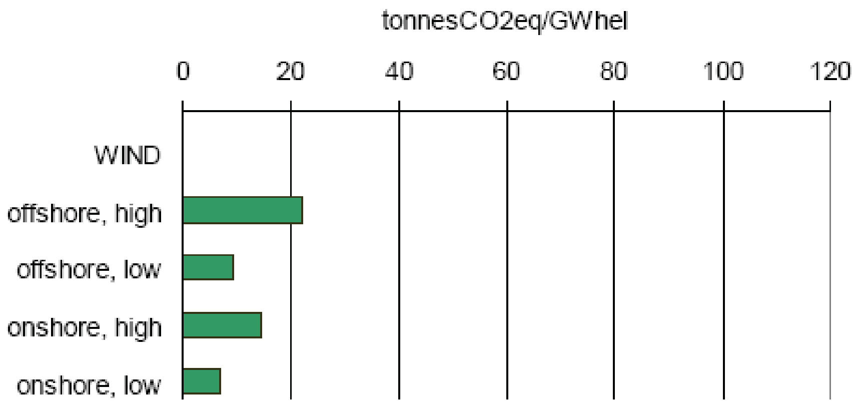
Table 6.6: Summary of carbon emissions (gCO_2/kWh) from the literature

Source	2010	2020	2030
Onshore	8 - 30 (IAEA, 2006) 4.64 (POST, 2006) 8 - 15 (WEC, 2007)	13	11
Offshore	9 - 19 (IAEA, 2006) 5.25 (POST, 2006) 10 - 22 (WEC, 2007)	12	10

Source: SQW Energy and sources shown in the table

The results indicate that the carbon footprint of onshore and offshore wind is small, despite considerable differences between the amount of carbon produced during the construction and manufacturing phase. Offshore wind turbines require significantly higher amounts of steel and cement than an onshore counterpart for construction and thus have a higher carbon impact. However, this discrepancy is evened out as the amount of GHG emissions produced per kWh is dependant on the total output. The offshore turbines will produce more electricity due to their larger size and because they are in locations that are more windy. Since damages are measured against the electricity produced, it is clear that good wind sites will have lower carbon emissions per kWh. (WEC, 2004), see Figure 6.15.

Figure 6.15: Life cycle carbon emissions from wind in tonnes of CO_2 per GWh



Source: World Energy Council

6.4.3 Supply and infrastructure vulnerability

The literature does not allude to any specific possible infrastructure damage caused by changing climate conditions on wind farms. Damage could be caused from intense storms due to wind speeds increasing to levels that wind turbines are not able to handle. In these cases the turbines would be shut down in order to prevent damage to the machines. The damage to infrastructure is thus minimal.

6.4.4 Availability change of the resource

With the growing importance of wind power, there have been an increasing number of studies looking at changes in wind speed and the impact on energy production. A key outcome is that while there are clearly significant increases in energy capture with raised wind speeds, these are capped by the need for current generations of turbines to furl in high winds.

The Community Climate Change Consortium for Ireland (C4I)[38] project for Ireland is mapping the changing wind resource as a result of climate change. Results for the simulations show an overall increase in mean wind speeds for the future winter months and a decrease during the summer months. The most extreme increases in the mean cube wind speed arise during February with increases of about 12 per cent in the north of the country The overall mean cube wind speed increases by approximately 1.0 per cent over most of the country.[39] This is confirmed by the IPCC which reports that average wind speeds are projected to increase in Western Europe [40]. The increase in the wind resource as a whole will mean that there is an increase in the amount of wind available for wind energy generation in Ireland.

38 Community Climate Change Consortium for Ireland, (www.c4i.ie)

39 Lynch, P., McGrath, R., Nolan, P., Semmler, T and Wang, S.,2006, *Ireland's Changing Wind Resource: An Atlas of Future Irish Wind Climatology*, Geophysical Research Abstracts, Vol. 8.

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40 Intergovernmental Panel on Climate Change, 2007

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The Irish Energy Tetralemma

Fuel Report 7: Solar Energy

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ There is no fuel input cost associated with solar energy. ▪ Solar energy is not extensively used in Ireland and there is scope for harnessing a higher proportion of this resource.
Delivered energy cost	▪ Solar Photovoltaic (PV) is currently an expensive way of producing electricity, though costs are falling. ▪ Solar heating is one of the cheaper forms of renewable energy to exploit.
Policy & Regulation	▪ There are relatively few barriers to exploiting solar energy in Ireland, which benefits from the recent introduction of an exemption from planning permission for microgeneration. The lack of an export market to the national grid for micro-generated electricity presents a financial barrier to solar PV (though a generous export tariff would be required to offset the high capital costs associated with the technology). ▪ A wide range of installation grant schemes for households and businesses are available for renewable electricity production, including solar PV and solar heating. An additional incentive includes the introduction by several County Councils of mandatory renewable energy and low-carbon requirements for new developments.
Market context in Ireland	▪ Solar thermal has an established (albeit small) market and a mature supply chain in Ireland and internationally. ▪ Solar PV on the other hand lacks an established market and economies of scale in Ireland where the solar resource is not particularly attractive (compared to other more southern countries) and the cost of schemes is very high.

Security of supply

Import dependence	▪ Solar energy is indigenous and not import dependent. ▪ It represents a negligible contribution to the national energy mix.
Fuel place of origin	▪ Solar energy is indigenous and highly secure.
Supply and Infrastructure resilience	▪ Solar energy in Ireland for the foreseeable future is likely to consist of relatively simple, small-scale installations sized to meet local demand. The simplicity and independence of these systems means that the infrastructure security of this fuel source is very high. Solar PV has a marginal lead over solar thermal due to a simpler

	and more robust system design.
Market volatility	▪ There is no fuel market for solar energy as such. Furthermore, solar thermal is particularly attractive as the supply chain is well established and diverse and many goods and services are provided locally; whilst solar PV is more prone to international supply bottlenecks. ▪ Internationally, markets for solar energy equipment are well developed but patchy, tending to follow the pattern of solar energy incentives. The security of the equipment supply chain is likely to improve as the Irish market matures. Solar PV is currently affected by a global shortage of silicon wafers, though this issue could be alleviated by new capacity in the short term.
Energy availability and intermittency	▪ Solar energy is inherently intermittent. This applies to both solar thermal and solar PV. ▪ The amount of available solar resource is a function of latitude, weather and the time of day, though the simplicity of solar systems means downtime for maintenance should be small. Availability of around 8-15 per cent of maximum capacity is typically observed.

Sustainability

Fuel longevity	▪ There is an infinite amount of solar energy available.
Environmental impact	▪ Both types of solar energy have a very low environmental impact, along with most other renewables. ▪ The external costs of using solar technologies are based on the assumption that PV technologies are produced using fossil fuel power. The external costs for using PV are therefore equivalent to the average external costs for the rest of the power sector in Ireland.

Climate change

Carbon content	▪ Solar energy does not have any carbon (or any other chemical).
Lifecycle carbon footprint	▪ Solar achieves the highest score against this indicator. ▪ Most of the GHG emissions occur upstream of the life-cycle with the majority of the emissions arising during the production of the module – anywhere between 50 per cent and 80 per cent. Other significant GHG releases in the upstream relate to the balance-of-plant (BoP) and the inverter. Operation, end-of-life and associated transport activities do not result in meaningful cumulative GHG emissions. Total lifecycle emissions are expected to be between 35 gCO_2/KWh and 73 gCO_2/KWh.

Supply and infrastructure vulnerability	▪ There are unlikely to be effects on solar thermal or solar PV infrastructure as a result of climate change.
Availability change	▪ Climate change is expected to result in higher temperatures which will mean marginally more solar thermal resource. The resource for solar electric power (solar PV) will remain broadly unchanged.

7.1: Solar power: the basics

Solar energy covers two different technologies for harnessing the power of the sun: solar thermal and solar photovoltaic (PV) cells.

Solar thermal energy is harnessed through solar collectors. Collectors can be evacuated tubes, flat plates or a system of mirrors or lenses. Flat plates and evacuated tubes are generally used in commercial thermal systems for water heating. Mirrors and lenses are generally used for electric power production at solar thermal power plants where the mirrors/lenses concentrate sunlight into small areas. The resultant heat is used to create steam to drive turbines and generators, much like conventional power stations.

The dominant solar thermal technology in Ireland in the foreseeable future is likely to be solar heating, rather than solar thermal power production. For this reason, solar heating is the technology considered in more detail below.

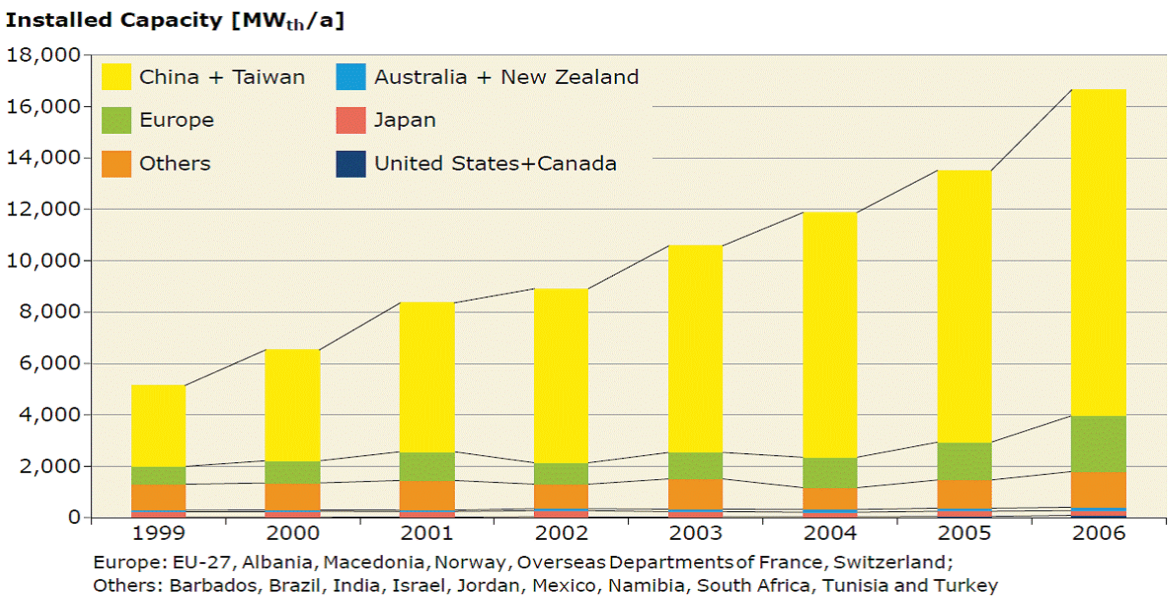
Solar PV cells convert energy from the sun directly into electricity. PV cells are usually made from solid-state semiconductors using materials such as silicon (mono- or poly-crystalline or amorphous film), copper indium diselenide (CIS) and cadmium telluride. PV cells are designed with a positive and negative layer, creating an electric field, similar to a battery. As photons (energy from the sun) are absorbed by cells they cause electrons in the cells to become free, move across the cell and exit through a connecting wire. This flow of electrons can be harnessed as useful electricity.

Current and future trends

Global context

Figure 7.1 below shows the growth in annual installed global solar heating capacity from 1999 to 2006. By far the largest market is China, though growth is strong across the world, including Europe.

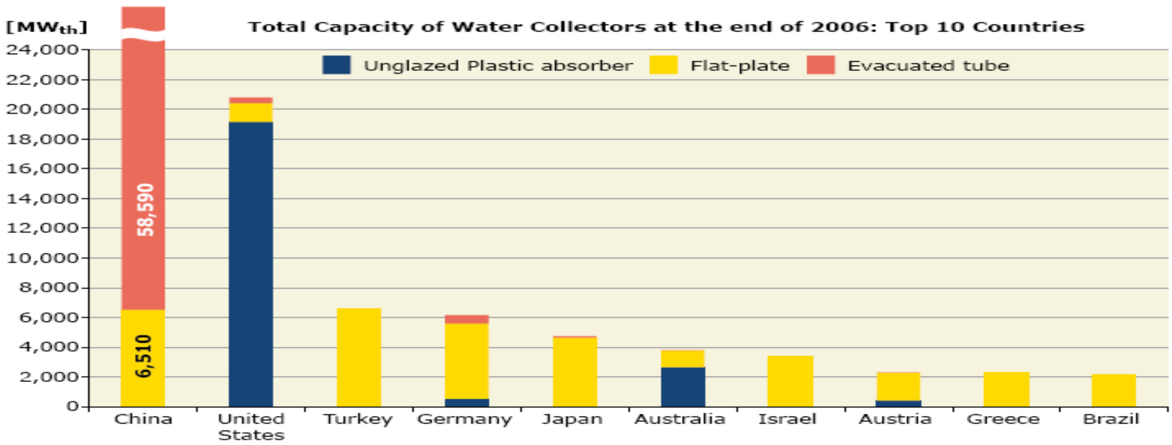
Figure 7.1: Installed solar thermal capacity per annum, 1999-2006



Source: IEA, 2008

The design of solar thermal systems varies significantly from country to country, as illustrated by the chart below (Figure 7.2). While the most popular technology world-wide is the evacuated tube design predominant in China, the most common technology in European countries is the flat-plate collector, used for space and hot water heating[1].

Figure 7.2: Total capacity in operation of water collectors of the 10 leading countries at the end of 2006

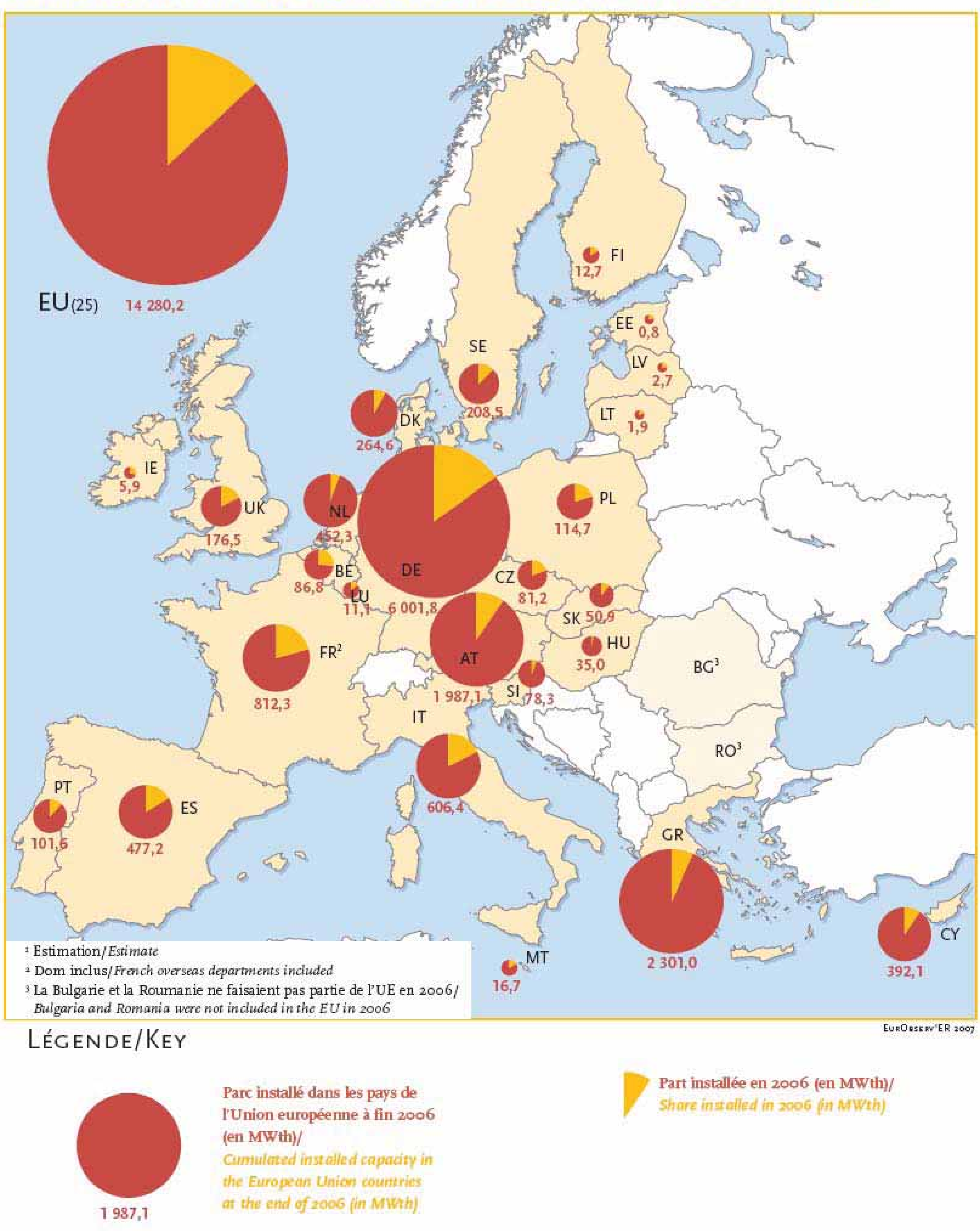


Source: IEA, 2008

1 The unglazed plastic absorber technology common in the United States and Australia is used mostly for heating outdoor swimming pools

Figure 7.3 below shows installed solar thermal capacity across Europe (the lighter slices in the pie charts show capacity installed in 2006).

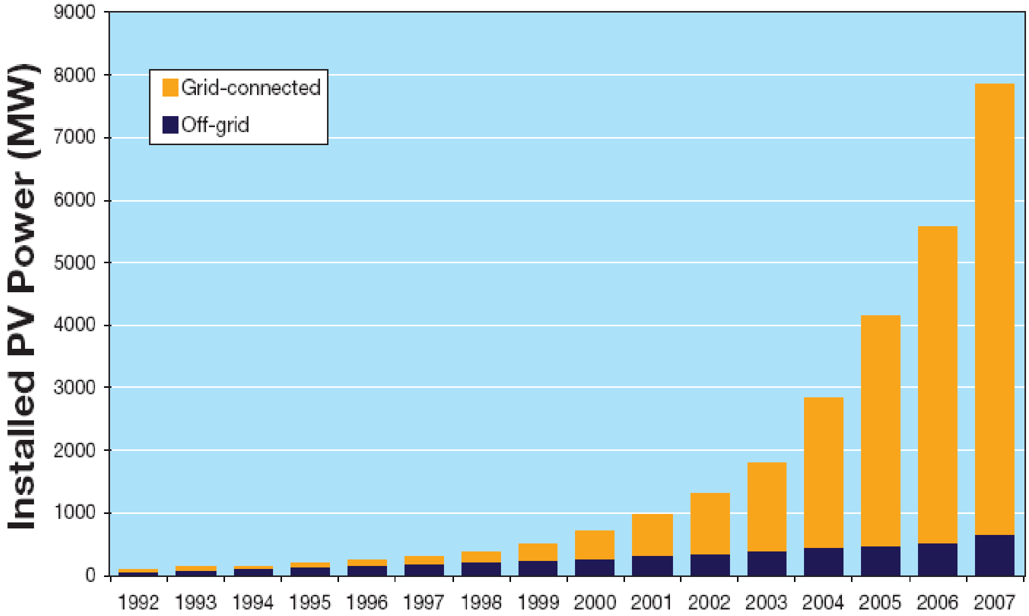
Figure 7.3: Installed solar thermal capacity in EU-25 countries.



Source: EurObserv'ER, 2007.

Figure 7.4 below shows the growth of solar PV installations in selected IEA countries from 1992 to 2007[2], with significant growth from 2002 onwards.

Figure 7.4: Cumulative installed grid-connected and off-grid PV power in selected IEA member states

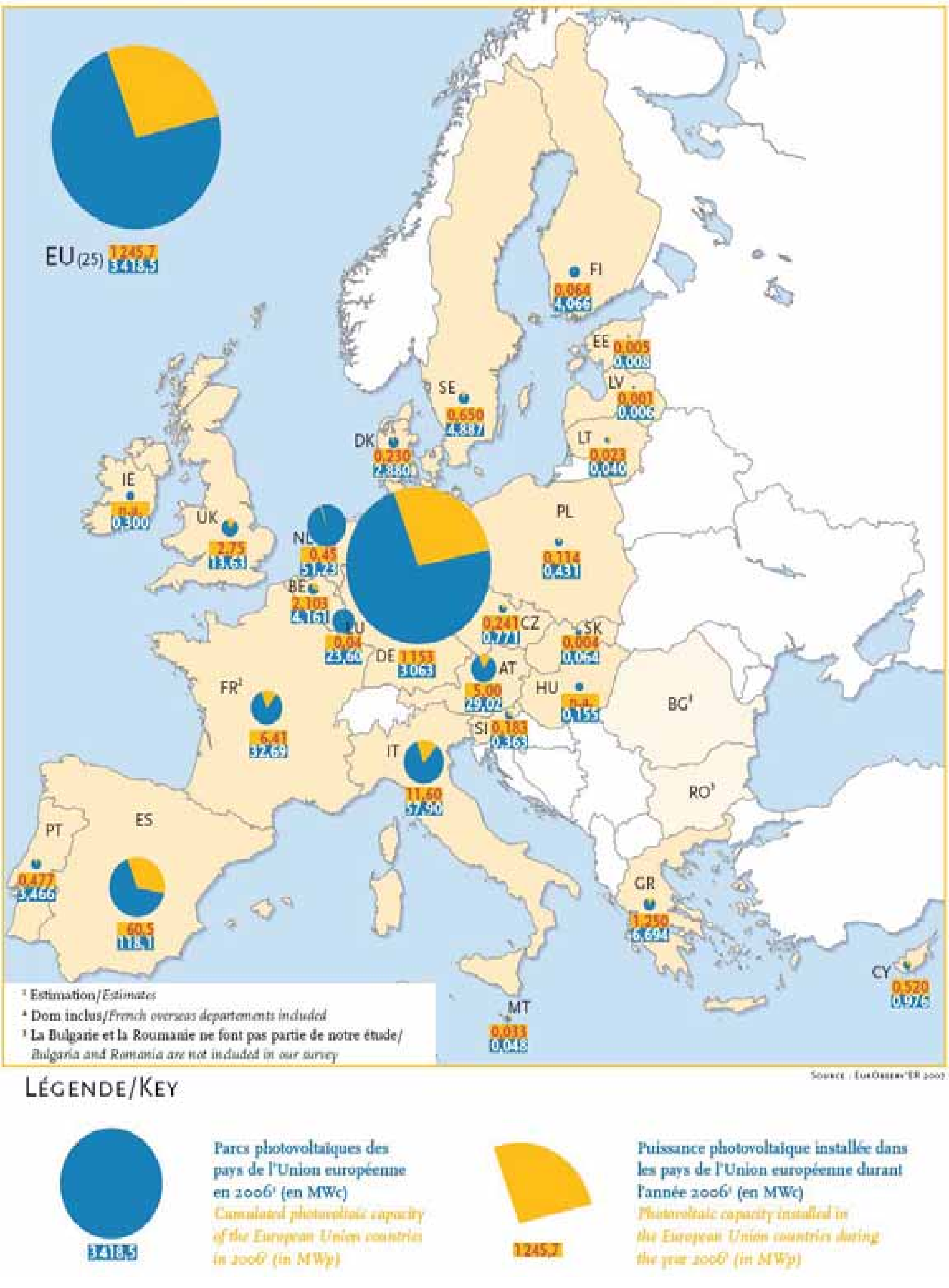


Source: IEA, 2008a

Figure 7.5 overleaf shows the breakdown of installed European solar PV capacity in 2006 (the lighter slices in the pie charts shows capacity installed in 2006).

2 Participating countries are Australia, Austria, Canada, Denmark, France, Germany, Israel, Italy, Japan, Korea, Mexico, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, the United Kingdom and the United States of America. These countries are likely to include the bulk of global installed capacity. Figures do not include China, which was estimated to have approximately 100 MW of installed PV capacity in 2007 (ibid)

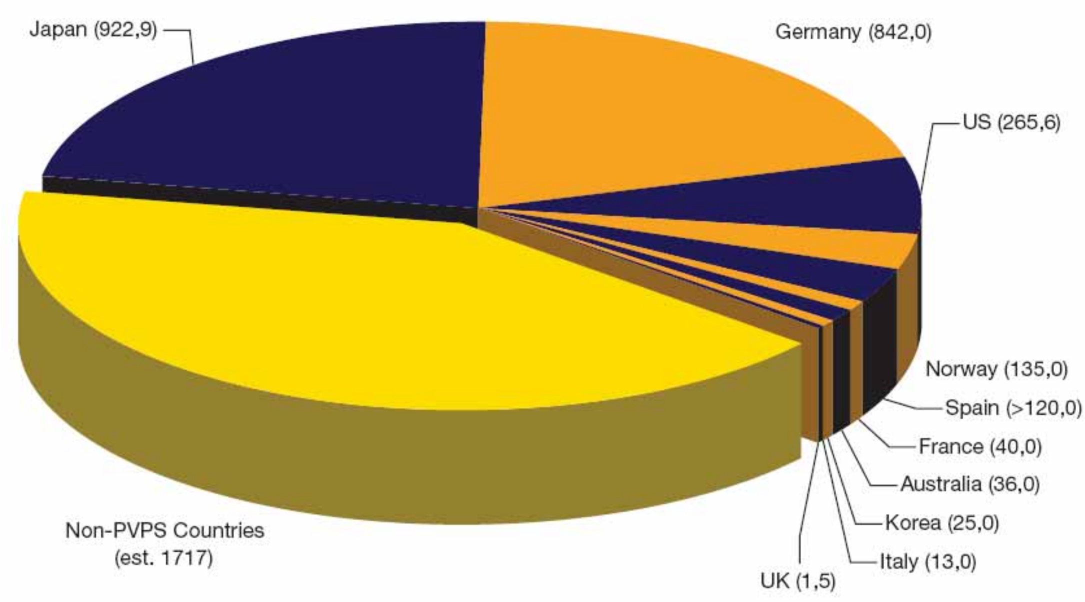
Figure 7.5: Installed solar PV capacity in Europe, 2006



Source: EurObserv'ER (2007a)

Part of the explanation for the rapid growth of solar PV lies in the Figure 7.5 above; clearly Germany is not the sunniest country in the world, and yet it accounts for almost half of global installed solar PV capacity. The reason is that Germany has implemented a very generous subsidy regime for small-scale renewables, and solar PV in particular. One of the principle aims was to encourage the development of the solar PV supply industry, and the policy has been a success. Figure 7.6 below shows that Germany has captured a significant share of the global market for PV modules.

Figure 7.6: Global PV cell production (MW) by country in 2007

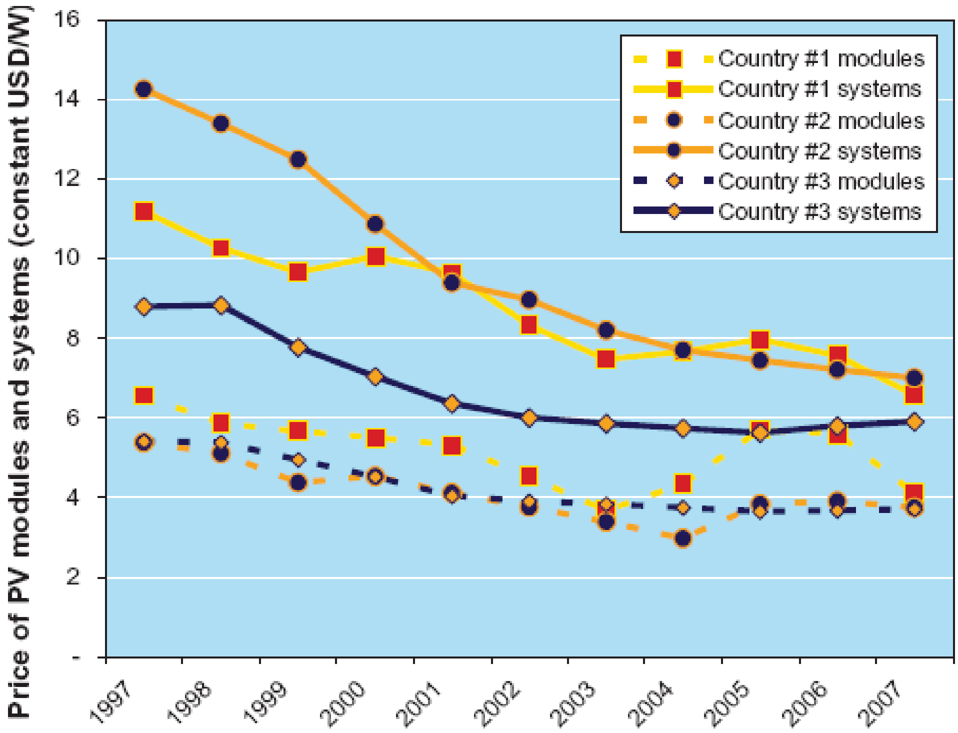


Source: IEA, 2008a. "Non-PVPS" is an estimate of the market share of all counties not covered by the IEA survey, including China (~1000 MW of cell production in 2007) in and India (~100 MW).

Figure 7.7 below illustrates how technology development and economies of scale from the rapidly expanding market have pushed installation prices significantly lower over the past decade. This rapid growth has led to bottlenecks in the silicon wafer supply chain and put upward pressure on prices, but this trend is expected to reverse as silicon supply expands to meet demand[3].

3 EE Times, 2008, *Silicon supply shifts solar dynamics*, Press release-10 June 2008

Figure 7.7: Evolution of price of PV modules and systems in selected IEA countries, accounting for inflation 1997-2007

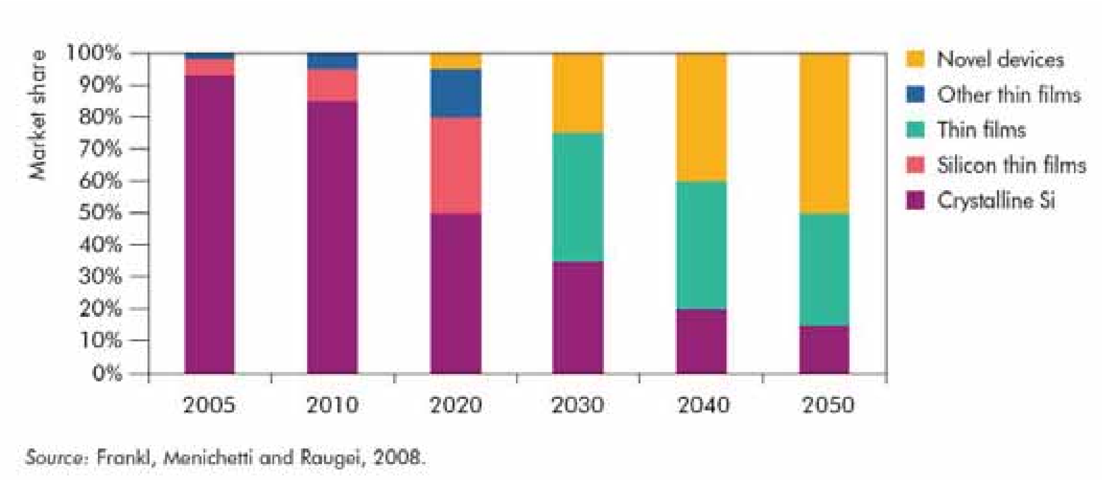


Source: IEA, 2008a

IEA forecasts suggest that the solar PV market will look very different in 2050, with the development of thin film and other as yet unforeseen technologies (see Figure 7.8). The cost of solar PV systems could fall by a factor of two or more, depending on technological advances and the level of deployment[4].

4 IEA, 2008b, *IEA Energy Technology Perspectives 2008*

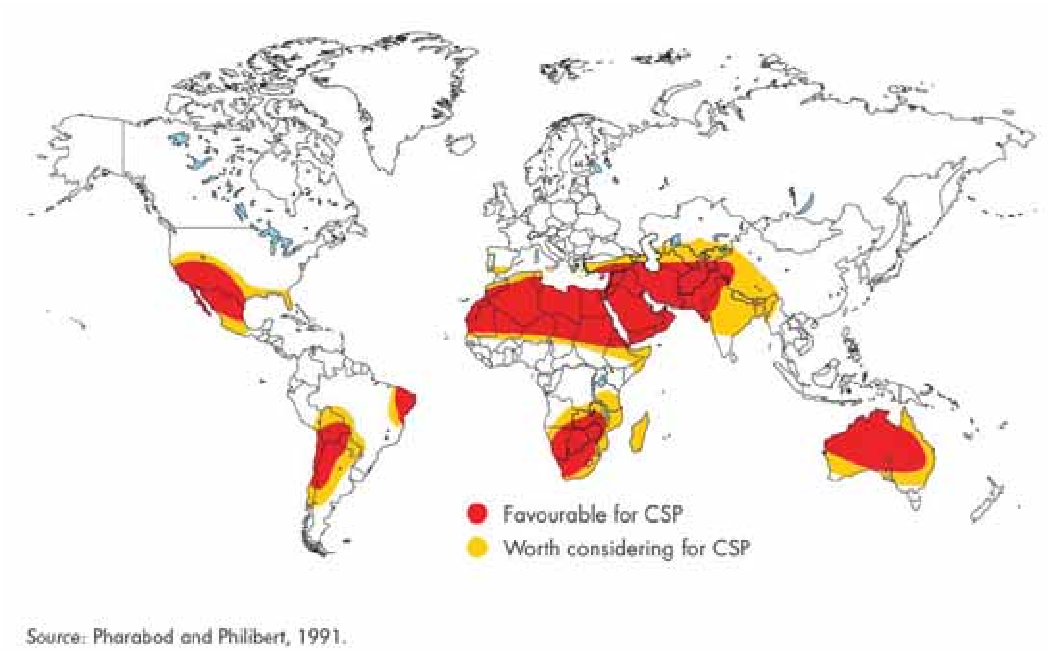
Figure 7.8: IEA forecast of solar PV market evolution to 2050



Source: IEA, 2008b

The IEA forecast that solar thermal power will play an increasing role in energy supply, although Ireland lies far outside the areas deemed suitable for concentrated solar power plants, with most of the promising areas in the Southern hemisphere, see Figure 7.9.

Figure 7.9: The most promising areas for concentrated solar power plants



Source: IEA, 2008b

Irish context

The solar energy market in Ireland is at a very early stage of development. The latest provisional figures for 2007[5] show that solar energy accounts for about 1 ktoe from total final energy consumption of 13,336 ktoe, or less than 0.01 per cent. The European Commission[6] forecasts that the solar energy in Ireland will grow to account for 67 ktoe out of a final energy demand of 15,714 ktoe, which is still under 0.5 per cent of total final energy demand. Solar PV is forecast to increase from under 10 MW today to about 100 MW by 2030 – less than 1 per cent of total forecast generating capacity.

However, the European Commission forecast is based on existing policy measures at the time of publication, and may not take account of recent developments, such as the introduction by several County Councils of mandatory renewable energy and low-carbon requirements for new developments[7], and the exemption from planning permission recently granted for microgeneration in Ireland.

The 2007 Energy White Paper (DCENR, 2007) identified the long-term potential for solar energy, stating:

Solar energy has long term potential for Northern European countries, including Ireland. Our strong high-tech manufacturing capability points to the potential for us to play a greater role in the development and manufacturing of this technology.

… We will pursue the potential for solar energy in Ireland in photovoltaic and solar thermal research, technology and manufacture with a view to optimising deployment of solar energy in electricity and heating by 2020;

However, while solar energy in Ireland is supported by renewable energy policy initiatives and grants, and there are targets for renewable heat and electricity[8], there are no specific targets or forecasts associated with solar energy. There is no firm evidence to support a quantitative estimate of the contribution that solar energy will make to meeting Ireland's energy demand in the foreseeable future[9].

Figure 7.10 below shows the level of solar insolation[10] across Europe (in average kWh/m^2/day), and shows that Ireland has a relatively low level of solar resource concentration.

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5 SEI, 2008, *Sustainable Energy Ireland, Irelands provisional energy balance,* 2007

6 EU-27 Energy baseline scenario to 2030, 2007 update. Consistent with this finding, the Green-X model predicts available solar PV resource in the region of 26 ktoe/year by 2020 (Green-X, 2004)

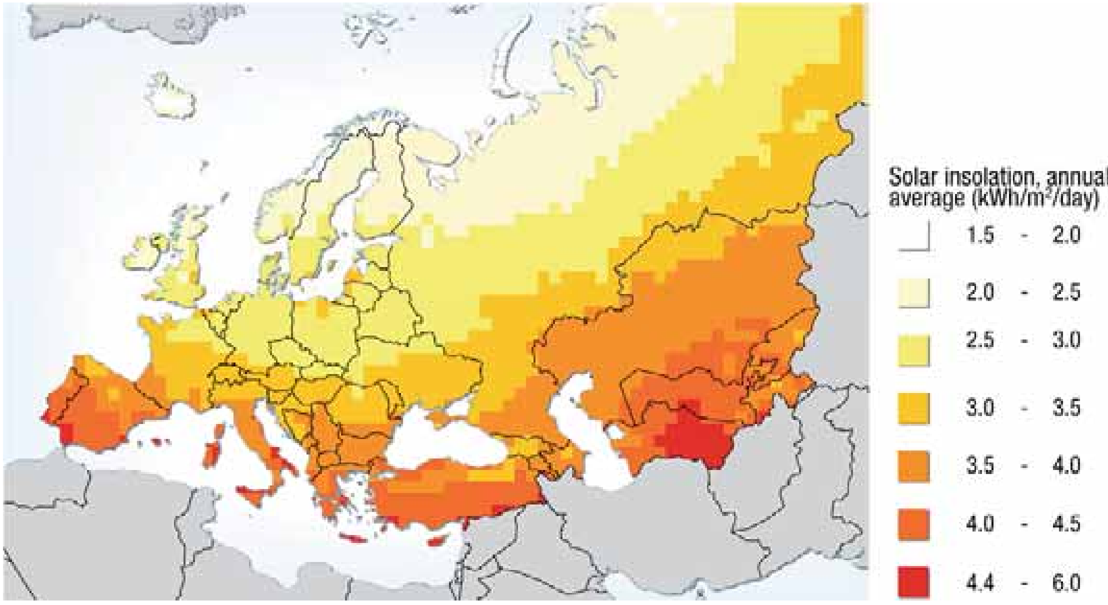
7 For example (Genersys, 2008): "at least 30per cent of space and water heating shall be from a renewable energy source"

8 12 per cent and 13 per cent of heat and electricity to come from renewable sources by 2020, respectively

9 For example, (SEI, 2008b) – in the forecast to 2020, no specific estimate is made of the potential contribution from solar energy

10 Solar insolation is the quantification of energy per surface area on the ground, and can be used as an indicator for the potential for solar energy

Figure 7.10: Solar insolation across Europe (average kWh/m²/day)



Source: EEA, 2007

Although the concentration of solar energy in Ireland is low, there is still a considerable total amount of resource available. A 2004 study into Ireland's renewable energy resource[11] constructed resource cost curves for solar energy in 2020, as shown in Table 7.1 below. Accessible resource was estimated by approximating the total roof area available for solar thermal installation.

Table 7.1: Estimated Irish solar thermal resource curve for 2020

Resource Curve 2020	Quantity, GWh (ktoe)	Cost, cents/kWh (€/GJ)
Large Scale Installations	-	5.68 (15.8)
Large Scale Installations	17,143 (1,474)	5.68 (15.8)
Small Installations	17,143 (1,474)	7.09 (19.7)
Small Installations	33,712 (2,899)	7.09 (19.7)

Source: SEI, 2004

The accessible resource is significant, amounting to over 75 per cent of total predicted Irish thermal energy demand in 2020[12] . However, the relatively high cost compared to conventional alternatives (estimated as 1.41 c/kWh or 3.9 €/GJ in the same study) presents a significant commercial barrier to the exploitation of this resource.

11 SEI, 2004, *Renewable Energy Resources in Ireland for 2010 and 2020*, 2004

12 SEI, 2004, This is estimated to rise to 92 TWh / 7,900 ktoe by 2020

High, medium and low estimates for solar thermal exploitation in 2010 and 2020 from the same study are shown in the Table 7.2 below. The maximum likely solar output in 2020 is 0.1 per cent of total predicted thermal energy demand in 2020.

Table 7.2: Estimated annual Irish solar thermal output under different market penetration scenarios

Solar thermal output, MWh (ktoe)	2010	2020
Low	4.8 (0.4)	24.0 (2.1)
Medium	11.5 (0.99)	54.8 (4.7)
High	22.7 (2.0)	109.2 (9.4)

Source: SEI, 2004

7.2: Solar as an energy source

Solar is a renewable energy resource which will be available indefinitely into the foreseeable future. Solar irradiation continuously reaches the Earth and its amount only fluctuates as a result of solar activity and the ability of the atmosphere to retain a portion of it (currently the trend is of higher retention capacity – global warming).

Solar energy is free, is an indigenous resource and as such it is highly secure.

Table 7.3: Competitiveness: fuel cost for solar energy

Fuel cost, €/GJ	2010	2020	2030
Solar thermal	0	0	0
Solar PV	0	0	0

Source: SQW Energy

7.3: Solar energy in the energy system

7.3.1 Delivered energy cost

Solar PV

Delivered cost estimates for solar PV cover a very wide range. This is partly because the solar yield in different locations varies significantly, but also because it reflects wide variations and uncertainties in component and manpower costs.

Future delivered costs will depend both on the evolution of equipment and installation costs and on the level of market penetration. Technology costs should fall as the market matures, putting downward pressure on costs. However, the cheapest, most readily available resource should be exploited first, with the more difficult (and expensive) resource exploited subsequently – this puts an upward pressure on long-term costs. Estimates of costs extending to 2030 are hard to find, but on balance costs are generally expected to fall as the technologies and markets mature.

Table 7.4: Competitiveness: estimates of delivered cost for solar PV

Solar PV: Delivered cost, €/GJ	2010	2020	2030
IEA, 2005	27-338	-	-
DTI, 2007	169-249	132-194	-
SEI, 2004	190	-	-

Source: SQW Energy

Solar thermal

Delivered energy costs for solar heating are significantly lower than those for solar PV. This is because the collection systems are cheaper, and the sun's energy is converted directly into useful heat rather than incurring the losses via conversion to electricity[13].

Estimates of solar thermal costs face similar problems to solar PV, in that they are correlated to the available resource, so costs for the same installation in different counties can be quite different. Delivered energy cost estimates for solar thermal have been difficult to source – particularly estimates of how costs will evolve to 2030.

13 However, a GJ of heat energy is worth less than a GJ of electricity, and there are fewer useful things you can do with it

Table 7.5: Competitiveness: estimates of delivered cost for solar thermal

Solar thermal: Delivered cost, €/GJ	2010	2020	2030
SEI (2004)	17-23	16-20	-
Pöyry (2008)	6-17	-	-

Source: as shown in the table

7.3.2 Policy and regulation

In Ireland, as in most countries, the planning process is the main regulatory barrier faced by solar energy. Even when no specific barriers are in place, local planning departments tend to take a precautionary approach when faced with new technologies. However, solar PV and heating will both benefit from the introduction of an exemption from planning permission for microgeneration in Ireland[14].

Grid connection presents an additional regulatory barrier for solar PV systems. In Ireland, different rules apply depending on the size of the installation:

- Microgeneration systems (below 11 kW) face a relatively straightforward connection process, although customers have to notify the grid operator, install a system with the network's technical standards and use a registered electrical contractor[15].
- Systems above 500 kW are subject to the regulator's Group Processing Scheme[16]. Whilst applications to connect under this scheme have generally been successful, the process is more onerous and time-consuming than that faced by microgenerators.
- Systems between 11 kW and 500 kW follow the standard connection process, and are assessed on a case-by-case basis[17]. Generators usually receive a connection offer within 4-6 months[18].

The lack of clear guidance for generators in the 11 kW to 500 kW is being addressed through ongoing work commissioned by SEI which should result in a lightening of the regulatory load through time. However, the barriers to electricity generation are likely to remain higher than for thermal generation in the foreseeable future.

Incentives for solar heating include the Renewable Heat (ReHeat) Deployment Programme[19], which provides grants for the deployment of renewable heating systems in industrial,

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14 RES, 2007, *Planning Exemptions for micro renewable technology welcomed by energy group*, Press release 2 March 2007

15 ESB,2008, *ESB guidance for connecting a micro-generator*, 2008

16 CER, 2008, *CER guidance on the group connection process*

17 ESB,2008a, *ESB guidance on connecting a renewable/embedded generator*, 2008

18 Econnect, 2008, *Comprehensive guidance on connecting to the electricity grid in Ireland* (forthcoming), 2008

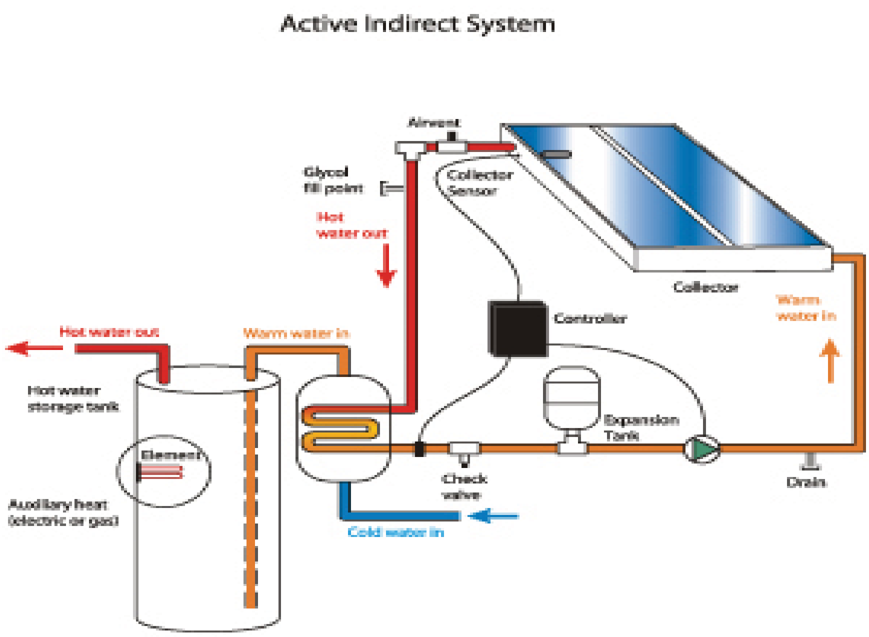
commercial, public and community premises in Ireland. A wide range of installation grant schemes for households and businesses are available for renewable electricity production, including solar PV. An additional incentive includes the introduction by several County Councils of mandatory renewable energy and low-carbon requirements for new developments[20].

7.3.3 Supply chain and infrastructure resilience

Solar thermal is normally used to meet a proportion of on-site heat demand. The equipment involved with this is very simple:

- A solar collection device: in European markets the flat plate collector design is most common. This is a flat, darkened plate, usually roof-mounted, containing a winding copper pipe filled with working fluid[21].
- The hot working fluid from the collector is channelled via pipes to a standard hot water tank, where it deposits the heat gathered.
- In **passive** systems the working fluid is driven through the system by a combination of gravity and thermodynamics – i.e. it circulates without the aid of pumps or controls. **Active** systems use pumps to circulate the working fluid, see Figure 7.11.

Figure 7.11: A typical solar thermal system (active)



Source: Southface (2008)

19 SEI,2008a, SEI Grants information is available on the SEI website, 2008

20 Genersys, 2008, *Dun Laoghaire-Rathdown to introduce sustainable planning requirements*, news item, 2008

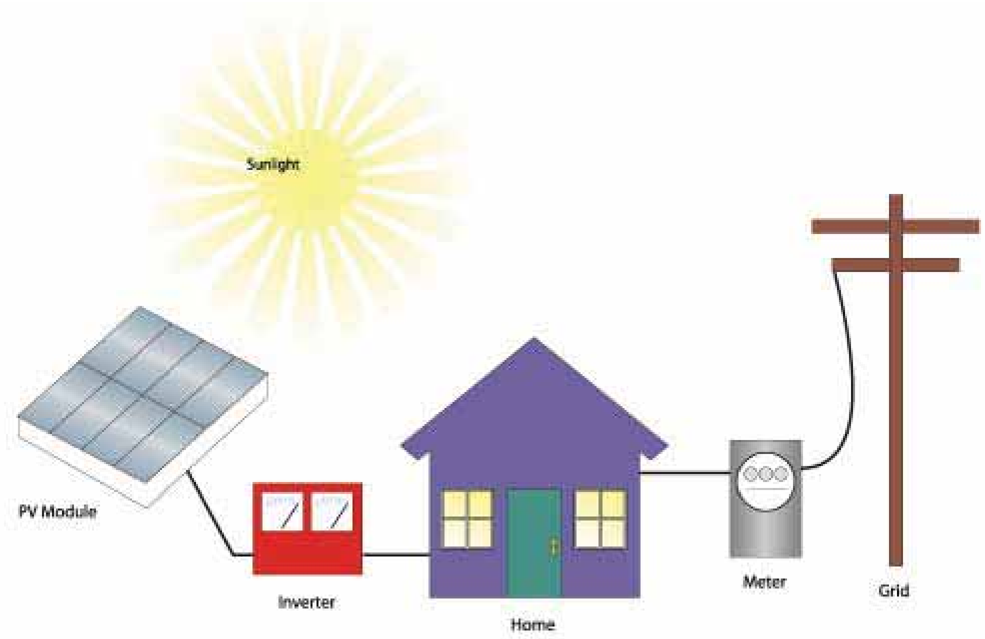
21 In warm countries the working fluid can be water; in countries such as Ireland where the temperature drops below freezing the water will include anti-freeze

The simple, compact and robust nature of the system makes it a very reliable energy infrastructure. On the assumption that future systems will be at least as simple and robust as current systems, this level of security will be maintained to 2030.

Solar PV is normally used to meet a proportion of on-site electricity demand. The equipment involved with this is also very simple:

1. A solar collection device: this usually consists of a roof-mounted, flat, semiconductor module.
2. DC output from the module is converted into AC by an inverter.
3. The inverter is connected directly to the electricity system and helps to meet on-site electricity demand. Some countries allow excess power to be sold back to the grid.
4. On large-scale systems tracking devices can be used to maximise the utilisation of incident solar energy.

Figure 7.12: A standard solar PV system.



Source: Southface, 2008

Again the simple, compact nature of the system makes this a very reliable energy infrastructure. On the assumption that future systems will be as simple and robust as current systems, this level of security will be maintained to 2030.

7.3.4 Market context in Ireland

Solar energy is estimated to form a tiny part of Ireland's energy mix, accounting for less 0.01 per cent of total primary energy supply[22]. The policy environment in Ireland is favourable towards solar and other forms of decentralised and renewable energy so this figure is likely to rise.

Experience in other countries (notably Germany) shows that the barriers to developing this sector are not insurmountable. However, overcoming these obstacles – principally the cost barrier – is likely to require a significant amount of targeted investment, supported by clear objectives for the growth of the sector. In the absence of this level of support becoming available in Ireland, it is likely that solar energy's contribution to the Irish energy mix will remain small.

7.3.5 Energy availability and intermittency

Solar thermal and solar PV equipment is highly reliable, requiring very little maintenance. Maintenance that is required (cleaning panels and checking the plumbing in the working fluid for solar thermal devices) can often be carried out after sunset.

For this reason, the availability of these devices is very much determined by resource availability. The actual power output at a particular point in time will be less than the rated value by a factor, depending on geographical location, time of day, weather conditions, shading, and other variables.

The average capacity factor for a typical Irish solar PV is currently 8 per cent; lower than the 11 per cent figure achievable in Mediterranean Europe, but comparable with 8 per cent in Germany [23]. Typical international capacity factors for advanced, large scale solar PV lie between 15 and 25 per cent[24]; however the conditions in Ireland are unlikely to encourage solar power production on this scale, or at this level of efficiency. This study assumes that the average capacity factor for Ireland will improve slightly over the next two decades as the technology develops.

The average capacity factor for a solar thermal power installation in Ireland is currently 10 per cent (BERR, 2008). This compares with average values of 13 per cent in Germany and 21 per cent in Portugal and Spain. We assume that the average capacity factor increases gradually over time as the Irish market matures and the technology develops.

7.3.6 Market volatility

There is no fuel market for solar energy. Internationally, markets for solar energy equipment are well developed but patchy, tending to follow the pattern of solar energy incentives –

22 SEI, 2008, *Ireland's provisional energy balance*, Sustainable Energy Ireland, 2007

23 Pöyry, 2008, *Compliance Costs for Meeting the 20 per cent Renewable Energy Target in 2020*, report to BERR

24 PV Resources, 2007, *List of the world's largest PV power plants*, 2007

countries with mature and generous solar energy incentive schemes have mature solar equipment markets (see the Global Context section above).

There are a wide range of sources for solar thermal and PV technology. The latter is currently affected by a global shortage of silicon wafers, although a combination of new production capacity coming on-stream and the global economic slowdown is likely to address this issue in the short term.

The security of the equipment supply chain is likely to improve as the Irish market matures, though the technological requirements of solar PV leave it more exposed to global market volatility (as illustrated by the current silicon shortage).

7.3.7 Environmental impacts

The external costs of using solar technologies are based on the assumption that PV technologies are produced using fossil fuel power. The external costs for using PV are therefore equivalent to the average external costs for the rest of the power sector in Ireland. External costs are much lower when it is assumed that electrical energy required for the production is not taken from the grid but is produced by the PV technology itself[25]. This is a potential scenario on 2020 and 2030 which will decrease the external costs significantly. SEI have reported that the average external cost for PV and solar thermal technologies are 0.6 euro-cent/kWh and this value is used for all three time periods.

25 ExternE, 1998, *Externalities of Energy, European Commission*

7.4: Solar energy and climate change

7.4.1 Carbon content of fuel

Solar energy does not have any carbon (or other chemical) content. Therefore, the value for the Index is 0.0 $kgCO_2$.

7.4.2 Lifecycle carbon footprint

The IAEA (2006) report that the range for life cycle emissions for solar PV is between 43 gCO_2/kWh and 73 gCO_2/kWh. Most of the GHG emission occurs upstream in the life-cycle with the majority of the emissions arising during the production of the module – anywhere between 50 per cent and 80 per cent. Other significant GHG releases in the upstream relate to the balance-of-plant (BoP) and the inverter. Operation, end-of-life and associated transport activities do not result in meaningful, cumulative GHG emissions.

Future improvements in cumulative GHG emissions from solar PV are likely to arise from improvements in module efficiency, increased lifetime, less silicon mass per module and lower use of electricity for the production process. In this regard it may be important to note that solar PV technology is a relatively fast-improving technology and new LCA studies are frequently being published in order to keep the pace with the advancements (this is also true for other RETs such as wind turbines) (IAEA, 2006).

Dones (2003[26]) reports that lifecycle emissions are to be between 59 gCO_2/kWh and 73 gCO_2/kWh for different solar PV technologies, with emissions decreasing to between 39 gCO_2/kWh and 46 gCO_2/kWh in the future as the technology advances. POST (2006[27]) reports that UK lifecycle emissions are 58 gCO_2/kWh but should be lowered as thin film technologies, using thinner layers of silicon, are produced. However, they do note that the carbon emissions are heavily dependant on the amount of electricity produced (as the emissions are written as a function of this), and therefore CO_2 emissions are considerably lower in southern Europe (35 gCO_2/kWh) as there is more sunlight resulting in a higher energy output.

Table 7.6: Total GHG emissions from Solar technologies

	2010	2020	2030
PV → Electricity	43 – 73 (IAEA) 59 – 73 (Dones) 58 (POST) 35 (POST)	39 – 46 (Dones)	

Source: SQW Energy

26 Dones,2003, *Greenhouse Gas Emissions from Energy Systems: Comparison and Overview*

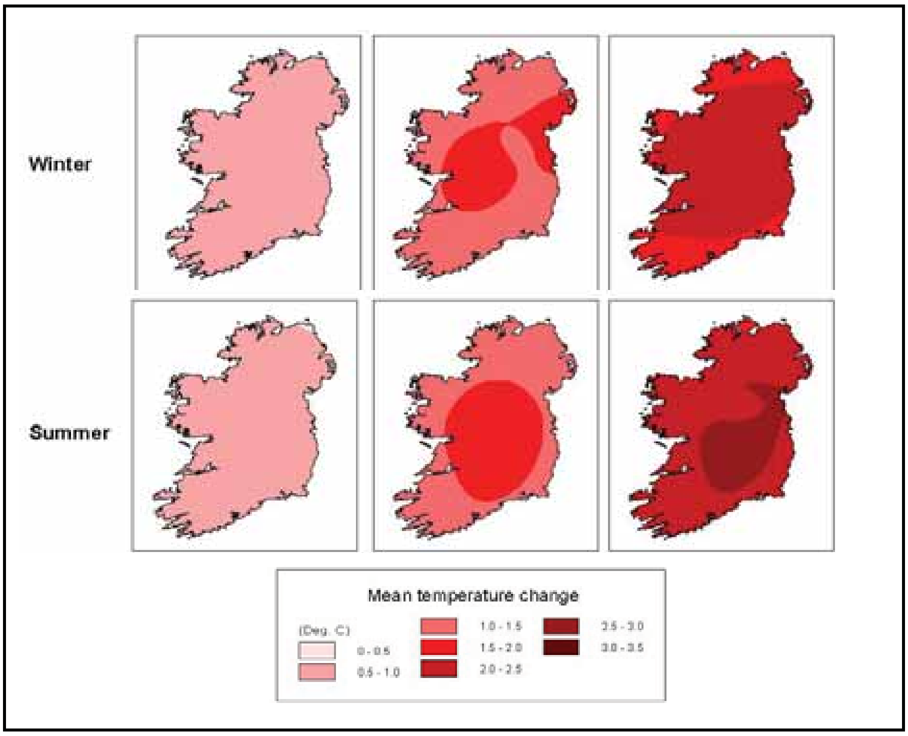
27 Parliamentary Office of Science and Technology (POST), 2006, *Carbon Footprint of Electricity Generation*

7.4.3 Supply and infrastructure vulnerability and availability change of the resource

There are unlikely to be effects on solar thermal or solar PV infrastructure as a result of climate change.

There will be no impact on solar PV resource, however there may be a small increase in the solar thermal resource as IPCC projections for northern Europe show significant warming in the winter (POST 2006[28]). Moreover, the ICARUS project shows that monthly temperatures could increase between 1.25 to 1.5 degrees C by 2055(ICARUS, 2000[29]). The largest will be in the south east and east of Ireland. The changes in temperature are shown in Figure 7.13 below. The extent to which potential solar thermal power plants in Ireland can access and harness this increase in temperature is dependent on the location of the plants. Clearly if they are located near the South East there is more potential for harnessing this extra thermal energy.

Figure 7.13: Projected increase in temperature in Ireland, out to 2055



Source: ICARUS (2000), The Irish Climate Analysis and Research Unit, NUIM (ICARUS)

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28 Parliamentary Office of Science and Technology (POST), 2006, *Carbon Footprint of Electricity Generation*

29 The Irish Climate Analysis and Research Unit ICARUS),2000,NUIM (ICARUS)

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The Irish Energy Tetralemma

Fuel Report 8: Marine Energy

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ There is no fuel cost associated with marine energy resources. ▪ Ireland has a very good marine resource – tidal mainly concentrated along the east coast in the Irish Sea and wave most prominent in the north-west.
Delivered energy cost	▪ Marine technology is in its infancy and therefore not fully commercialised. As such, only small-scale demonstrations are in operation and delivered cost estimates are predominantly modelled (theoretical). ▪ Information on the delivered costs associated with marine energy is based on estimates and projections - these show marine energy to be one of the most expensive and least competitive technologies. This is the case throughout the period to 2030 as a result of relatively low market penetration. ▪ Whilst estimates of delivered cost are wide ranging, costs are expected to fall for both wave and tidal technologies as knowledge of deployment and operational experience improves.
Policy & Regulation	▪ There is a significant level of support for development of the marine energy sector in Ireland with the country's ocean energy strategy originally having been set out in 2005. ▪ As part of Phase 2 of the ocean energy strategy, a funding support package was announced in January 2008 which targeted research and development through to commercial deployment of marine devices. ▪ Because the marine energy sector is at an early stage of development (both globally and in Ireland) regulatory consents and grid connection agreements are likely to be significant barriers to deployment. Barriers should start to be removed as the industry becomes more established.
Market context in Ireland	▪ Marine energy is in its infancy but has significant potential. There is a considerable degree of optimism regarding marine energy. The business climate is generally positive and despite understandable concerns and uncertainties, this technology is hoped to be one that gives a comparative advantage to Ireland. ▪ Marine energy will require infrastructure upgrades. ▪ Ensuring that the grid can accommodate wave and tidal technologies will be key to developing the marine energy sector in Ireland.

Security of supply

Import dependence	▪ Wave and tidal resources are indigenous to Ireland, with no import dependence.
Fuel place of origin	▪ Wave and tidal resources are indigenous to Ireland and highly secure.
Supply and infrastructure resilience	▪ The physical infrastructure for wave and tidal technology is considered to be no more complex than other renewable electricity generating technologies.
Market volatility	▪ The market for marine energy is yet to be fully established as the technological advances required to commercialise the sector at scale have not yet been demonstrated. ▪ Market volatility only refers to the equipment manufacture and associated services and is not burdened by fuel commodity market fluctuations.
Energy availability and intermittency	▪ Marine energy is inherently intermittent. ▪ Wave and tidal devices in development are expected to have capacity factors within the range 30-40 per cent, similar to the capacity factors associated with wind energy.

Sustainability

Fuel longevity	▪ Marine energy, both in its wave and tidal form, is a renewable energy resource which will be available indefinitely.
Environmental impacts	▪ Marine energy is considered to have a very low environmental impact. ▪ Tidal energy devices will change tidal movements and could result in negative impacts on aquatic and shoreline ecosystems, as well as navigation and recreation. ▪ Wave power structures have little effect on the ocean environment, but there is a possibility of local ecology being altered by their presence.

Climate change

Carbon content	▪ The wave and tidal energies use the ocean as a fuel and thus the fuel has no carbon content.
Lifecycle carbon footprint	▪ Marine energy has a very low carbon footprint. ▪ This report presents an analysis of the life cycle energy use and CO_2 emissions associated with the first generation of Pelamis

	converters. With relatively conservative assumptions, the study shows that at 293 kJ/kWh and 22.8 gCO_2/kWh the respective energy and carbon intensities are comparable with large wind turbines and very low relative to fossil-fuelled generation. ▪ Wave and tidal technologies, however, are still in their infancy and the carbon emission calculations for their life cycle have been on prototypes rather than fully commercial systems.
Supply and infrastructure vulnerability	▪ Wave energy is more vulnerable to the climate, whereas tidal energy is more independent of the climate. ▪ Although wave and tidal technologies are under conditions that are hostile, the changes in climate should not affect the infrastructure as the designs of commercial devices would be expected to handle any changes in the ocean environment.
Availability change	▪ Wave energy is closely linked to the climate and will be impacted by any change. Limited evidence is available as to how will the resource change, but is broadly expected to increase. ▪ Tidal energy is independent of the climate (it is created by the pulling force of the moon) and therefore will not be impacted.

8.1: Marine energy: the basics

Marine energy in Ireland primarily covers two ocean energy sources – wave and tidal stream.

Ocean waves are created by interactions between the wind and the surface of the sea, with the size of waves being determined by the wind, bathymetry of the seafloor and currents. They have the potential to provide a sustainable source of energy which can be harnessed and converted into electricity by wave energy converter (WEC) devices. There are many different technologies being developed that harness wave power, with different WECs having been developed to extract energy from shoreline out to the deeper waters offshore.

Tidal stream energy is derived from exploitation of the natural ebb and flow of coastal tidal waters that arise due to the interactions of the gravitational fields of the earth, moon and sun. Sea currents can be magnified by topographical features, such as headlands, inlets and straits, or by the shape of the seabed when water is forced through narrow channels. Most tidal stream devices are broadly similar to wind turbines submerged in the ocean to exploit the kinetic energy in tidal currents.

Tidal energy can also be extracted by building a barrage across a bay, estuary, river or harbour and controlling the flow of water in and out of the area. This is an established method of harnessing energy from tides; however it is extremely location specific. The technology to deploy a tidal barrage in Ireland is not considered in this report.

There are other potential methods for harnessing energy from the sea including osmotic power, ocean thermal energy conversion and marine biomass sources. However, none of these technologies have been proven at scale and are not considered further in this study.

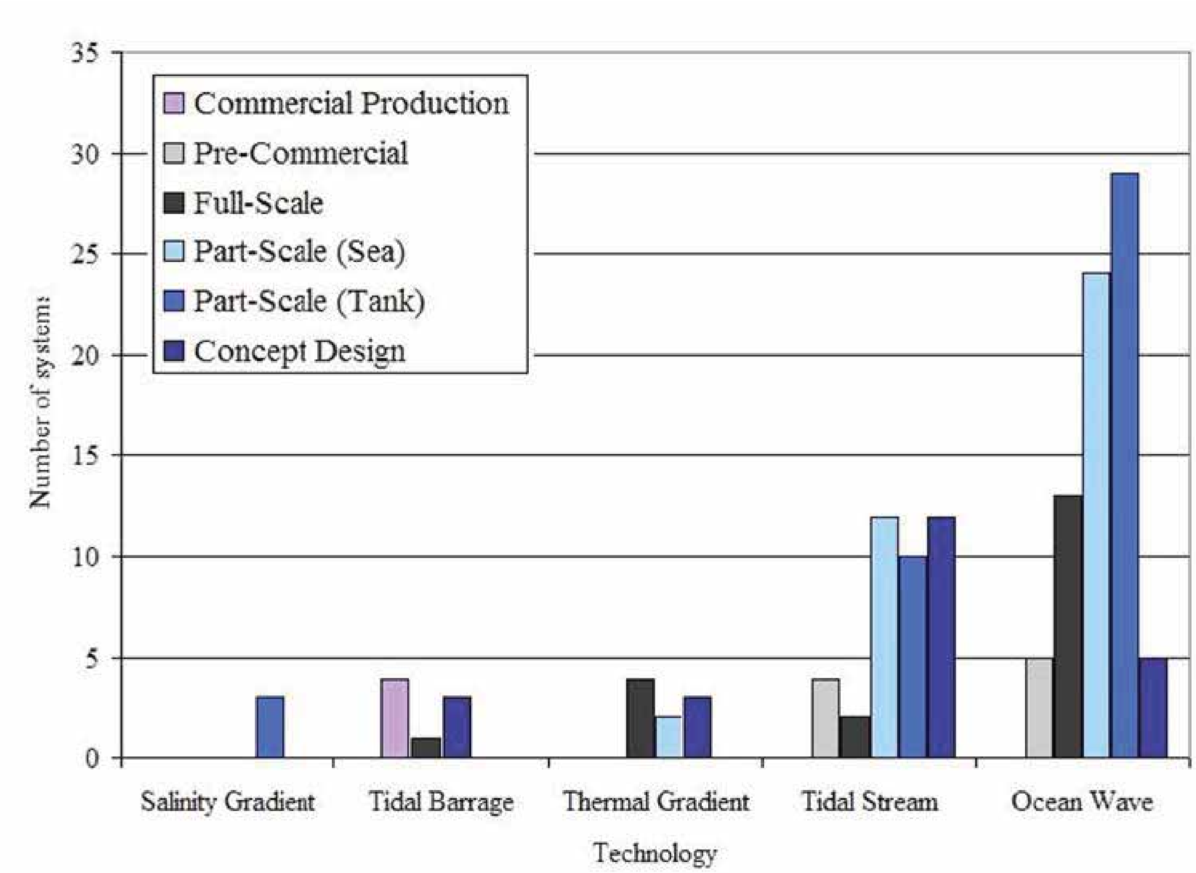
8.1.1 Global context

A variety of technologies that extract energy from waves and tides have been proven at demonstration scale and device developers are now competing for investment and support to deploy at a commercial scale. Some devices are more advanced than others and no optimal design has been agreed upon within the sector.

Several wave and tidal current projects with capacities of up to 500 kW are now operational and generating power to the electrical grid. A number of pre-commercial projects in the range of 1 to 3 MW are either deployed or awaiting deployment in various parts of the world. All devices are at early stages compared to conventional fossil-fuel generators, and renewables such as onshore and offshore wind.

Figure 8.1 provides a snapshot of existing ocean energy conversion technologies and the number of identified projects at various stages of development, with further details for a wide selection of existing projects provided in Figure 8.2. The high number of wave and tidal stream devices in the development chain shows that the sector is not yet close to agreeing on optimal designs for commercialisation.

Figure 8.1: Technology maturity of various ocean energy conversion systems



Source: IEA-OES, 2009

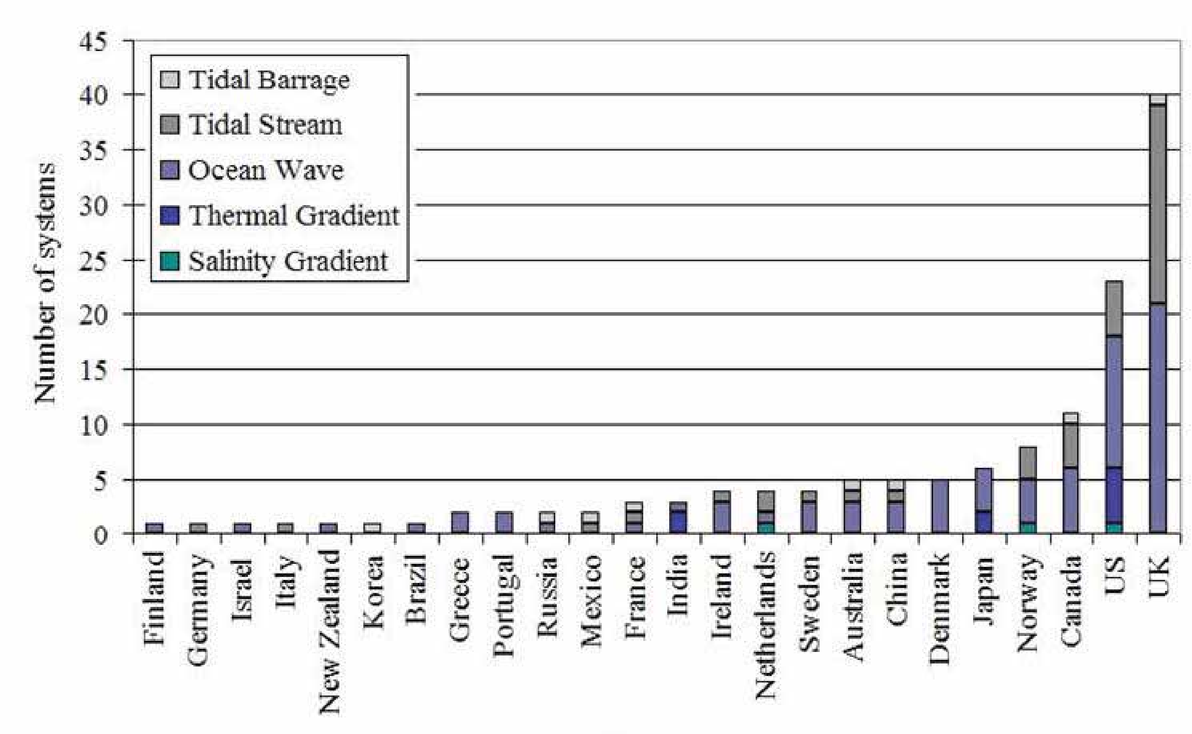
Figure 8.2: Ocean energy technologies – some existing projects in the development chain

Developer/Device	Activites	Stage of development	Demonstration deployment date	Expected/Rated Output (kW)	Year of Deployment
Marine Current Turbines/Seaflow and Seagen				300/1200 (1500 in development)	2003 (300kW) 1.2MW due 2008
Pelamis Wave/WEC				750	2004
Wavegen/LIMPET				500	2000
Open Hydro/Open-Centre Turbine				250	2007
Ocean Power Technology/Power Buoy				40	2004
Lunar Energy/Rotech Tidal Turbine				1000	2008 (expected)
Hammerfest Strom/Tidal Turbine				300	2009 (expected)
Aquamarine Power/Oyster				300-600	2009 (expected)
Aquamarine Power/Neptune			2009-2012	2400	
SMD Hydrovision/TiDEL			Unknown	500	
Wave Dragon ApS/Wave Dragon			2008 (expected)	4000-7000	
Wave Energy AS/Seawave slot cone generator			2008 (expected)	200	
Biopower Systems/Biowave and Biostream			2009 (expected)	250	
AW Energy/Wave Roller			2007	13	
Fred Olsen Renewables/FO3		1:3 Prototype.	Full scale device may be deployed in 2010 at wavehub		
Ecofys/Wave Rotor		1:10 Prototype built in 2002			
Ocean Navitas/ Aegir Dynamo		2kW prototype at NaREC.	1MW device due at EMEC (date unknown)		
Green Ocean Energy Ltd/Ocean Treader		Currently fund raising to allow a full size prototype to start offshore testing in 2010.			
Research Groups					
Supergen Marine	A UK marine energy university consortium focusing on the exploitation of marine energy resources.				
Ecofys	A Dutch research and consultancy company with a focus on developing experimental techniques for the marine energy industry				
UK Energy Research Centre	Focal point for UK research on sustainable energy				
Various universities					
Electric Power Research Institute	US based institute with marine energy forum				

Source: SQW Energy

Figure 8.3 below provides a snapshot of the research, development and commercialisation activities by country. The effect of government support schemes for wave and tidal stream energy can be seen from the number of systems being developed in the UK where the government has introduced specific regimes for development of marine energy.

Figure 8.3: Ocean energy-related research, demonstration and commercial activities by country (December 2008)



Source: IEA-OES, 2009

The recent announcement of the Saltire Prize challenge by the Scottish Government could lead to a significant acceleration of the global marine energy sector if the challenge is met in the timeframe envisaged (awarding of the prize by the end of 2015). The Saltire Prize challenge reads as follows:

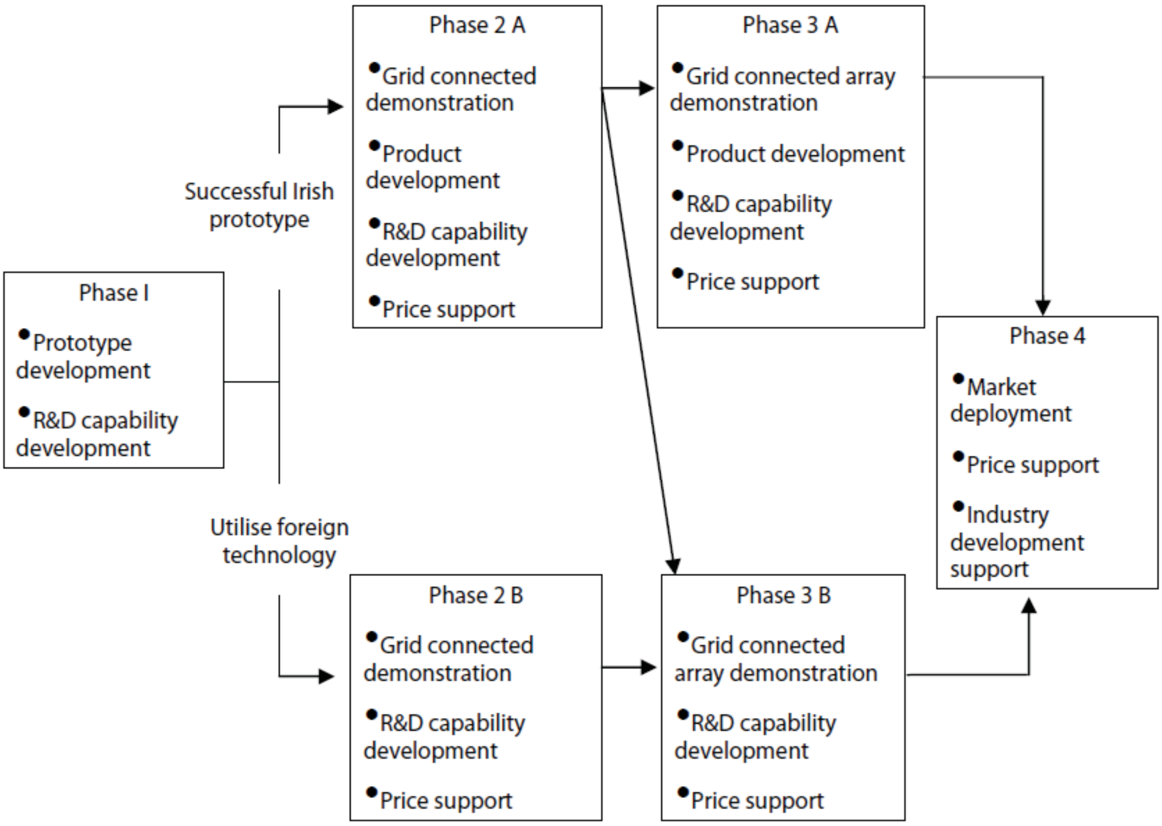
"£10 million will be awarded to the team that can demonstrate in Scottish waters a commercially viable wave or tidal energy technology that achieves a minimum electrical output of 100 GWh over a continuous 2 year period using only the power of the sea and is judged to be the best overall technology after consideration of cost, environmental sustainability and safety." (Scottish Government, Dec 2008)

8.1.2 Irish Context

The Irish Government has developed a strategy to accelerate the development of wave and tidal energy. The strategy document recognises that the development of an ocean energy sector could create a manufacturing industry in Ireland, reduce reliance on imported fossil fuels and help to reduce greenhouse gas emissions. With this in mind, the decision was taken to commit to a significant research and development programme for ocean, wave and tidal, so that Ireland would be well placed to become a technology leader in the field of ocean energy.

The strategy is split into four phases, summarised in Figure 8.4 below. Phase 1 ran from 2005 to 2007; Phase 2 runs from 2008 to 2010; Phase 3 between 2011 and 2015 and Phase 4 from 2016.

Figure 8.4: Four Phase Ocean Energy Strategy for Ireland



Source: DCENR, 2005

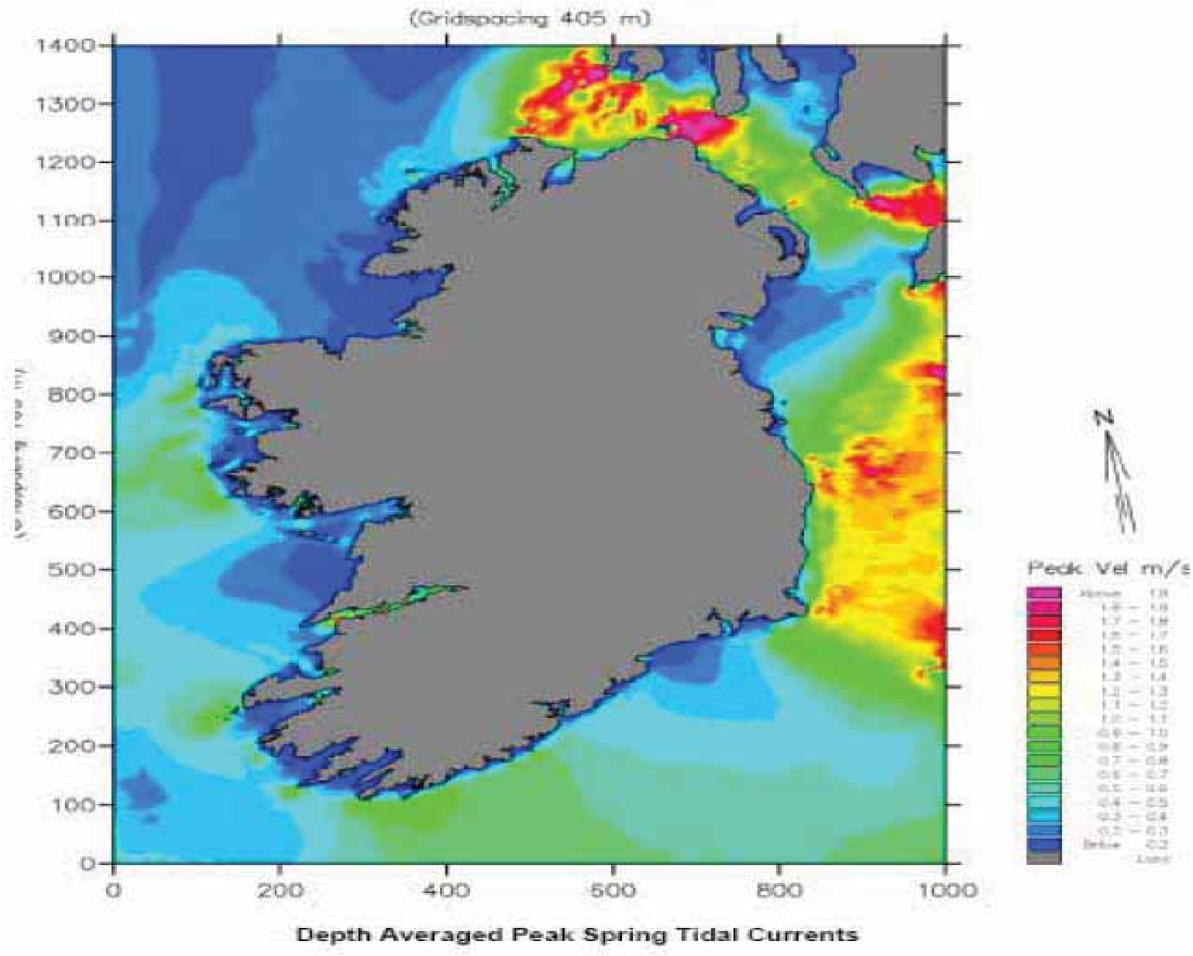
Progression of the strategy for Ireland is being observed and in a recent presentation by SEI and the Marine Institute[1] the following developments were noted:

- Plans for a Grid-connected Wave Energy Test Site are being finalised;
- Plans for a Tidal Test Site are being developed;
- An industry support scheme is being put in place;
- Research and technical support is being enhanced; and
- An attractive price support scheme is in place (REFIT).

The Irish ocean energy strategy acknowledges that, while the total theoretical marine current resource is estimated at around 230 TWh/year, the current estimated level of viable resource of 0.915 TWh/year represents just 2 per cent of the projected energy consumption in Ireland in 2010. A map of the estimated tidal resource around Ireland is provided in Figure 8.5 below.

1 Renewable Energy Association (REA), Eoin Sweeney presentation,2008, *Ocean B Energy Developments in Ireland*

Figure 8.5: Estimate of Ireland's tidal resource



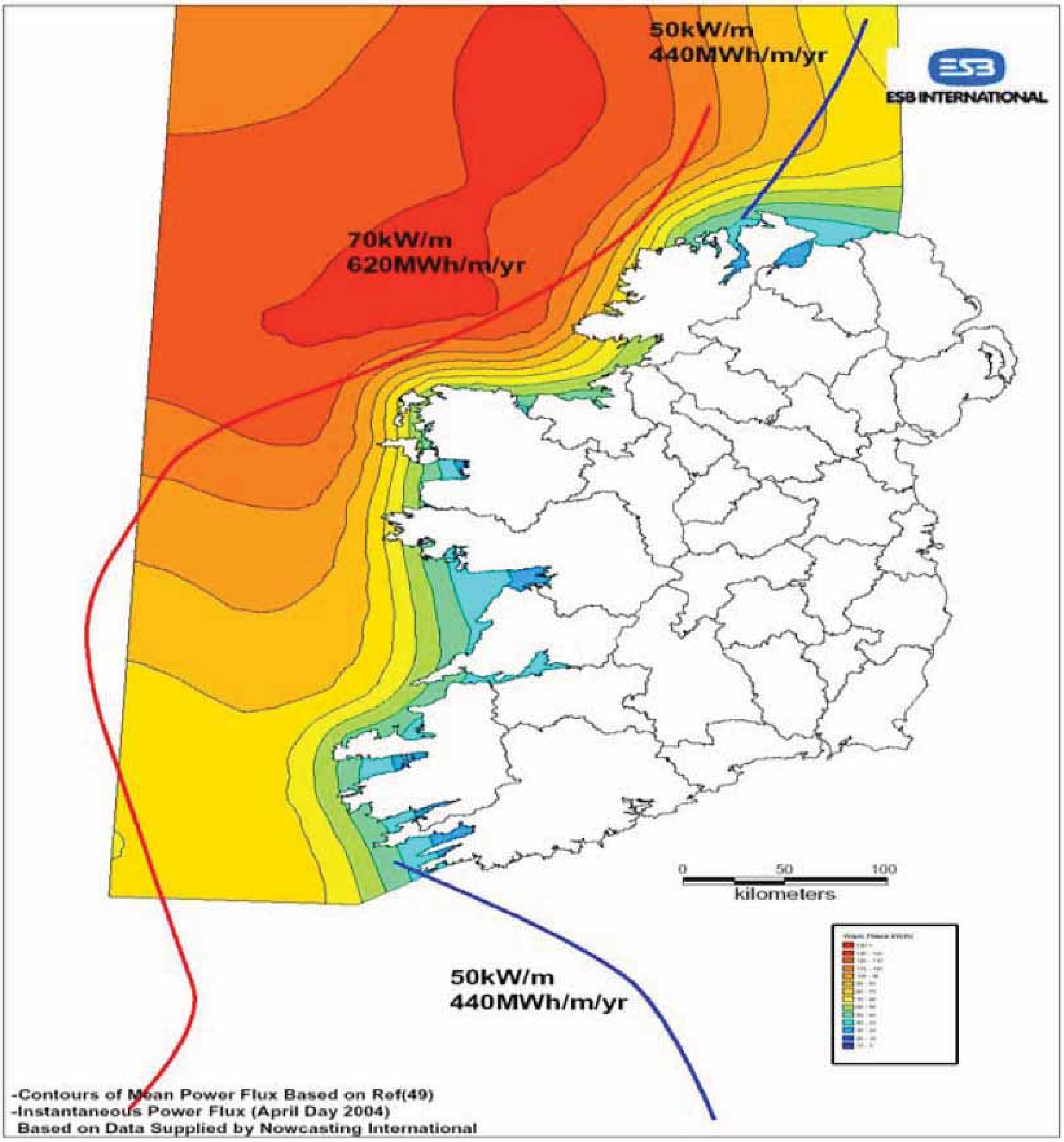
Source: Marine Institute Ireland, 2007

In 2005 research into wave resources in Ireland was also published which indicated that a theoretical wave energy resource of up to 525 TWh/year existed, scaled down to a viable resource of approximately 21 TWh/year[2]. A map of the average wave power around Ireland (developed by Pontes et al, 1998[3]) is shown in Figure 8.6 below.

2 SEI Marine Institute, 2005, *Accessible Wave Energy Resource Atlas: Ireland 2025*

3 Pontes, M.T. et al, 1998, *The European Wave Energy Resource*, 3rd European Wave Energy Conference, Patras, Greece

Figure 8.6: Indicative Wave Resource Levels in Annual MWh/m



Source: DCENR, 2005

In the 2007 Energy White Paper the Irish Government set an initial ambition of at least 500 MW of installed ocean energy capacity by 2020, with an interim target of 75MW by 2012[4].

4 Marine Institute 2007, *Summary Status of the Ocean Energy Development Strategy*

8.2: Marine as an energy source

Marine energy, both in its wave and tidal form, is a renewable energy resource which will be available indefinitely. Waves are created mainly as a result of solar irradiation (by way of sea water temperature differences and wind); tides are created by the gravitational force of the moon. Neither will diminish over time. Wave and tidal resources are indigenous to Ireland and are a free energy source.

Wave and tidal devices in development are expected to have capacity factors within the range 30- 40 per cent[5], similar to the capacity factors associated with wind energy.

5 Electric Power Research Institute (EPRI), 2007, *Power and Energy from the Ocean Energy Waves and Tides: A Primer,* http://www.oceanrenewable.com/wp-content/uploads/2008/03/power-and-energy-from-the-ocean-waves-and-tides.pdf

EPRI, 2006, System Level Design, Performance, cost and Economic Assessment – Tacoma Narrows Washington Tidal In-Stream Power Plant

EPRI ,2004, System Level Design, Performance, cost and Economic Assessment for San Francisco California Pelamis Offshore Wave Power Plant

8.3: Marine in the energy system

8.3.1 Delivered energy cost

Information on the delivered costs associated with marine energy is predominantly based on estimates and projections due to the early stage of development of the commercial industry. A summary of some recent cost estimates (current and future) are provided in Tables 8.1 and 8.2 below.

Table 8.1: Current estimates of levelised costs for the marine energy sector

Source of estimate (year)	Wave (€/ GJ)	Tidal stream (€/ GJ)
Carbon Trust (2006)	42 - 153 (10 MW installation)	31 - 63 (10 MW installation)
SEI (2004)	35 (5 MW installation)	29 (2 MW installation)
UK DTI (2007)	43 - 99 (installation unspecified)	43 - 82 (installation unspecified)

Source: As stated in table

Table 8.2: Future estimates of levelised costs for the marine energy sector

Source of estimate (year)	Wave (€/ GJ)		Tidal stream (€/ GJ)	
	2010	2020	2010	2020
UK DTI (2007)	43 - 98	33 - 75	42 - 81	32 - 62

Source: As stated in table

Whilst the values are wide ranging, the general theme coming out of analysis of cost estimates is that costs are expected to fall for both wave and tidal technologies as knowledge of deployment and operational experience improves, accompanied by future innovations in the enabling support technologies such as power converters, moorings and materials science. There also appears to be some consensus that the cost of electricity generation from tidal stream is expected to be cheaper than that from wave power in the future.

8.3.2 Marine energy – Conversion Technologies

The UK Energy Research Council developed a roadmap to assist the development of the UK marine energy sector, based on a goal of 2 GW of installed capacity in UK waters by 2020. They predict that new devices will continue to be developed at small scales with more established (sea demonstrated) devices being adapted and improved up to and beyond that date. Their view is that by around 2015 there will be industry consensus around families of wave and tidal energy devices to be further refined and improved[6].

OpenHydro are one of the leading Irish marine energy companies with global rights to a tidal stream technology developed in the United States. In May 2008 OpenHydro became the first tidal energy company to complete the connection of a tidal turbine to the UK national grid and commence electricity generation[7]. They have since agreed to develop an offshore tidal farm connected to the French electricity network from 2011, which is expected to create 30 Irish jobs for manufacturing the turbines[8]. However, at present there are no plans announced by the company to develop tidal projects within Ireland.

Other Irish companies in the marine energy sector include;

- Wavebob, who have developed a wave energy converter. Although no full scale Wavebob device has been deployed the company is now working with a Swedish electricity utility and intends to begin full-scale operations in Ireland by 2010[9].
- Hydam who developed the McCabe wave pump in the 1980s and have recently begun a retesting programme.
- Ocean Energy Ltd who are developing an oscillating water column duct (currently at prototype stage).

8.3.3 Policy and regulation

The International Energy Agency's Ocean Energy Systems (IEA-OES) group highlighted that, at present, most countries have complicated procedures for licensing and development permits for marine renewables. In addition, in order to assess performance, internationally recognised guidelines and standards are also needed[10].

The marine energy industry in Ireland is at an early stage of development but is likely to follow a similar regime to the existing offshore wind industry.

There is a significant level of support for the marine energy sector in Ireland. As part of Phase 2 of the development strategy, the Minister for Communications, Energy and Natural Resources announced in January 2008 a policy support plan for ocean energy including:

- €1 million towards a National Ocean Energy facility at University College Cork;
- €2 million to develop a grid-connected wave energy test site;
- €2 million in grants under the Ocean Energy Prototype Fund to help developers to make their devices commercial;
- the introduction of a new feed-in-tariff for wave energy of €220 per megawatt hour; and

6 UKERC, 2008, *Marine Renewable Energy Technology Roadmap*

7 OpenHydro Press Release (27/05/08) http://www.openhydro.com/news/270508.html

8 OpenHydro Press Release (21/10/08) http://www.openhydro.com/news/211008.html

9 Wavebob, 2008, "Latest News". http://www.wavebob.com/latest_news/wavebob_plans_wave-farm_for_the_west_of_ireland.php

10 IEA-OES, 2008, Harnessing the Power of the Oceans, Energy Technology Bulletin, Issue No. 52

- €500,000 to establish an Ocean Energy Development Unit within Sustainable Energy Ireland (National Development Plan, 2008).

A positive stance has been adopted by the Irish Government in respect of development of the wave and tidal sector and it has been assumed that this support will be maintained out to 2030 for the purposes of this study.

8.3.4 Supply chain and infrastructure resilience

The physical infrastructure for wave and tidal technology is considered to be no more complex than other renewable electricity generating technologies.

Reliability of emerging technology and the ability to survive in harsh climatic environments are key challenges for marine renewables, due to the financial and reputational consequences of catastrophic failures and/or long periods of unavailability. Deployment of existing technology has, to date, involved lengthy deployment periods and suffered unexpected breakages and failures prior to becoming operational. However, most developers of marine energy devices are focussed on overcoming these challenges (as it is in their interests to do so given the existing lack of dominance of any particular technology in the market).

8.3.5 Market context in Ireland

The existing marine energy resource around Ireland is yet to be tapped into on a significant scale as the market awaits the technological advances required to commercialise the sector.

Similar to the problems experienced by the onshore wind industry in 2003 when the Transmission System Operator issued a moratorium on wind power grid connections to allow time to address the technical challenges associated with accommodating wind power penetration levels beyond the amount then committed, grid connection in Ireland may become an issue for marine generators as the technological barriers at the level of the electrical generation equipment that are currently causing bottlenecks in deployment are overcome.

Whilst the resource is indigenous and free there will be some sites around Ireland more suited to marine energy generation than others. It may be that different technologies are suited to different sites. However, as the technology improves it is expected that the number of devices in the market will reduce as favourites emerge. In Ireland this may create an initial rush to inhabit the most profitable sites followed by a drop off in uptake as companies have to decide on whether to and how to tackle deployment of devices in less suitable locations.

8.3.6 Market volatility

The market for wave and tidal devices is, like the technology itself, at an early stage of development. The existing market cannot support any large scale demand for electricity generated from marine resources. In addition, access to the electrical grid for marine energy developments has to be ensured to allow the market to develop. In the recent Eirgrid development strategy document[11] it is estimated that the capacity of the bulk transmission system in Ireland will need to be doubled by 2025 in order to facilitate the necessary increase in renewable generation (and they recognise wave and tidal as playing a part within that timeframe). However, based on the commitments set out in the Eirgrid document, it has been assumed that grid connection issues will not materially impact development of the marine energy sector in Ireland.

8.3.7 Environmental impacts

Tidal energy devices will change tidal movements and could result in negative impacts on aquatic and shoreline ecosystems, as well as navigation and recreation. The few studies that have been undertaken to date to identify the environmental impacts of a tidal power scheme have determined that each specific site is different and the impacts depend greatly upon local geography. Local tides changed only slightly due to the La Rance barrage, and the environmental impact has been negligible but this may not be the case for all other sites. It has been estimated that in the Bay of Fundy, tidal power plants could decrease local tides by 15 cm. It is difficult to estimate the extent to which this will be a problem as natural variations in wind can change the levels of tides by several meters.

Wave power structures have little effect on the ocean environment, but there is a possibility of local ecology being altered by their presence.

11 Eirgrid, 2008, *Grid 25 - A Strategy for the Development of Ireland's Electricity Grid for a Sustainable and Competitive Future*

8.4: Marine energy and climate change

8.4.1 Carbon content of fuel

The wave and tidal energies use the ocean as a fuel and thus the fuel has no carbon content.

8.4.2 Lifecycle carbon footprint

The world's first commercial wave farm will feature the ‘Pelamis’ wave energy converter developed by Ocean Power Delivery. With potential for the manufacture of significant numbers of such devices, there is a need to assess their environmental impact and, in particular, their life cycle energy and carbon dioxide (CO_2) performance.

A University of Edinburgh (2008) study reports on an analysis of the life cycle energy use and CO_2 emissions associated with the first generation of Pelamis converters. With relatively conservative assumptions, the study shows that at 293 kJ/kWh and 22.8 gCO_2/kWh the respective energy and carbon intensities are comparable with large wind turbines and very low relative to fossil-fuelled generation.

Material use is identified as the primary contributor to the embodied energy and carbon with shipping (including maintenance) accounting for 42 per cent. Improving the Pelamis' environmental performance could be achieved by increasing structural efficiency, partial replacement of the steel structure with alternative materials, particularly concrete, and the use of fuel-efficient shipping[12].

According to POST current wave converter devices require about 665 tonnes of steel and emit between 25 gCO_2/kWh – 50 gCO_2/kWh which is roughly equivalent to photovoltaic technologies.

Wave and tidal technologies, however, are still in their infancy and the carbon emission calculations for their life cycle have been on prototypes rather than fully tested commercial systems. While the Pelamis wave energy converter is an example of a success, there appears to be far more troubled examples of prototype testing and proposed concepts than successful commercial devices. It is unlikely that the life cycle carbon emissions will change much during the time period 2010-2020 as the amount produced will increase relative to the amount of materials used in the devices. Post 2030, one would expect there to then be less carbon emitted per kWh as processes improve and the technology improves.

8.4.3 Supply and infrastructure vulnerability

Although wave and tidal technologies are under conditions that are hostile, the changes in climate should not affect the infrastructure as their design at commercial stages should be able to handle any changes in ocean environment.

12 University of Edinburgh 2008, *Life cycle assessment of the Seagen marine current turbine*

8.4.4 Availability change of the resource

With waves being the product of local and distant wind activity and, with wave power proportional to the fifth power of wind speed, changes in wind speed will produce relatively large changes in available wave energy. The rich wave climate off Western Europe is heavily dependent on storm activity in the North Atlantic and there is evidence that storm intensity has been increasing in recent decades; this is backed up by trends in mean and extreme wave heights[13].

Tidal power will not be affected by climate change as the tides are controlled by the moon.

13 University of Edinburgh, 2005, *Life cycle assessment of the Seagen marine current turbine*

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The Irish Energy Tetralemma

Fuel Report 9: Geothermal

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ There is no fuel input cost associated with Geothermal power. ▪ Ireland does not have any easily accessible geothermal energy resources, but similar to other countries it can pursue access to deeper sources. A geothermal atlas for Ireland shows good resource at 2.5 km depth.
Delivered energy cost	▪ Geothermal energy is among the more cost-competitive renewable technologies, on a par with bio-gas and solar heat, but is considerably more expensive than fossil-fuel derived energy. ▪ The main costs associated with geothermal power occur during the exploration stage, primarily as it is characterized by a high degree of uncertainty. Approximately 50 per cent of the cost of a geothermal power plant is related to the identification and characterisation of reservoirs, and to the drilling of production and reinjection wells. Some 40 per cent is spent on the power plant equipment and pipelines, and 10 per cent is spent on other activities. ▪ The operating costs of geothermal power plants are very low due to the low cost of the fuel.
Policy & Regulation	▪ There is limited policy and regulatory support for geothermal energy in Ireland. ▪ By association, it is and will be receiving support under the renewables objectives and targets for Ireland. ▪ At the same time there are no specific barriers identified. A generic disincentive would be the development and deployment permission regulations associated with environmental impacts and local planning rules.
Market context in Ireland	▪ Geothermal energy is not part of the energy mix in Ireland and as such there is no developed market. ▪ This poses certain market barriers in terms of confidence in and experience/familiarity with the technology. ▪ A particular barrier is the need for bespoke and typically local heat distribution infrastructure which is capital intensive and jeopardises the economic viability of a scheme.

Security of supply

Import dependence	▪ Geothermal energy is an indigenous resource and as such Ireland is not dependent on imports. ▪ Currently it is not part of the national energy mix.
Fuel place of origin	▪ Geothermal energy is an indigenous resource for Ireland and therefore considered highly secure.
Supply and infrastructure resilience	▪ Geothermal energy is associated with a fairly robust and resilient infrastructure. ▪ The supply chain is also resilient as it mainly comprises equipment supply (and associated services).
Market volatility	▪ Geothermal energy is a niche technology and has not been subject to market stress - this is likely to continue in the future.
Energy availability and intermittency	▪ Geothermal energy as a resource is constant and non-intermittent. ▪ Availability of the plant is very high at 95 per cent.

Sustainability

Fuel longevity	▪ Geothermal energy is a renewable resource, which fully replenishes itself and will be available indefinitely.
Environmental Impacts	▪ The environmental impact of geothermal energy is negligible. ▪ Some geothermal plants do produce some solid materials, or sludges, that require disposal in approved sites. Some of these solids are now being extracted for sale (zinc, silica, and sulfur, for example), making the resource even more valuable and environmentally friendly/sustainable.

Climate change

Carbon content	▪ Geothermal energy is considered a carbon-free energy source.
Lifecycle carbon footprint	▪ The carbon footprint of geothermal energy is very low at approximately 7.8 gCO_2/kWh. This comprises 6.5 gCO_2/kWh for stack emissions during operations and 0.98 gCO_2/kWh are emitted during construction.
Supply and infrastructure vulnerability	▪ There is very limited perceived impact on geothermal infrastructure due to climate change.
Availability change	▪ Climate change will not have an impact on the geothermal resource.

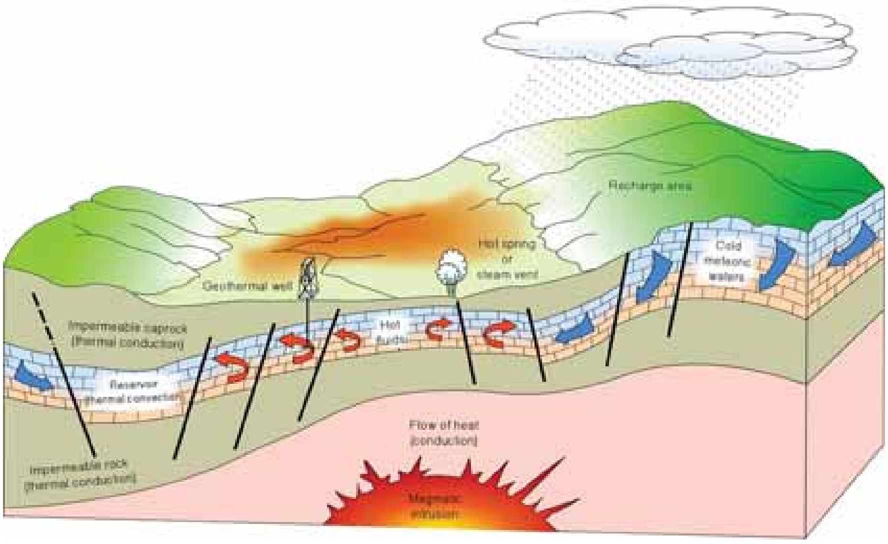
9.1: Geothermal energy: the basics

Geothermal energy is the heat from the Earth's core. Geothermal resources range from shallow ground to hot water and rock several miles below the surface, and even further down to the extremely hot molten rock, called magma, see Figure 9.1.

Geothermal energy is used for both heat and electricity generation as follows:

- Direct use of hot water: geothermal reservoirs of low to moderate temperature water (20˚C to 150˚C) provide direct heat for residential, industrial, and commercial uses.
- Power generation: deep wells can be drilled into underground reservoirs to tap steam and very hot water that then drive turbines which in turn drive electricity generators. There are three types of power plants operating today:
    - Dry steam plants – these use geothermal steam to turn turbines.
    - Flash steam plants – these pull deep, high pressure hot water into lower-pressure tanks and use the resulting flashed steam to drive turbines.
    - Binary cycle plants – as above, but these pass moderately hot geothermal water by a secondary fluid with a much lower boiling point than water.

Figure 9.1: Sources of geothermal energy



Source: www.treehugger.com

Shallow geothermal heat (10-100 m of depth) can be extracted as low grade heat and put through Ground Source Heat Pumps (GSHP) which supply space heating. This ground heat however is effectively solar radiation stored in the ground as opposed to genuinely geothermal energy. Its application is very site-specific and smaller-scale and is not covered in this study.

9.2: Geothermal energy as an energy source

9.2.1 Fuel longevity

Geothermal energy is classified as a renewable resource as it originates from the earth's hot core, which will continue to generate and emit heat almost indefinitely. Thus, the geothermal energy supply is continuously renewed, although this renewal takes place at a varying rate depending upon the nature of the geothermal reservoir (Orkustofnun, 2006[1]). The long term sustainability of geothermal production has been demonstrated at the Lardarello field in Italy since 1913, at the Wairakei field in New Zealand since 1958, and at The Geysers field in California since 1960. Declines of pressure and production have been experienced at some plants, and operators have begun re-injecting water to maintain reservoir pressure. The City of Santa Rosa, California, pipes its treated wastewater up to The Geysers to be used as reinjection fluid, thereby prolonging the life of the reservoir while recycling the treated wastewater.

Geothermal energy is also independent of weather conditions, contrary to solar, wind, or hydro applications. It has an inherent storage capability and can be used both for base-load and peak power plants.

9.2.2 Global availability and harnessing

Estimates of global geothermal capacity vary greatly. The Geothermal Energy Association reports that there is 35,448 and 72,392 MW of worldwide electrical generation capacity. However, MIT[2] reports with Enhanced Geothermal Systems (which allow for geothermal resources 10km deep to be exploited), the potential generating capacity in the US alone is 100 GWe.

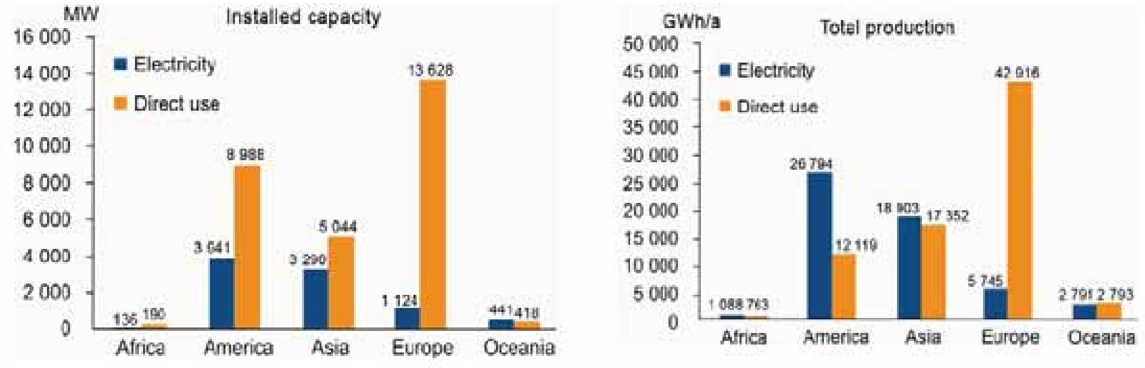
In terms of harnessing geothermal energy, worldwide utilisation in 2004 was about 55 TWh of electricity and 76 TWh for direct heat use. Figure 9.2 shows the installed capacity and the energy produced by geothermal by continent (WEC, 2006[3]).

1 National Energy Authority of Iceland, 2006

2 MIT, 2006, *The Future of Geothermal Energy*

3 Only 2004/7 listed in Appendix

Figure 9.2: Geothermal energy use for electricity - installed Capacity and total production by continent



Source: WEC, 2006

Table 9.1 shows the extent of its use in 4 specific countries where the resource and the utilisation rate of the resource are high. Significant geothermal resources have been identified in some 90 countries. Electricity is produced from geothermal energy in some 25 countries. Five of these countries obtain 15-22 per cent of their national electricity production from geothermal energy.

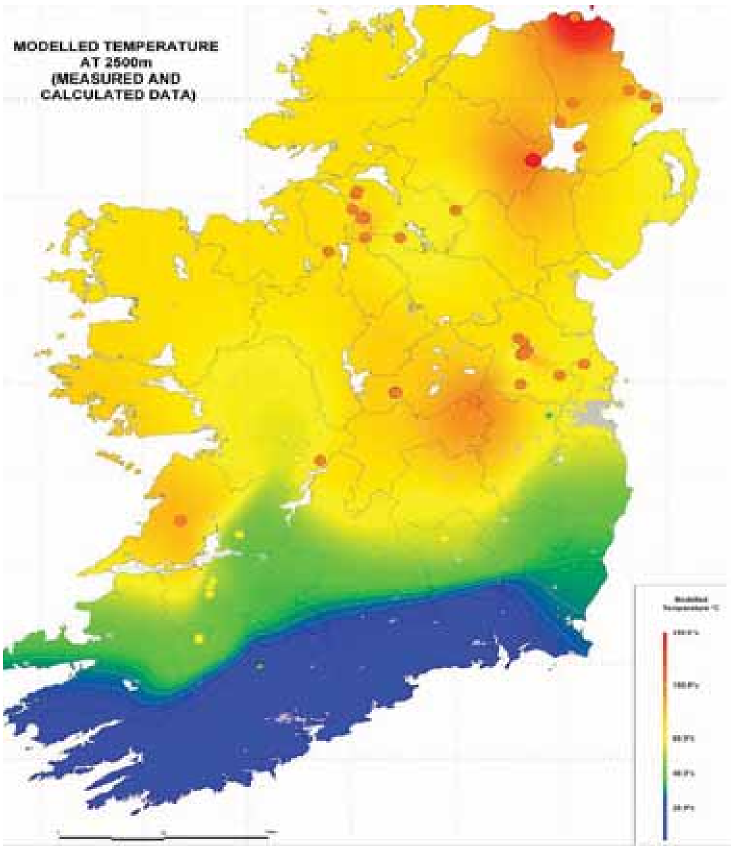
Table 9.1: Geothermal Energy in an international context

Country	Utilisation	Source
USA (California)	The USA possesses a huge geothermal resource, estimated at some 50,000 MW, located largely in the western half of the country. The largest group of geothermal power plants in the world is located in The Geysers, a geothermal field in California. Geothermal heat suitable for direct utilisation is far more widespread through the US, ranging from New York State in the east to Alaska in the west. At end-2004, a total of 617 MW installed capacity was used for fish and animal farming, greenhouse heating, bathing and swimming, district heating, space heating, agricultural drying, industrial process heat and snow melting.	WEC (2006)
Iceland	In 2002 54.7 per cent of Iceland's primary energy use was from geothermal sources. In 2004 Iceland had 200 MW of installed geothermal capacity and generated 1,483 GWh of electricity from this source, which meant that 14.2 per cent of total electricity generation was from the earth. However, geothermal energy is used mainly for heating purposes.	Orkustofnun (2005) Orkustofnun (2006)
Japan	By the end of 2003, installed electricity capacity stood at 535.25 MW. The country's geothermal potential is estimated to be in the order of 24.6 GW. Only a small fraction of this potential has been used to date and until ways of tapping Japan's deep resources can be developed, this situation will prevail. In 2005 it was estimated that total installed capacity for direct use of heat totalled more	WEC (2006)

	than 400 MW (excluding recreational hot-spring bathing).	
Italy	Italy is one of the world's leading countries in terms of geothermal resources. By the end of 2004, total Italian installed geothermal capacity stood at 790.5 MW. Power generation potential is almost fully tapped, so major efforts are being made in deep drilling and in keeping output at 5 500-6 000 GWh/yr through re-injection and well stimulation. Of the 600 MWt of installed heat capacity at end-2004, 58 MWt were used for industrial space heating, 74 MWt for district heating, 94 MWt for greenhouse heating, 92 MWt for fish farms, 10 MWt for industrial process heat, 159 MWt for bathing and swimming and 120 MWt for ground-source heat pumps.	WEC (2006)

An SEI review of geothermal capacity in Ireland has indicated temperature ranges between 28ºC – 45ºC to the south to 64ºC – 97ºC to the north at a depth of 2,500m (see Figure 9.3). This indicates significant geothermal sources with the potential for commercial development, although exact quantification of the resource will require additional assessment in areas of interest (SEI, 2004)[4].

Figure 9.3: Geothermal energy in Ireland - Temperature at a depth of 2.5km



Source: SEI

4 Sustainable Energy Ireland (SEI), 2004, *Geothermal Resource Map*

Geothermal energy is an indigenous ambient and free resource to Ireland (and cannot be imported) and is therefore a highly secure source of supply.

Currently there is no installed geothermal capacity in Ireland – neither for heat nor for power generation. Any problems with procuring the energy sources fall within Irish communities and preferences for using geothermal energy. There doesn't appear to be any real barriers to using the resource other than technological ones. However, to mitigate potential resistance from communities, public awareness campaigns should take place as a matter of course.

Geothermal energy is a constant and non-intermittent source and can be used quite effectively in both summer and winter conditions. The plant capacity factor is typically 95 per cent which means that geothermal energy is available most of the time. There is a relatively low downtime for maintenance and potential stoppages. Over the period to 2030 the availability of geothermal will remain constant.

9.3: Geothermal energy in the energy system

9.3.1 Delivered energy cost

It is expected that any future geothermal energy capacity in Ireland will be geared up for heat supply and not electricity due to the much higher cost if it is used for power generation. Levelised energy costs however are more abundant for its electricity application than for heat. This section provides the evidence for both applications.

Electricity generation

According to EUSUSTEL[5], the installation costs of geothermal power plants range from €640,000 to €2,400,000 per MW installed and the resulting electricity cost from 16 to 80€/MWh. A potential economic drawback of geothermal power is the high capital cost and uncertainty associated with exploring geothermal sites, particularly in comparison to other energy sources. Approximately 50 per cent of the cost of a geothermal power plant is related to the identification and characterization of reservoirs, and to the drilling of production and reinjection wells. About 40 per cent is spent on generation equipment and pipelines while 10 per cent is spent on other activities[6]. The IEA identifies drilling as the main cost and reports that it accounts for up to between one-third to one-half of the cost of the entire project[7]. The operating costs of geothermal power plants are very low due to the low cost of the fuel.

- Infrastructure requirements (access roads, water and power services, proximity to adequate port facilities, and proximity to a city). In isolated locations the infrastructure may be a significant part of the total cost.
- Climatic conditions at the site. As with all types of power plants their cost and performance is dependent on the local climatic conditions. Low ambient wet bulb temperatures for example can lead to a less costly cooling system and a more efficient plant.
- Topography of the site. If the geothermal resource is located in difficult terrain, civil development costs will be higher, pipelines may be more complex, of longer length with greater pressure drops and overall development costs may be higher.
- Environmental constraints on the siting, construction and operation of the geothermal power station can often result in increased development cost.

Geothermal heat

Figure 9.4 below provides the levelised cost range for both heat ('Geothermal Heat') and electricity ('Geothermal'), along several other renewable technologies (Pöyry 2008[8]).

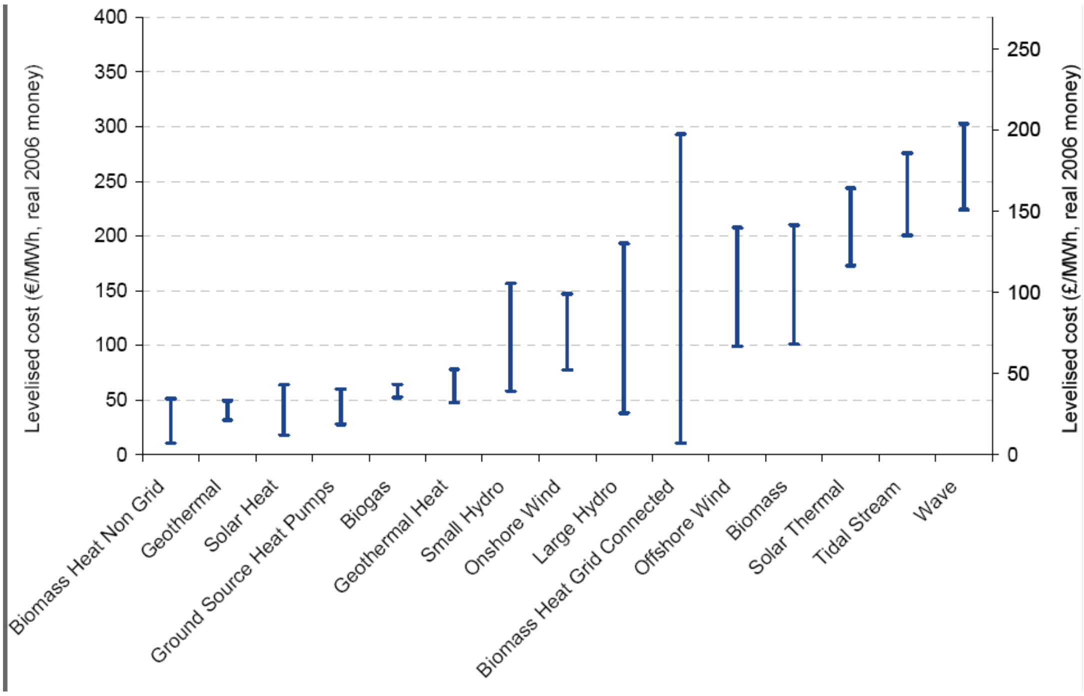
5 EUSUSTEL, 2004, *Geothermal Power Production*

6 EUSUSTEL, 2004, *Geothermal Power Production*

7 IEA, 2008a, *Energy Technology Perspectives 2050*

8 Pöyry, 2008, *Compliance Costs for Meeting the 20% Renewable Energy Target in 2020*,Report to BERR

Figure 9.4: Levelised energy costs of geothermal heat and electricity



Source: Pöyry 2008

According to the University of Colorado (2006), the cost of using geothermal energy – relevant to both heat and power – can be further broken down by the following factors:

- The temperature and depth of the resource. A shallow resource means minimum drilling costs. High temperatures (high enthalpies) mean higher energy capacity.
- The type of resource (steam, two-phase or liquid). A dry steam resource is generally less expensive to develop as reinjection pipelines, separators and reinjection wells are not required.
- The chemistry of the geothermal fluid. A resource with high salinity fluids, high silica concentrations, high gas content, or acidic fluids can pose technical problems which may be costly to overcome.
- The permeability of the resource. A highly permeable resource means higher well productivity, and therefore fewer wells required to provide the steam for the power plant.
- The size of the plant to be built. As with most types of plant, economies of scale means large power plants are generally cheaper in €/MW.
- The technology of the plant. There are a number of geothermal power technologies available, each technology has advantages and disadvantages and different cost structures.

All the costs that have been reported in the literature are presented in Table 9.2.

Table 9.2: Costs of geothermal energy (delivered cost)

Usage	2010	2020	2030
Heat	3- 8 €/toe (EGEC) 50 - 80 €/MWh (Pöyry)	3 - 6 €/toe (EGEC)	3 - 6 €/toe (assumed no change)
Electricity	0.16 – 0.8 €/kWh (EUSUSTEL) 0.02 - 0.10 US$/kWh (WEC) 0.40 - 1.0 US$/MWh (IPCC) 0.02 - 0.11 US$/kWh (IEA) 0.025 – 0.10 US$/kWh (Leeds)		0.3 - 0.8 US$/kWh (IPCC)

Source: as indicated in the table

9.3.2 Geothermal Energy – conversion technologies

As heat pumps are too small to consider in this project and electricity generation using geothermal energy is not appropriate in the Irish context the focus here is on other geothermal heating systems.

Enhanced Geothermal Systems (EGS), attempts to produce heat and electricity by harnessing the energy from hot rock deep below the earth's surface, expanding the potential of traditional geothermal energy by orders of magnitude. Deep rock with the same flow rate as a conventional well can yield ten times as much power because the steam conditions are much more favourable. However, drilling costs rise exponentially with drilling depths. Drilling to a depth of 5km has historically cost USD 5 million and drilling costs have doubled from 2004 – 2009. This might ease in time, and if the technology does mature by 2030, it is assumed that the drilling costs are low enough to make the cost of producing heat from deep rock competitive.

Several advanced energy-conversion technologies are becoming available to enhance the use of geothermal heat, including combined-cycle for steam resources, trilateral cycles for binary total-flow resources, and remote detection of hot zones during exploration, absorption/regeneration cycles (e.g., heat pumps) and improved power-generation technologies. Improvements in characterising underground reservoirs, low-cost drilling techniques, more efficient conversion systems and utilisation of deeper reservoirs are expected to improve the uptake of geothermal resources as will a decline in the market value for extractable co-products such as silica, zinc, manganese and lithium. (IPCC, 2007[9])

In 2030 it is assumed that the costs are the same as these new technologies effectively become competitive at the same level as existing technologies.

9.3.3 Policy and regulation

No specific and significant policy barriers to developing geothermal energy applications in Ireland can be identified. The planning system will pose certain restrictions and procedures when assessing the impacts of schemes, including environmental impacts. This is particularly in light of the heat application of geothermal energy where heat pipelines will be required. This application is also relatively local in nature and opposition from communities could possibly be expected.

Direct heat supply is not strongly developed in Ireland and whilst no particular restrictions apply, there could be generic concerns manifesting themselves as policy barriers in terms of health & safety and security. These are also related to the fact that the nature of geothermal technology is to interact with the ground water and aquifers, which in practice are indirect and would not cause issues.

At an EU level there is no specific policy or regulation encouraging the use of geothermal energy. However, there are a range of renewable energy objectives and targets which will have an implication for geothermal energy – they will stimulate the development of schemes and uptake of the technology:

- Renewable targets for 2020 – 20 per cent of total primary energy supply (TPES).
- Improving energy efficiency – 8 per cent improvement by 2015 compared with 1995.
- EU Emissions Trading Scheme – where carbon-saving technologies would help achieve national and sector-specific targets.
- Kyoto Protocol – as above, targets to reduce CO_2 emissions by 8 per cent by 2012.

Ireland has national renewable energy targets, including its share of the EU 2020 target, equivalent to 16 per cent of TPES to be from renewables.

The IEA Geothermal Energy Implementing Agreement provides an international framework for research and development and is looking particularly at deep drilling techniques. Ireland is not a member of this initiative.

Research and development funding for geothermal has declined over the years (see Figure 9.5) primarily as geothermal electrical production has become a mature technology which can compete in today's energy markets without policy support (IPCC, 2007[10]). However, for geothermal heat, which is the most promising application of the resource in Ireland, further support is required. Further research is required to establish the appropriate fiscal and

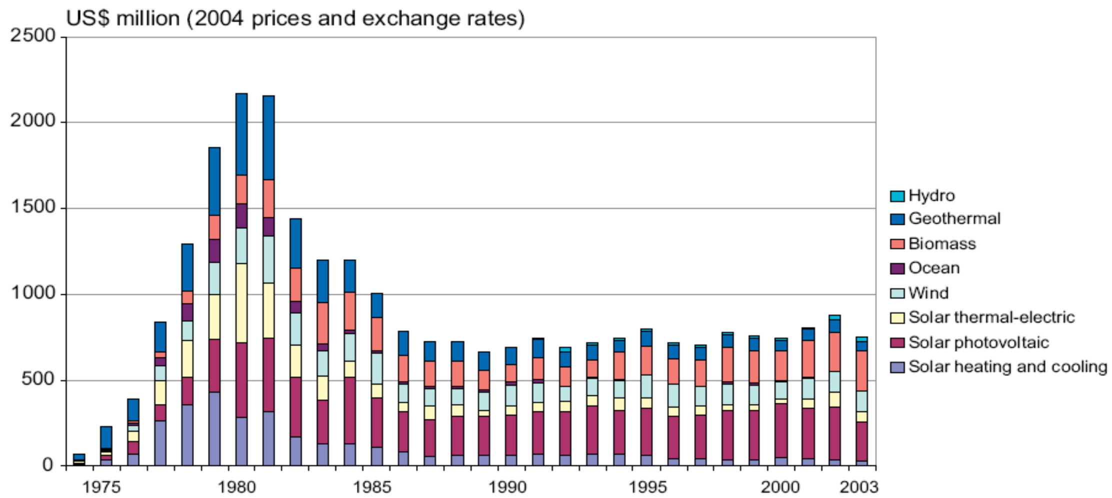
9 Intergovernmental Panel on Climate Change (IPCC), 2007, *Energy Supply – Mitigation of Climate Change*, Working Group 3 Chapter 4

10 Intergovernmental Panel on Climate Change (IPCC), 2007, Energy Supply – *Mitigation of Climate Change*, Working Group 3 Chapter 4

regulatory regime for the exploitation of geothermal energy (SEI, 2004[11]). SEI has recommended that the following actions be undertaken in order to provide the right environment for geothermal heat technologies:

- Standards of equipment;
- Training of technicians;
- Grants to encourage its usage;
- Tax penalties to discourage its neglect;
- Planning requirements to maximise its usage as has been initiated in Cork County development plan (linked to grants system);
- The flagship developments should be highlighted as good practice, e.g. Tralee motor tax office, UCC Arts Museum and the Green Building Temple Bar; and
- Research and development funding in geology, geophysics and engineering would contribute to the grant aid needed to achieve the drilling of the geothermal borehole.

Figure 9.5: Research and Development Funding for Renewable Energy



Source: IPCC

Since 2006, the Irish government has been providing grants from a €65m multi-annual investment programme (Renewable Heat Deployment Program) for ground source heat pumps (GSHP), which are not considered genuine geothermal energy and are not considered in depth in this study.

9.3.4 Market context in Ireland

Geothermal energy is not used in Ireland commercially. This would require the development of a heat distribution network (pipelines and other facilities) – infrastructure that is not

11 Sustainable Energy Ireland (SEI), 2004, *Geothermal Resource Map*

widely available in Ireland. Its main perceived application is for direct heat for local end users. This creates a market barrier to the deployment of geothermal energy as the lack of precedents and local confidence in the technology increases the risks to investors.

Supplying heat also requires a minimum load to make the scheme viable and this is typically achieved in higher-density built-up areas. This requirement is likely to limit the potentially suitable sites and areas for development, which coupled with relatively high exploration costs (for identifying sites with better geothermal resource) and drilling, makes this technology less attractive to the market.

Ground source heat pumps (GSHP)

This type of geothermal energy is not within the scope of this study; however it is worth noting that it is already represented, albeit at a very small scale, in Ireland.

Ireland is well suited for the utilisation of GSHP due to its temperate climate and rainfall levels that ensure good conductivity and year round rain-fall recharge. The current installation rate is increasing rapidly and requires immediate attention to set and maintain high standards of equipment installation and operation.[12] (SEI, 2004).

There are abundant marine and surface water geothermal resources which could be exploited in Ireland, but they need some encouragement for their development. There are two main areas of warm spring development in Ireland, in north Leinster and the Mallow area. They are undeveloped, except for the heat-pump in the Mallow swimming pool, and there is currently available exploitation potential, especially in the light of the recent discovery at Glanworth, Co. Cork.

Current output country wide is approximately 13,500kWh and this is estimated to be climbing by 10,000kWh extra installation capacity per year. No estimates exist for the potential upper limit to geothermal capacity in Ireland.

9.3.5 Supply chain and infrastructure resilience

Geothermal energy for direct heat applications, the more appropriate use in Ireland’s context, is mature and robust and despite certain technical challenges (mainly around deep drilling) it is not considered too complex. The supply chain is not burdened with fuel supplies and is mainly required for the initial development and construction phases.

9.3.6 Market volatility

Geothermal energy is still a relatively niche technology with a small market (compared with other energy sources) and is not represented in Ireland (other than GSHP). It is however growing steadily with an increasingly integrated supply chain – mainly covering the manufacture and supply of equipment. Therefore, its market volatility is very low and only reflects the reality of Ireland having to import products and services for geothermal applications.

12 Sustainable Energy Ireland (SEI), 2004, *Geothermal Resource Map*

9.3.7 Environmental impacts

The environmental impact of geothermal energy is negligible. Some geothermal plants do produce some solid materials, or sludges, that require disposal in approved sites. Some of these solids are now being extracted for sale (zinc, silica, and sulfur, for example), making the resource even more valuable and reducing the environmental impact. Examples of potential threats are described by the Geothermal Energy Association (2007):

- Hydrogen Sulfide (H_2S): Hydrogen sulfide is now routinely abated at geothermal power plants, resulting in the conversion of over 99.9 per cent of the hydrogen sulfide from geothermal co-condensable gases into elemental sulfur, which can then be used as a non-hazardous soil amendment and fertilizer feedstock. Since 1976, hydrogen sulfide emissions have declined from 1,900 lbs/hr to 200 lbs/hr or less, although geothermal power production has increased from 500 megawatts (MW) to over 2,000 MW.
- Mercury: Although mercury is not present in every geothermal resource, where it is present, mercury abatement equipment typically reduces emissions by 90 per cent or more. The comparatively high mercury emitters (two facilities at The Geysers in California) release mercury at levels that do not trigger any health risk under strict California regulations.
- Noise Pollution: Normal geothermal power plant operation typically produces less noise than the equivalent produced by leaves rustling from a breeze, according to common sound level standards, and thus is not considered an issue of concern.
- Water Use: Geothermal plants use 5 gallons of freshwater per megawatt hour, while binary air-cooled plants use no fresh water. This compares with 361 gallons per megawatt hour used by natural gas facilities.
- Water Quality: Geothermal fluids used for electricity are injected back into geothermal reservoirs using wells with thick casing to prevent cross-contamination of brines with groundwater systems. They are not released into surface waterways.
- Land Use: Geothermal power plants can be designed to blend-in to their surroundings more than fossil fired plants, and can be located on multiple-use lands that incorporate farming, skiing, and hunting. Over 30 years, the period of time commonly used to compare the life cycle impacts from different power sources; a geothermal facility uses 404 m^2 of land per gigawatt hour (GWh), while a coal facility uses 3632 m^2/GWh.
- Impact on Wildlife and Vegetation: There will be some effects upon plants and animals; however, these are not seen as hugely damaging.

The implementation of the ExternE methodology in Italy on a geothermal power plant there puts the external cost of producing geothermal energy at 14.47 - 36.98 €/kWh. However, this is dominated by global warming impacts during the carbon emissions of the electricity generation stage. The document does not indicate to what extent the global warming emissions account for the final prices.

If enhanced geothermal system technology is available in 2030 there is the likelihood that the use of drilling technology may cause minor earthquakes like there was in Basel, Switzerland in December 2006 (IEA, 2008[13]). If this was to happen the external costs would be much higher.

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13 IEA, 2008a, *Energy Technology Perspectives 2050*

Furthermore, some aquifers can produce saline fluids that are corrosive and present a potential pollution hazard to freshwater drainage systems and groundwater.

9.4: Geothermal energy and climate change

9.4.1 Carbon content of fuel

The IPCC reports that there are anthropogenic emissions associated with the use of geothermal power; however, there is no methodology available to measure these and estimate these emissions.

9.4.2 Lifecycle carbon footprint

Although we are looking primarily at geothermal from a heat perspective, the data for lifecycle emissions are primarily for the use and operations of electricity plants. SEI does however provide some figures for both electricity and heat applications of geothermal energy. According to their analysis 6.5 gCO_2/kWh are for stack emissions during operations, with 0.98 gCO_2/kWh are emitted during construction. This means that the total life cycle emissions are approximately 7.8 gCO_2/kWh. Their estimate for electricity plants range between 0 - 65.31 gCO_2/kWh for emissions and 9.8 gCO_2/kWh which amounts to a total of 42 gCO_2/kWh. The other values for total emissions are 15 gCO_2/kWh of a plant in Japan (IEA, 2008[14]), 0 - 40 gCO_2/kWh (Geothermal Energy Association, 2007[15]) for plants in the United States, and 90.71 gCO_2/kWh (Climate Change Research Group[16]).

Clearly the emissions from construction are negligible, whereas the emissions during operations contribute most to total carbon emissions. The final value used for the indicator in 2010 is 7.48 gCO_2/kWh as this is the value most relevant to Ireland. For 2020 and 2030 this value is reduced to accommodate improvements in deep drilling technology which will increase the output of electricity and therefore the emissions as a proportion of the total output.

Table 9.3: Lifecycle greenhouse gas emissions in gCO_2/kWh

Application	2010	2020	2030
Heat	7.48 (SEI)	6.00 (SQW assessment)	5.5 (SQW assessment)
Electricity	90.71 (Climate Change Research group) 0 – 40 (Geothermal Energy Association) 42 (SEI)		

14 IEA, 2008a, *Energy Technology Perspectives 2050*

15 Geothermal Energy Association, 2007, *A Guide to Geothermal Energy and the Environment*

16 Climate Change Research, 2003, *Geothermal Energy Reduces Greenhouse Gases*

9.4.3 Supply and infrastructure vulnerability

There is very limited perceived impact on geothermal infrastructure due to climate change.

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The Irish Energy Tetralemma

Fuel Report 10: Hydropower

August 2010

Forfás

Table of Contents

This report is one of eleven fuel-specific reports, produced under the framework of the Energy Tetralemma Index for Ireland. The eleven reports comprise: Coal, Petroleum, Natural Gas, Peat, Biomass, Wind, Solar, Marine, Geothermal, Hydro and Nuclear.

Executive Summary

Competitiveness

Fuel Cost	▪ Hydropower is a free renewable resource. ▪ Ireland's economic hydro resource has largely been tapped and there is limited scope for further exploitation, which will be confined to small-scale schemes.
Delivered energy cost	▪ Hydroelectricity is among the cheapest renewable energy sources, but is more expensive that most fossil fuels. ▪ Hydropower costs are between 2-8 €-cent/kWh and this does not appear to decrease over time. ▪ Hydropower is characterised by a major capital investment cost, a low operating cost due to a high amount of automation, and no fuel cost except with pumped storage facility. The development of a new hydroelectric facility is capital intensive and construction typically takes place over a long period of time. However, since the lifetime of hydro plants tend to be quite long the depreciation costs are very low or nil which means that the delivery costs tend toward the operating costs of the plant.
Policy & Regulation	▪ There is limited direct policy and regulatory support for hydro energy in Ireland, although the existence of many hydro schemes means that barriers are not particularly onerous. ▪ A generic disincentive would be the development and deployment permission regulations associated with environmental impacts and local planning rules. ▪ The users of hydropower are encouraged by the EU RES target and REFIT (feed-in tariff).
Market in Ireland	▪ Ireland has largely reached its Hydro capacity; new developments in this area will typically be small hydro projects (where there is some unexploited potential) and retrofits to existing hydro plants.

Security of supply

Import dependence	▪ Hydro is an indigenous resource and as such Ireland is not dependent on import. ▪ Hydro comprises less than 1 per cent of the national energy mix and 7 per cent of installed electricity capacity.
Fuel place of origin	▪ This is an indigenous energy source to Ireland and therefore highly secure.

Supply and infrastructure resilience	▪ Whilst there is perceived vulnerability of infrastructure in terms of reservoir leaks there are virtually no reported incidents and hydro is considered highly resilient.
Market volatility	▪ There is no fuel market (it is a free renewable resource) and equipment supply is well-established and secure.
Energy availability and intermittency	▪ Hydroelectricity is essentially an intermittent source of energy due to fluctuating river flows and it is often used to meet peak demand. ▪ However, availability is managed and increased by way of reservoirs and pumped storage schemes[1].

Sustainability

Fuel longevity	▪ Hydro is a renewable resource, which fully replenishes itself and will be available indefinitely.
Environmental impacts	▪ Hydro has one of the lowest costs of environmental externalities. ▪ The overall impacts of construction and dismantling play a bigger part on the environment then the actual running of the plant. The most important feature of the hydro fuel cycle is its site specificity. Damages are mostly produced on the immediate local environment and its conditions determine the type and scale of impact. ▪ In terms of specific ecological effects, these occur during the plant operation, including species distribution and migration due to controlled river flow, etc. The external cost of hydro has been calculated at between 0.04 – 6 €-cent/KWh.

Climate change

Carbon content	▪ Hydro energy is considered a carbon-free energy source.
Lifecycle carbon footprint	▪ The carbon footprint of hydro is very low, typically due to construction and is reported to be approximately 25 g CO_2/kWh.
Supply and infrastructure vulnerability	▪ Hydro is expected to be one of the most affected fuels, in relative terms. ▪ Climate change is likely to affect the rainfall regime in Ireland which in turn will impact on the supply and infrastructure. Higher fluctuations could mean periods of excess water (flooding) of shortage (drought). The infrastructure itself is less vulnerable to damage.

1 See www.spiritofireland.org

Availability change	▪ IPCC confirms that hydropower is the energy source most likely to be impacted by climate change because it is sensitive to the amount, timing, and geographical pattern of precipitation as well as temperature (rain or snow, timing of melting). ▪ Although there is an increase in precipitation during the winter and a decrease in the summer these seasonol patterns do not directly impact on increased output in winter or lower in summer. This is primarily because the current hydro technology doesn't take advantage of the increased flow in water.

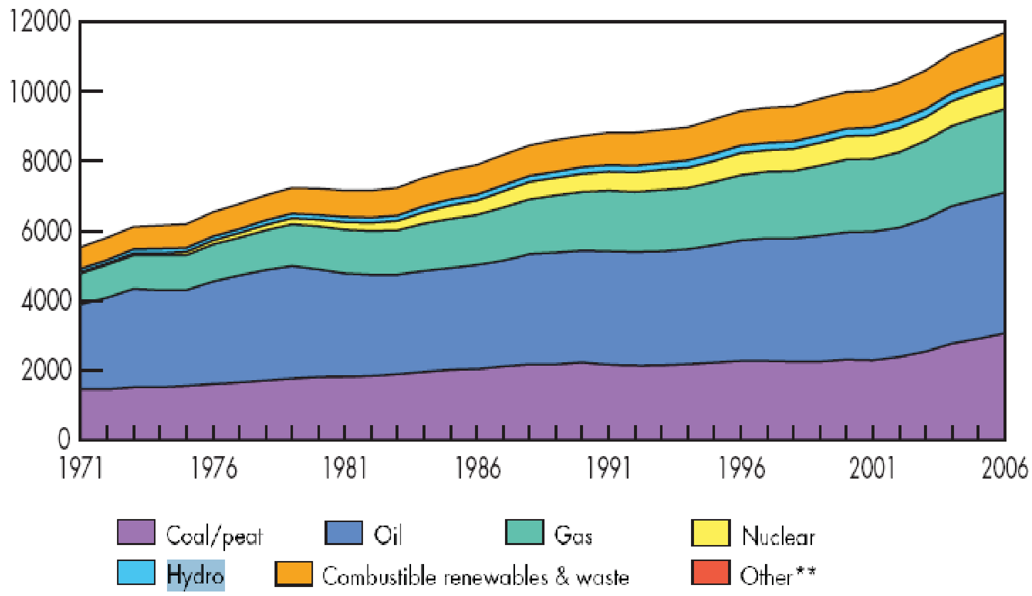
10.1 Hydropower: the basics

Hydropower is the world's number one source of renewable electricity and supplies 20 per cent of the world's electricity. Figure 10.1 shows its growth from 1.8 per cent of the world's energy source in 1973 to 2.2 per cent in 2006 (IEA, 2008[2]). There are 25 countries that depend on more than 90 per cent of their electricity supply from hydro and 12 are 100 per cent reliant. Canada, China and the USA are the three largest generators of hydro electricity.

Hydropower uses the power of flowing or falling water in order to produce electric power. It is the only renewable technology that can be used to store quantities of energy using reservoir storage and pumped storage schemes. It does this by moving water from a low elevation to a higher elevation during periods of low demand (when there is excess electricity production), and then releasing the water when more electricity is needed than the base load can generate. Run-of- the river schemes have no storage capabilities and use the natural ebb and flow of the water to produce electricity.

Although the size of hydroelectric facilities can vary greatly from micro (1 MW) to small (10 – 30 MW), to medium to mega projects (the Three Gorges Dam in China will produce 22,500 MW), in the Irish context the most relevant are the small and medium sized projects.

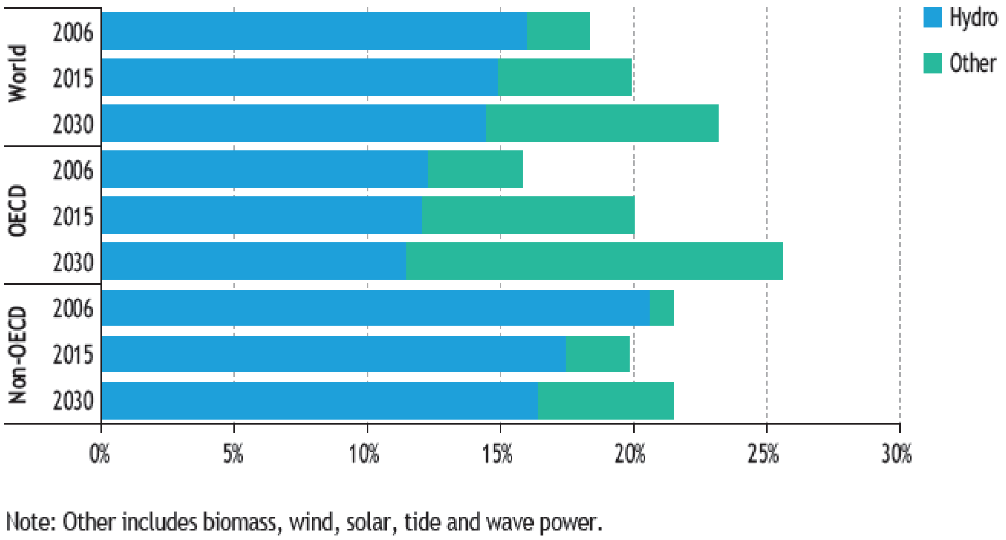
Figure 10.1: Evolution of world energy resources from 1971 to 2006



Source: IEA, 2008 (IEA world statistics)

2 IEA, 2008, *Energy Technology Perspectives*

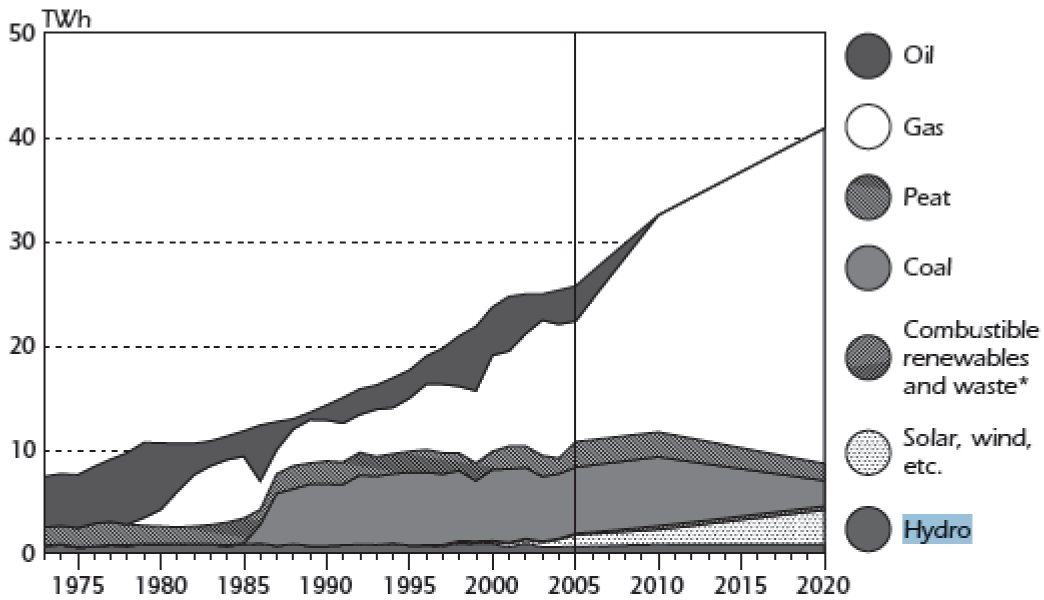
Figure 10.2: Share of total electricity generation by renewables



Source: IEA, 2008 (World Energy Outlook)

Hydropower remains the largest source of renewable energy for electricity and doubles in absolute terms over the period from 2006-2030.However, other renewables are predicted to fast track and the proportion of hydropower is set to decrease over the specified time period, see Figure 10.3 below.

Figure 10.3: Electricity generation by source 1973 to 1920



Source: IEA, 2007

10.2 Hydropower as an energy source

Hydropower is a renewable resource and there are no signs that there will be any decrease in its availability in the long run. The fuel for hydropower is water and is free. Hence there is no fuel cost. However, suitable sites for hydropower in the future may be an issue.

There is no import dependence on the fuel as hydroelectricity uses an indigenous water resource for the production of electricity.

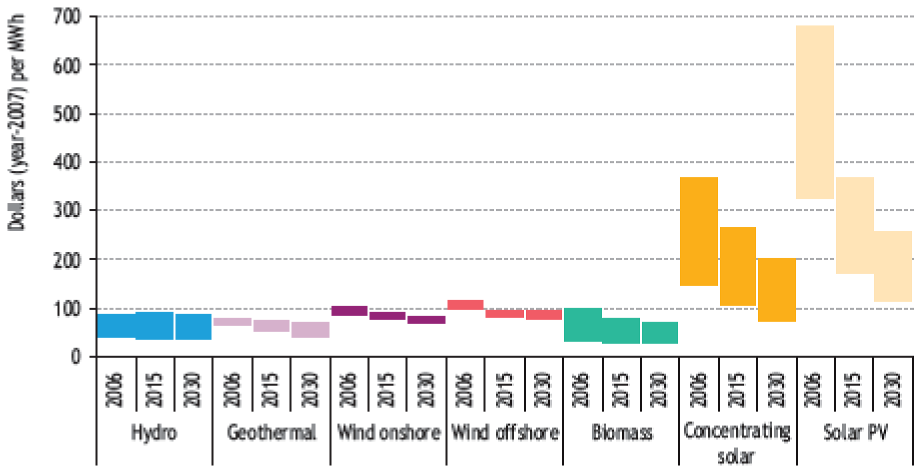
10.3 Hydropower in the energy system

10.3.1 Delivered energy cost

Hydroelectricity is characterized by a major investment cost, a low operating cost due to a high amount of automation, and no fuel cost except with pumped storage facility. The development of a new hydroelectric facility is capital intensive and construction typically takes place over a long period of time. However, since the lifetime of hydro plants tend to be quite long the depreciation costs are very low or nil which means that the delivery costs tend toward the operating costs of the plant. In the case of Ireland, there are no new sites for medium hydro facilities which mean that the least-cost option going into the future will be to modernize the existing plants in order to add capacity. Equipment with improved performance can be retrofitted to accommodate market demands for more flexible peaking modes of operation (WEC, 2007[3]).

Hydroelectricity is particularly a good source of renewable energy as it is competitive with traditional mid peak load and peak load plants which have higher costs than base load plants (IEA, 2008, WEO[4]). According to the MIT (2007) study hydro appears to cost between 2-8 €-cent/kWh and this does not appear to decrease over time. Figure 10.4 concurs with this finding. Small hydro costs between 4 -10 €-cent/kWh. This is also not expected to change over time. Table 10.1 below, illustrates the costs of hydropower as a delivered energy cost over the three time periods, 2010, 2020 and 2030.

Figure 10.4: Costs of renewable energy



Source: IEA, 2008 (WEO)

3 World Energy Council (WEC), 2007, *Performance of Generating Plant: Managing the Changes*, Published by WEC

4 IEA, 2008, *Energy Technology Perspectives*, World Energy Outlook

Table 10.1: Costs of hydropower energy (delivered cost)

	2010	2020	2030
Small scale hydro	4-10	4-10	4-10
Medium scale hydro	2- 8 (MIT)	2- 8 (MIT)	2 - 8 (MIT)

Source: MIT (2007)

10.3.2: Hydropower – conversion technologies

Hydropower is an established technology. In the future, as many of the large-scale opportunities are exhausted there will be the need to concentrate on smaller-scale schemes, which is particularly the case in Ireland. The technology will need to become more efficient to maximise this diminishing resource and to cope with lower flows and higher seasonal and other fluctuations. Smaller-scale schemes are also associated with rivers and streams with limited scope for storage, which also has to be addressed. The IEA expects that research, development and demonstration will continue in the area of hydropower technology.

10.3.3: Policy and regulation

There are no policy or regulatory barriers to hydro power (the barriers tend to be due to the technological potential). However, the planning process in Ireland could potentially be a barrier to new hydro developments,especially as local governments are given authority to repeal applications (although these can be appealed). Appropriate financing models are needed for the hydropower sector, as is finding the optimum roles for the public and private sectors[5] .

Apart from the EU RES target the Renewable Energy Feed in Tariff (REFIT) is the main incentive for the uptake of renewables in Ireland. The scheme is essentially a banded feed-in tariff that replaced a competitive tendering approach in May 2006. The original system was replaced as it was realized that successful bidders were winning because they bid at prices too low to actually operate at a profit. Given that ESB still has the market monopoly over the production of electricity it was seen as unlikely that green certificate schemes such as the renewables obligation in the UK would have many benefits and would not further the government’s aim to increase the number of small, independent wind farm operators.

The following stable and consumer price-indexed feed-in tariffs are offered to developments banded by type of technology:

- Large-scale wind category – €57/MWh
- Small-scale wind category – €59/MWh
- Hydro – €72/MWh

5 World Energy Council (WEC), 2007, *Performance of Generating Plant: Managing the Changes*, Published by WEC

- Biomass landfill gas – €70/MWh
- Other biomass – €72/MWh

There are some limitations to eligibility of applicants to the subsidy and these are as follows:

- Capacity limitation to 400 MW (later raised to 620 MW) total additional renewables capacity;
- Time limitation to 15 years per contract;
- Time limitation for access to the REFIT of 2009 and the associated support cannot continue beyond 2024 in any contract;
- Developers have to negotiate supply contracts independently;
- Qualifying plants must be new in that it must not be built or under construction on 30 April 2005;
- The project must have received full planning permission unless the applicant can prove that planning permission is not required;
- The generator must have received a connection offer which must not have expired; and
- The generator must demonstrate that title has been obtained to the relevant site for a period equal or longer than the duration of the power purchase agreement (PPA).

The supplier must offer a fixed price for all electricity produced irrespective of the prevailing price of electricity for the duration of the contract. As the transfer of revenue risk is made from the developer to the supplier the project tends to be a lot more attractive as it minimizes the debt servicing cost for project developers. This is a large benefit as debt servicing can often be as high as 66 per cent of annualized costs. The supplier is compensated for the average difference between the cost of purchasing at €57/MWh (the large-scale wind price) and the estimated costs it would incur purchasing and selling excess dispatchable power in the current top-up and spill market, a precursor to the planned pool market. The REFIT programme calculates this difference as the cost of balancing undispatchable power at €8.5/MWh payable to participating suppliers. In addition, suppliers contracting with the higher cost technologies are compensated for the additional cost incurred above the large-scale wind price, i.e. €59 - €57/MWh for small-scale wind projects, €70 - €57/MWh for landfill gas projects, and €72 to €57/MWh for small hydro and other biomass. (IEA, 2007)

10.3.4: Market context in Ireland

Currently in Ireland there are 527 MW of hydro electricity installed[6] accounting for 7 per cent of installed capacity. Table 10.2 itemises the largest schemes. As Ireland has reached its Hydro capacity, new developments in this area will typically be small hydro projects (where there is some unexploited potential) and retrofits to existing hydro plants (CER, 2008). Small-scale hydro is a useful way of providing power to houses, workshops or villages that need an independent supply. The electricity generated can potentially be supplied to the local community. Surplus electricity can be sold to the national grid. There are studies that show

6 CER, 2008

that there is between 32-76 MW of small scale hydro capacity available in primarily mountainous areas[7].

Table 10.2 Overview of current Irish hydro capacity

Hydro station	Capacity (MW)	
Turlough Hill	292	Located in the South East, this is a pumped storage facility
Liffey	38	Located near the South East, the Liffey scheme was an example of the co-operation of engineers for a dual purpose. In creating the water storage for the power stations at Poulaphouca, Golden Falls and Leixlip, the vital need for increased water supplies to Dublin was met by the 5,600 acre reservoir.
Ardnacrusha	86	Originally called The Shannon Scheme, the first hydro electric scheme with custom canal (centrally located).
Erne	65	
Clady	4	
Lee	27	

Source: UKTI, 2007

10.3.5: Supply chain and markets

Whilst there is perceived vulnerability of infrastructure in terms of reservoir leaks and there are virtually no reported incidents, hydro is considered highly resilient.

There is little volatility in the market for hydro fuel as it is dependant on a natural resource available in Ireland.

The infrastructure for hydroelectricity is robust and scores well on both complexity and fragility.

10.3.6: Energy availability and intermittency

While wind and solar are intermittent sources of energy, hydro can provide security and quality of supply to the system and provide services during peak demand times. This is especially the case with storage hydro and pumped storage which can store reservoirs of

7 Cork Country Council, 2005

water for use at times of peak demand (WEC, 2007[8]). However, even pumped storage hydro is not available 100 per cent of the time as there are times when the water must be pumped for use later and therefore the plant cannot be used to produce electricity. Furthermore, run of the river schemes are highly dependant on unpredictable water flows. Options for increased use of pumped storage are currently being examined by a number of parties in Ireland[9].

10.3.7: Environmental impacts

The hydroelectric fuel cycle is very simple compared to a fossil fuel cycle and as such the impacts of construction and dismantling play a bigger part on the environment then the actual running of the plant. The most important feature of the hydro fuel cycle is its site specificity. Since damages are mostly produced on the local environment, its conditions determine the results. Therefore, these results are very difficult to extrapolate to other sites, and large differences may be produced depending on the sites and technologies chosen.

Examples of environmental impacts include the impacts of the river ecosystems because of the changes in river flow, and the artificial barriers created. These impacts include changes in water quality, in hydrological systems, and in the flora and fauna of the region. Many fish species, such as salmon, depend on steady flows to flush them down river early in their life and guide them upstream years later to spawn. Slow reservoir pools disorient migrating fish and significantly increase the duration of their migration. In addition, bacteria present in decaying vegetation can also change mercury, present in rocks underlying a reservoir, into a form that is soluble in water. The mercury accumulates in the bodies of fish and poses a health hazard to those who depend on these fish for food. (IEA, 2000)

An important aspect also is the loss of amenity because of the landscape changes, and the variations in recreational activities. It is assumed that other impacts such as population resettlement, or land loss, are usually internalised, and are not being assessed.

The ExternE implementation[10] assessed both run of the river and reservoirs hydro facilities. The first one does not change severely river flow (therefore its effect on the environment is rather benign), while the second needs the flooding of large spaces to provide enough volume of water. Impacts of pumped storage hydro facilities are much larger in the case of reservoirs, as valleys may be flooded with the reservoirs, thus affecting a large extension of terrestrial ecosystems.

It has to be noted that not only negative impacts arise from the hydro fuel cycle. For example, run-of-the-river plants provide flood prevention, and regulation of river transport. Reservoirs provide water for irrigation and domestic use on a regulated way. Upstream impacts, however, are usually negative. Those considered are the pollutant emissions due to material manufacturing and power plant construction.

As mentioned before, most of the damages are ecological effects due to the plant operation. The impacts of construction are mostly due to pollutant emissions. The average of the ExternE studies sets the external cost of hydro between 0.04 – 6 €-cent/kWh. A study by MIT (2007) reports the EU range of costs between 0 and 1 €-cent/kWh. The value used in the

8 World Energy Council (WEC), 2007, *Performance of Generating Plant: Managing the Changes*, Published by WEC

9 See www.spiritofireland.org

10 ExternE, 1998, *Externalitios of Energy*, Eurpoean Commission, DG X II

index for all time periods is 1.5 €-cent/kWh, which is an average of all the lower and upper bounds reported in the reviewed literature.

Table 10.3: External costs for EU electricity production (range: €-cent/kWh)

Country	Coal & lignite	Peat	Oil	Gas	Nuclear	Biomass	Hydro	PV	Wind
Austria				1-3		2-3	0.1		
Belgium	4-15			1-2	0.5				
Germany	3-6		5-8	1-2	0.2	3		0.6	0.05
Denmark	4-7			2-3		1			0.1
Spain	5-8			1-2		3-5			0.2
Finland	2-4	2-5				1			
France	7-10		8-11	2-4	0.3	1	1		
Greece	5-8		3-5	1		0-0.8	1		0.25
Ireland	6-8	3-4							
Italy			3-6	2-3			0.3		
Netherlands	3-4			1-2	0.7	0.5			
Norway				1-2		0.2	0.2		0-0.25
Portugal	4-7			1-2		1-2	0.03		
Sweden	2-4					0.3	0-0.7		
United Kingdom	4-7		3-5	1-2	0.25	1			0.15
EU range	2-15	2-5	3-11	1-4	0.2-0.7	0-5	0-1	0.6	0-0.25
Median Lower Bound	4	2.5	3	1	0.3	1	0.2	0.6	0.125

Source: MIT, 2007(Renewable Energy Strategies)

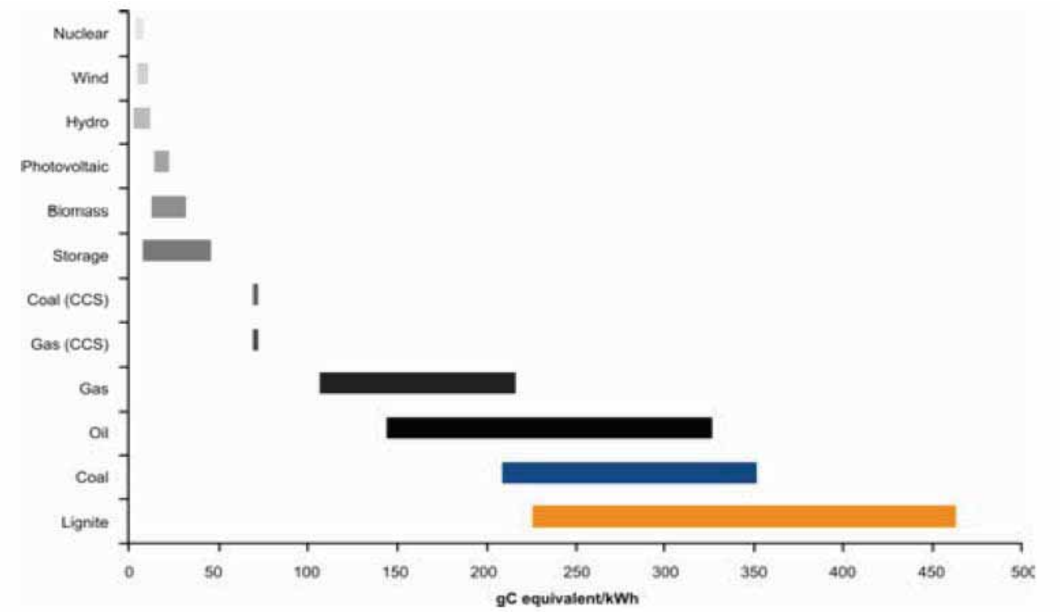
10.4 Hydropower and climate change

10.4.1: Carbon content and lifecycle carbon footprint

Hydro does not have any carbon content by its very nature.

In terms of climate change, hydropower tends to have a very low greenhouse gas footprint. Storage schemes have a higher footprint, (10-30g CO_2eq/kWh), than run-of-river schemes as they require large amounts of raw materials (steel and concrete) to construct the dam. Furthermore, accumulated sediments in reservoirs contain noticeable levels of carbon, which may be released to the atmosphere upon decommissioning of the dam. The carbon footprint for run-of-river schemes is reported to be less than 5 gCO_2eq/kWh (POST, 2006) while other sources report a value of 4 gCO_2/kWh (WEC, 2007). Figure 10.5 shows the WEC's estimate of hydroelectric power's footprint in comparison with other technologies.

Figure 10.5 Total lifecycle GHG emissions of various fuels



Source: WEC, 2007

10.4.2: Supply and infrastructure vulnerability

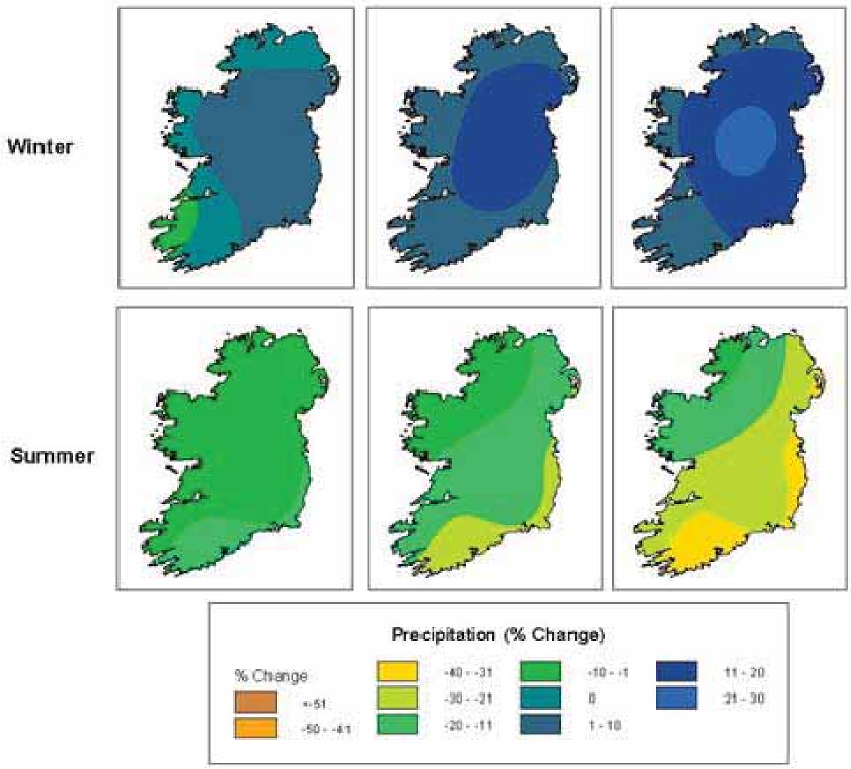
Climate change is likely to affect the rainfall regime in Ireland which in turn will impact on the supply and infrastructure. Higher fluctuations could mean periods of excess water (flooding) of shortage (drought). The infrastructure itself is less vulnerable to damage.

10.4.3: Availability change of the resource

The IPCC confirms that hydropower is the energy source most likely to be impacted by climate change because it is sensitive to the amount, timing, and geographical pattern of precipitation as well as temperature (rain or snow, timing of melting). As a general rule, if there is a reduction in streamflow then hydropower will be impacted negatively, however, if there is greater streamflow then hydroelectric production should be helped. There are a number of caveats to this claim and these are discussed later in this section.

In Ireland there will be increasing precipitation during winter, which is confirmed by the EPA who report that the most significant changes in precipitation will occur in June and December. They report that there is potential for increases in precipitation in December ranging between 10 and 25 per cent in the south-east and north-west. In June values show a decrease of about 10 per cent compared with the current climate and will be concentrated in the southern half of the country, see Figure 10.6.

Figure 10.6: Map showing the increase in precipitation for summer and winter



Source: EPA

This means that there will be an increased rate of water flow in the winter which could potentially mean a greater resource. However, an earlier review by the IPCC questions whether the electric system can actually take advantage of these increased flow rates during winter (IPCC, 2003). Hydroelectric projects generally are designed for a specific river flow regime, including a margin of safety. Projected climate changes are expected to change flow regimes-perhaps outside these safety margins in some instances. Furthermore, the increase in river flows in the winter are counterbalanced by the decrease in precipitation during the summers, which could mean that there is a net decrease in availability of hydro electric power available over both seasons. The magnitude of this decrease is subject to debate.

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11 IEA, 2007, *Energy Policies of IEA Countries: Ireland*

The Irish Energy Tetralemma

Fuel Report 11: Nuclear

August 2010

Forfás

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Executive Summary

Competitiveness

Fuel Cost	▪ The cost structure of nuclear generation is closer to wind or marine sources in that it enjoys very low marginal costs, although initial capital costs are high. ▪ Typically around half of the marginal costs are dependent on market conditions for uranium whereas the remainder of the costs are based on the costs of plant operations. ▪ World uranium resources are capable of delivering uranium to 2030 at prices that are broadly similar to today's market prices of US$39.62 per lb U_3O_8 (2006 money values), subject to market efficiency, with finished fuel costs estimated to be €1.29 per GJ (2006 money values) in all three time periods. ▪ Ireland has no relevant uranium resources or fuel cycle facilities on its territory that could support any part of the supply chain in nuclear fuel.
Delivered energy cost	▪ Delivered costs are significantly higher than fuel costs because of the addition of capital amortisation and charges for nuclear decommissioning and spent fuel management costs. ▪ The full cost of delivered nuclear electricity (including the cost of all nuclear liabilities) is expected to be €9.61 per GJ (2006 money values) in 2020 and 2030. ▪ If a nuclear power station were to be constructed in Ireland, it is likely that the cost of delivered energy would be measurably more than the above estimate because a single nuclear power station would still require similar levels of support as a large fleet. This would include the costs of engineering and safety support capabilities, regulatory oversight, additional nuclear infrastructure and a suitable network.
Policy & Regulation	▪ The nuclear fuel markets are extremely well established and regulated internationally. ▪ Ireland does not have the regulatory capacity at present to support an operational nuclear power station. ▪ Nuclear is still likely to be deeply unpopular in Ireland and considerable efforts would be required to change negative perceptions and planning permission would be extremely difficult to obtain. ▪ Nuclear therefore faces very high regulatory barriers.
Market context in Ireland	▪ The electricity pool in Ireland has no obvious mechanisms to discriminate for or against nuclear electricity.

Security of supply

Import dependence	▪ All nuclear fuel for Ireland would have to be imported unless the country decided to invest in nuclear fuel cycle facilities. With such a small potential nuclear programme, it is highly unlikely that such investment would be viable. ▪ Key components for reactor construction would most probably be imported.
Fuel place of origin	▪ Uranium is available from every continent and dozens of countries around the world. ▪ There are only a handful of facilities to process uranium into reactor fuel around the world, although these are geographically diverse and most of these are located in stable countries. ▪ Geographical diversity is unlikely to change significantly over the relevant periods.
Supply and Infrastructure resilience	▪ Places of extraction, manufacture and processing are extremely safe and secure. ▪ Transport is the weakest link in the supply chain but has been historically reliable. ▪ Uranics work in progress and reactor cores reactivity provide significant buffer time in the event of transport delay.
Market volatility	▪ The uranium market has functioned well for many decades and is well established. ▪ The necessary uranic materials can be traded at different stages in the process allowing several competitive market options.
Energy availability and intermittency	▪ There are no identifiable factors that are expected to impinge on viability over the period.

Sustainability

Fuel longevity	▪ Although all categories of uranium resource suggest forward cover of over 200 years (not taking account of the measures that could extend this considerable such as reprocessing, choice of tails assay in the enrichment process, increased burn-up etc), Reasonably Assured Resources in the lowest cost band will last approximately to 2030.
Environmental impact	▪ Nuclear waste is created in very small volumes compared with fossil wastes and if properly managed poses only low risks of environmental pollution. ▪ Nuclear fuel does not emit significant particulate pollution, it is highly immobile, unlike chemically hazardous fuels, and its

	hazardous radioactive characteristics are time limited by a half-life. ▪ Mortality rates from nuclear power are extremely low. ▪ The perception of risk from nuclear is that a serious incident could be so catastrophic as to outweigh all the safety benefits that have accrued to date.

Climate change

Carbon content	▪ Nuclear fuel creates no significant carbon emissions at the point of generation.
Lifecycle carbon footprint	▪ The life cycle global warming impact of all embodied carbon and associated greenhouse gas emissions can be engineered to be very low indeed and similar to those of wind. ▪ An average of a wide range of studies would suggest that 66 gCO_2eq/kWh would be an average lifecycle carbon footprint for nuclear.
Supply and infrastructure vulnerability	▪ The supply chain for nuclear fuel is unlikely to be affected by climate change in a way that could not be managed through simple adaptive measures. ▪ Far more relevant is the site chosen for a nuclear power station because of the very significant sea level rise, peak and average temperature rises, extreme weather occurrences, storm surges and other climate effects that are now almost certain to result from anthropogenic climate change damage to date.
Availability change	▪ Nuclear fuel will not be affected by climate change.

11.1: Nuclear: the basics

Nuclear power is a proven and mature technology used to generate commercial electricity in over 40 countries. As of October 2008, there were 439 operational nuclear reactors which generated 2,608 TWh of electricity in 2007. A further 36 reactors with a capacity of 29,848 MWe are under construction, 99 reactors with a capacity of 108,675 MWe are planned or ordered and 232 reactors with a capacity of 211,575 MWe are proposed. A full list is presented in Appendix A.

Electricity is generated from nuclear power in the same way as many conventional forms of fossil fuel generation. Instead of fossil fuel, uranium is used as fuel to produce heat through the process of uranium fission.

Significant additional considerations arise in respect of the way the nuclear fuel, waste and decommissioning are managed in order to protect both people and the environment from radioactive contamination and irradiation.

Uranium Background

Uranium was probably formed in supernovae some 2 billion years before the Earth formed. It is present at the centre of the Earth and the heat it generates there causes convection and continental drift. Naturally occurring uranium comprises two main isotopes of interest. These are U^{238} (99.284 per cent by weight, half life 4.5×10^9 years) and U^{235} (0.711 per cent by weight, half life 7.10×10^8 years). Heat for energy production is derived from the fissile[1] component, U^{235}. Uranium normally exists in nature in its oxidised form of triuranium octoxide, or U_3O_8 (NATO, 2005[2]). Uranium is abundant in the Earth's crust being as common as zinc and is distributed in varying concentrations indicatively as in Table 11.1.

Table 11.1: Concentrations of Uranium in the earth's crust

Source	Concentration in parts per million Uranium
High grade ore body - 2 % U or higher	20,000
Low grade ore body - 0.1 % U	1,000
Granite	4
Sedimentary rock	2
Average in Earth's continental crust	2.8
Seawater	0.003

Source: WNA Uranium Supply (2008)

1 In nuclear engineering, a fissile material is one that is capable of sustaining a chain reaction of nuclear fission

2 NATO, 2005, Armed Forces Radiobiology Research Institute, Status of Health Concerns about Military Use of Depleted Uranium

Although uranium can be extracted from seawater, it is far more economic to extract supplies from the Earth's crust where it accumulates in localised areas of high concentration. The principle methods of extraction include conventional, underground and open pit mining as for coal, in situ leach, and as a by-product of other mining processes such as copper or gold mining. In Situ Leach (ISL) is a mining process whereby the ore body containing the uranium is not removed from the ground, but instead involves injecting a leaching agent, such as fortified water, into the ore body, recovering uranium from the pregnant agent. (WNA ISL, 2008[3]). Table 11.2 shows the relative percentages of uranium mined using the alternative methods.

Table 11.2: Contribution of mining methods to world uranium supply

Mining Method	Percentage contribution %
conventional underground & open pit	62
in situ leach (ISL)	29
by-product	10

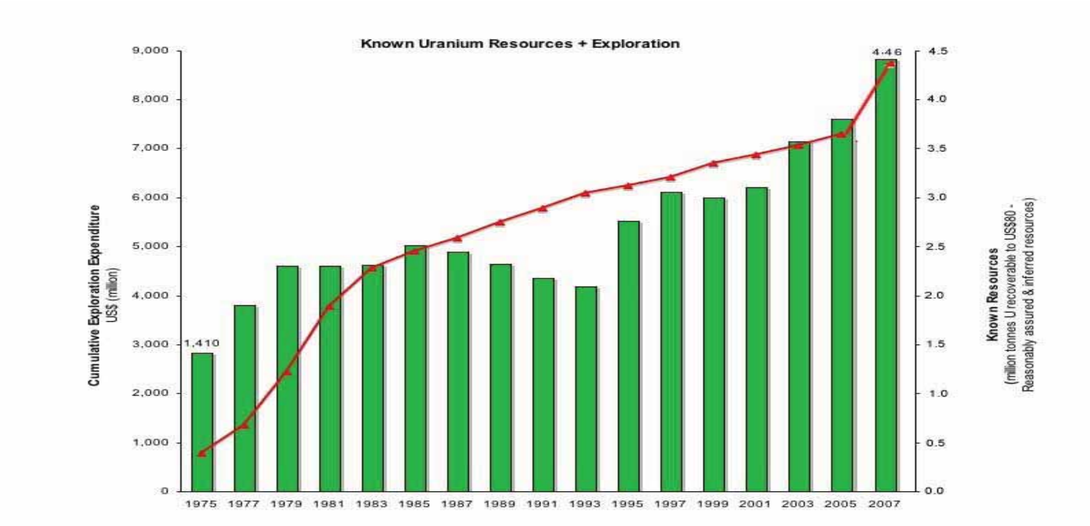
Source: WNA Uranium Mining (2006)

An ore body is defined as the occurrence of uranium mineralisation that is economically recoverable. The economics of extracting uranium depend on a number of factors including the costs of the mining method used and the concentration of uranium being extracted. The concentration of uranium in an ore body is usually expressed as weight per cent of uranium in the ore being mined, and is referred to as the ore grade.

Exploration expenditure is stimulated by high uranium prices. Throughout its history, cumulative recoverable uranium resources have expanded in line with cumulative uranium exploration expenditure as shown in Figure 11.1.

3 World Nuclear Association (WNA), In Situ Leach (ISL), 2008, *Mining of Uranium*, March 2008

Figure 11.1: Recoverable uranium resources and exploration expenditure



Source: WNA Uranium Supply (2008)

Generally, as ore grades reduce, it becomes more expensive to mine using the same method. Nevertheless,ore grade alone is by no means a reflection of whether uranium contained within a particular ore body is economically recoverable. This is because other factors, including technological development, do not remain static and respond to changing conditions. For this reason, it can be possible for the Rossing uranium mine, with average ore grades of 0.035 % w/t U to compete in the same market as the future Cigar Lake mine, with average ore grades of 20.7 % w/t U[4], close to three orders of magnitude higher.

The Nuclear Fuel Cycle

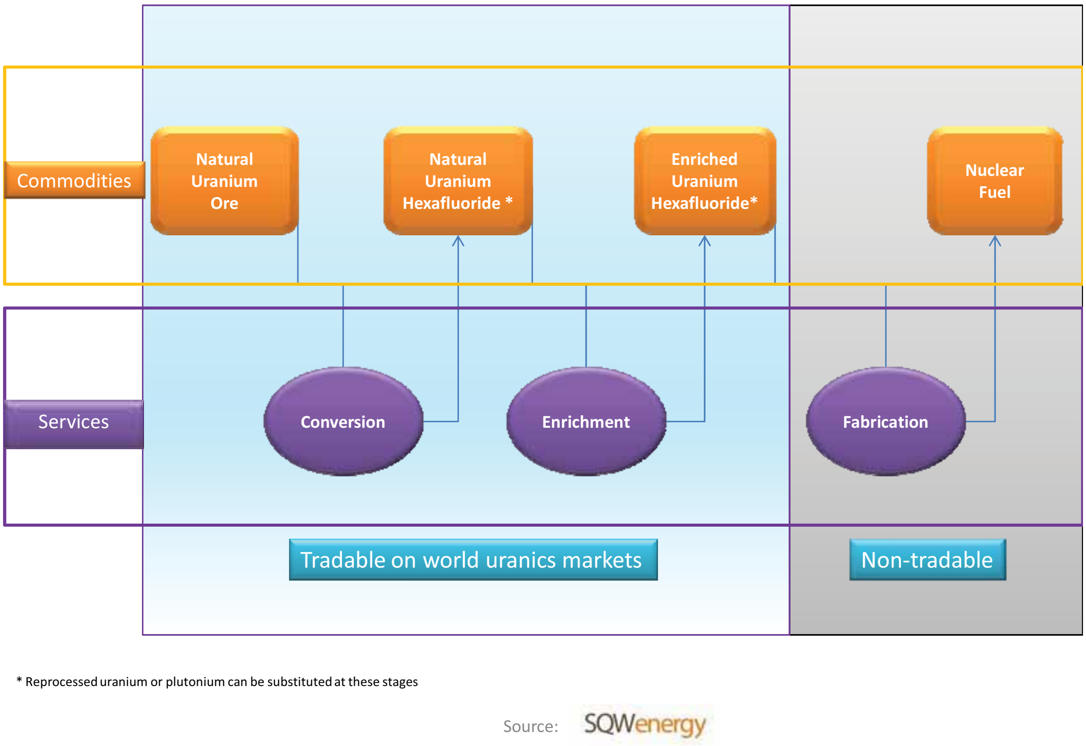
Nuclear fuel in the form of mined uranium as U_3O_8 cannot be used directly in power reactors. It must first be processed and packaged in various ways so that it is delivered to the power station in a form that the specific reactor can accept. The set of processes from uranium mining through to fuel delivery to power stations and loading into a nuclear reactor is known as the "Front End Fuel Cycle".

When fuel is removed from a reactor, it must be cooled, stored and safely disposed of. The set of processes from removal from the reactor through to final disposal is known as the "Back End Fuel Cycle". The descriptions in the sections below are based in part on information provided by the World Nuclear Association[5].

4 Cameco Summary, 2008, Cameco Summary on Cameco Website, 2008

5 World Nuclear Association, 2008, *Nuclear Fuel Cycle*, September 2008

Figure 11.2: Front End Fuel Cycle



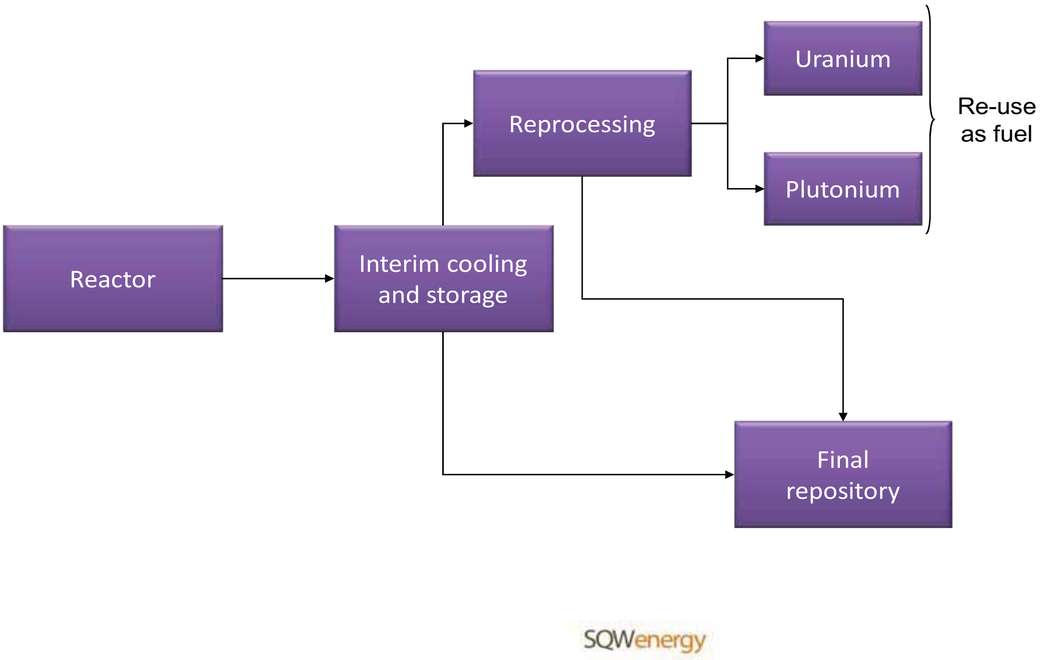
Source: SQW Energy & WNA Nuclear Fuel Cycle, 2008

Figure 11.2 above shows the Front End Fuel Cycle. Uranium is extracted from ore bodies in the Earth's crust. At this stage, the uranium is in the form of U_3O_8 and it is still mixed with inert ore which together is known as uranium ore concentrates (which contains typically 80% U_3O_8). This form is also known as "yellowcake". The yellowcake is milled and through a process of leaching, the U_3O_8 is separated from the wastes. The U_3O_8 is then packed into drums, such as oil drums, for shipping. At this stage, the proportion of the fissile U^{235} isotope is the naturally occurring 0.711 w/t % and the contained uranium is known as "natural uranium". Throughout this process, the contained U_3O_8 may be bought and sold.

The next stage of the process is known as "Conversion", the purpose of which is to convert the U_3O_8 into a form that is acceptable for the enrichment process. Most power reactors require that the proportion of U^{235} isotope is increased from the naturally occurring level of 0.711 % to typically between 3.5 % and 5 % in a process known as "Enrichment". The output of the conversion process is natural uranium hexafluoride ($UF_{6\ natural}$), which exists as a gas at relatively low temperatures. Both conversion services and the product of conversion, $UF_{6\ natural}$, are separately traded.

The enrichment process receives $UF_{6\ natural}$ and produces two streams of output. The first is a blend of U^{238} and U^{235} where U^{235} represents between 3.5 % and 5 % w/t of the total, and a second stream, known as Uranium Enrichment Tails, which is depleted in U^{235} such that it may represent only 0.2 % w/t of the stream. Enriched uranium is then processed into fuel assemblies for use in a reactor.

Figure 11.3: Back End Fuel Cycle



Source: SQW Energy

Figure 11.3 above shows the Back End Fuel Cycle and the pathways for the fuel once it has been used in the reactor and discharged. Following initial cooling, usually on site, the fuel may be stored for a period and then disposed of permanently. Most permanent disposal solutions envisage burial in a deep underground repository between several hundred metres and up to two kilometres deep. Between storage and disposal, another option is to recover fissile materials from the spent fuel that can be used as new fuel. These products are unused uranium and plutonium that is created as a result of the process of nuclear fission. This process is called “reprocessing”.

Regulatory context

Any future Irish nuclear development will realistically only take place within the overall context of the well established and highly effective framework of international law and regulation as well as the Irish legal system. This section describes this context and its relevance to any future nuclear development in Ireland.

Nuclear development is highly controlled and regulated on an international basis by the International Atomic Energy Agency (IAEA). As an independent international organization related to the United Nations system, the IAEA’s relationship with the UN is regulated by special agreement. The IAEA reports annually to the UN General Assembly and, when appropriate, to the Security Council regarding non-compliance by States with their nuclear safeguards obligations and matters of international peace and security.

AEA started life in 1957 under the name “Atoms for Peace” as an arm of the United Nations. The purpose of the IAEA is defined in its Statutes and may be summarised under the following three headings:

- to promote nuclear safeguards and verification;
- to promote safety and security; and
- to promote science and technology

The Euratom Atomic Energy Community (the Euratom Treaty) was founded in 1957 and acceded to by Member States of the European Union who have since joined the Community. The purposes of the Euratom Treaty were to create the conditions necessary for the development of a powerful nuclear industry, to create the conditions of safety necessary to eliminate hazards to the life and health of the public and to cooperate with international organisations concerned with the peaceful development of atomic energy. Euratom acts for the IAEA in administering nuclear safeguards in the Community and also aims to ensure security of supply of nuclear fuel through the Euratom Supply Agency, which is in effect the regulator of commercial trade of uranium products and services in the Community.

The Irish Electricity Act 1999 (Section 18 Prohibition, 1999) specifically prohibits the Regulator to licence the development of a nuclear station for the purposes of electricity generation and supply, but empowers the Regulator to licence other forms of electricity generation[6]. Paramount to any nuclear development in Ireland would be the establishment of an internal nuclear regulator with the resources and experience to operate on an industrial scale. Such institutions are typically emanations of state legislation and need the technical capacity to evaluate complex nuclear safety cases on an ongoing basis.

6 The section does not appear to constitute a generic ban on nuclear installations – for example, it is not evident that a nuclear power station designed solely for the generation and supply of heat would be prohibited by this particular regulation

11.2: Nuclear fuel as a commodity

Table 11.3 below shows the OECD Nuclear Energy Agency view of uranium resources worldwide as of 2006 and as published periodically in the Agency's Red Book OECD (2006).

Table 11.3: Uranium Resources

<table>
<tr><th colspan="2">Resource category</th><th>Cost range ($1kgU)</th><th colspan="2">Resource (kt)</th></tr>
<tr><th colspan="2"></th><th></th><th></th><th>Cumulative Totals</th></tr>
<tr><td colspan="2" rowspan="3">Reasonably Assured Resources (RAR)</td><td><40 $/kgU</td><td>1,947</td><td>1,947</td></tr>
<tr><td>40-80 $/kgU</td><td>696</td><td>2,643</td></tr>
<tr><td>80-130 $/kgU</td><td>654</td><td>3,297</td></tr>
<tr><td colspan="2" rowspan="3">Inferred resources (IR)</td><td><40 $/kgU</td><td>799</td><td>4,096</td></tr>
<tr><td>40-80 $/kgU</td><td>362</td><td>4,458</td></tr>
<tr><td>80-130 $/kgU</td><td>285</td><td>4,743</td></tr>
<tr><td rowspan="4">Undiscovered resources</td><td rowspan="2">Prognosticated</td><td><80 $/kgU</td><td>1,700</td><td>6,443</td></tr>
<tr><td>80-130 $/kgU</td><td>819</td><td>7,262</td></tr>
<tr><td rowspan="2">Speculative</td><td><130 $/kgU</td><td>4,557</td><td>11,819</td></tr>
<tr><td>unassigned</td><td>2,979</td><td>14,798</td></tr>
</table>

Source: NEA, 2006

Currently, the annual demand for uranium is around 65,000 tonnes. Based on the above table showing the forward cover available from the highest category of uranium sources, (the Reasonably Assured Resources), uranium should be available at a cost of less than US$40/kg U_3O_8 until 2038.

Table 11.4: Uranium resource forward cover worldwide for demand of 65,000 tU per annum

Resource Category	Tonnes uranium	Cumulative Totals	Cumulative Years' Cover
RAR<\$40 / lb U_3O_8	1,947,000	1,947,000	30
RAR<\$40 - 80 / lb U_3O_8	696,000	2,643,000	41
RAR<\$80 - 130 / lb U_3O_8	654,000	3,297,000	51

Source: OECD, 2006

As shown in Table 11.5 below, if inferred resources are included, the cumulative years' cover has improved considerably.

Table 11.5: Uranium resource forward cover worldwide for demand of 65,000 tU per annum (including inferred resources)

Resource Category	Tonnes uranium	Cumulative Totals	Cumulative Years' Cover
RAR + IR <\$40 / lb U_3O_8	2,746,000	2,746,000	42
RAR + IR<\$40 - 80 / lb U_3O_8	1,058,000	3,804,000	59
RAR + IR<\$80 - 130 / lb U_3O_8	939,000	4,743,000	73

Source: OECD (2006)

Subsequently if all the uranium reserves were accounted for by OECD using present rates of consumption there would be nearly 220 years' cumulative forward cover, see Table 11.6

Table 11.6: Sustainability figures for uranium for 2010, 2020, 2030

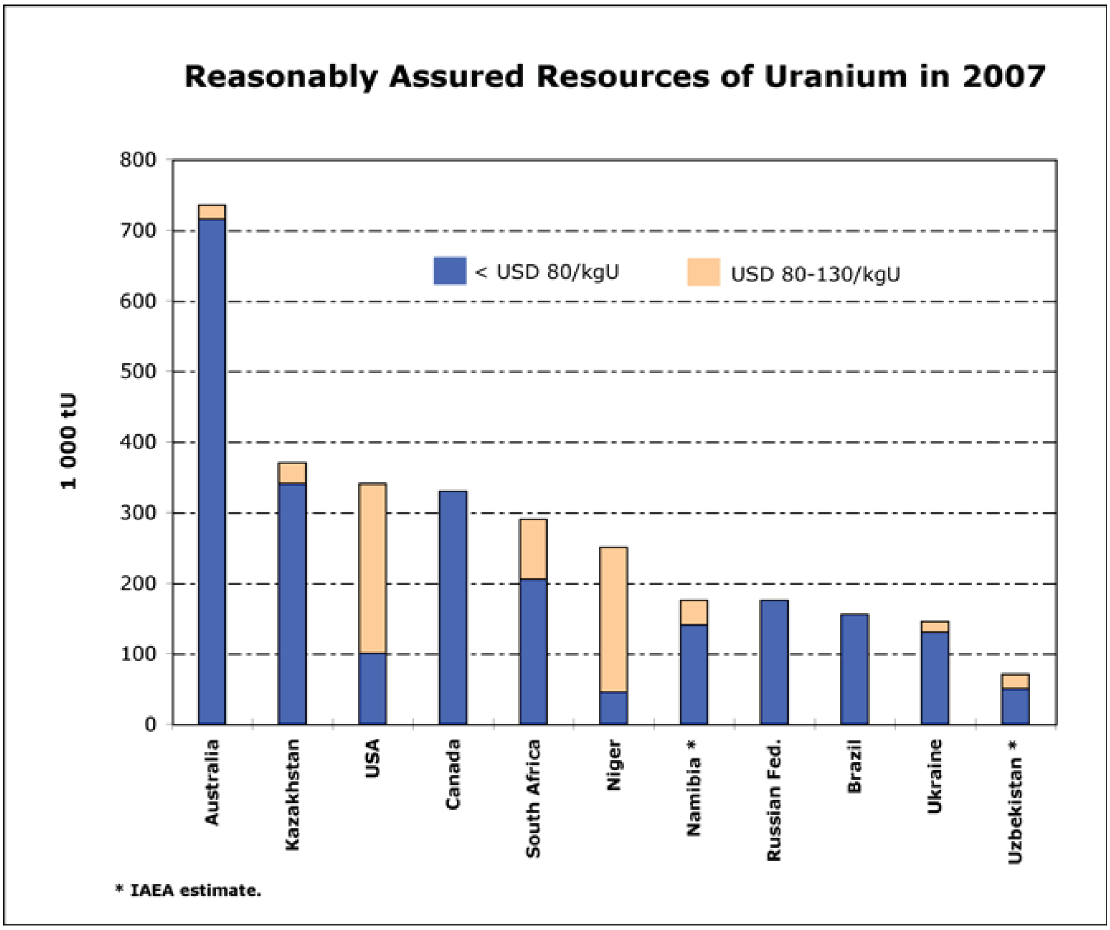
Sustainability	2010	2020	2030
Years Remaining	220	210	200

Source: SQW Energy

However, none of these calculations this takes full account of the other factors that are likely to extend the availability of uranium such as changing the tails assay in the enrichment process, increasing burn up in reactors, the use of recycled uranium and plutonium, the effect of increasing prices resulting from perceived shortfall in supply leading to further discovery through exploration and the continuation of technical innovation that has so far defeated the theoretical and possibly misguided focus on the significance of lower ore grades.

Figure 11.4 below shows the distribution of Reasonably Assured Resources in both the <US$40 per lb U_3O_8 and up to US$ 80 / lb U_3O_8. As can be seen, uranium resources are broadly distributed across all the continents (not including Antarctica) and offer considerable opportunity to diversify procurement risk away from any single geographical source.

Figure 11.4: Distribution of Reasonably Assured Resources in both <US$40 per lb U_3O_8 up to US$ 80 /lb U_3O_8



Source: WNA Sources of Uranium, 2007

Conversion

Unlike uranium extraction, conversion is a factory process that can be built to order. The major convertors in the world are shown in Table 11.7 below.

Table 11.7: Uranium conversion facilities worldwide

Facility (tU as $UF_{6\ natural}$)	Capacity 2007	Share of capacity (per cent)	Supply 2010
France – Areva	16,500	24	14,000
Canada / UK – Cameco	19,260	28	15,500
Russia – Atomenergoprom	17,760	26	5,500
US – Converdyn	13,000	19	14,000
Others	1,920	3	20,800
TOTAL	68,440		69,800
Demand	61,000		62,500
Capacity Margin	7,440	12	7,300

Source: Supply in 2010, WNA Enrichment (2008); 2007 capacity, ESA Annual Report (2007)

Conversion capacity currently exceeds demand and runs at less than full capacity allowing inventories to make up the difference. Conversion capacity is expected to grow as is demand for conversion. Converdyn have announced plans to increase capacity to between 23,000 and 26,000 tonnes by 2020 (Reuters 2008) which would restore a reasonable capacity margin without the need to draw down inventories. It is perhaps significant that all except Converdyn are involved in other stages of the fuel cycle and therefore the remaining converters have a strong strategic interest in maintaining and developing low cost conversion capacity.

Enrichment

Table 11.8 below show the major sources of enrichment.

Table 11.8: Major sources of enrichment worldwide

Facility	Capacity (tSWU) 2006	Share of Capacity (per cent)	Capacity (tSWU) 2015
France – Areva	10,800	18	7,500
Germany-Netherlands-UK - Urenco	9,000	15	12,000
Japan – JNFL	1,050	2	1,500
USA – USEC	11,300	19	3,500

USA – Urenco	0	0	3,000
USA - Areva	0	0	1,000
Russia - Atonenergoprom	25,000	43	33,000
China – CNNC	1,000	2	1,000
Other	300	1	300
TOTAL	58,450		62,800
Demand	48,248		60,000
Capacity margin	10,202	21	2,800

Source: WNA Enrichment, 2008

There is currently a substantial capacity margin which will diminish against a background of rising demand unless new plant comes on line. Construction of a new plant commenced in France in 2006 and is expected to add a further 7.5 million SWU per annum capacity between 2009 and 2016. A new enrichment facility is being built in the US that will compete domestically with USEC. By 2012, Urenco plans to increase its own capacity to 15 million SWU per annum. It will be readily capable of extension to a capacity of 11 million SWU per annum if there is market demand. Atomenergoprom is also increasing its capacity through the replacement of old centrifuges with more efficient new ones[7].

Unless inventories continue to be available into the future, short term interruption to supplies of enriched uranium may be possible because of vulnerability of the supply chain to the failure of part of any single enricher.

Apart from the possibility of a plant failure, the enrichment supply chain has suffered minor disruption from time to time as a result of the activities of a very small number of people who have been determined to disrupt transportation links between Urenco's enrichment plants and convertors and fuel fabricators. Such activities appear to have become much less frequent than in the past and have had no effect on electricity consumers or reactor output. Although there have been numerous traffic accidents involving uranium transportation, none of them have caused any interruption to electricity supply.

The highly diversified sources of nuclear fuel ameliorate exposure to imports. A contractual portfolio amongst the most stable supplier countries can be selected to ensure security of supply. Also, the international legal system and security that surrounds uranium transcends the normal commercial trading conditions that may prevail for other fuels, and enjoys a high degree of state protection. For example, Russia has never defaulted on a Uranium supply obligation in the last 40 years of trading.

7 ESA Annual Report , 2007, *Euratom Supply Agency Annual Report 2007*

11.2.1: Prices

Structure

Front End Fuel costs comprise the sum of:

- the cost of natural uranium ore as tri-uranium octoxide (U_3O_8) comprising U^{238} containing 0.711 wt% U^{235};
- the cost of conversion of the ore to natural uranium hexafluoride ($UF_{6\ natural}$);
- the cost of enriching $UF_{6\ natural}$ into enriched uranium product (EUP) to a specified percentage by weight in the U^{235} isotope ($UF_{6\ enriched}$) and to a specified percentage by weight in the U^{235} isotope ($UF_{6\ depleted}$) tails assay and tails disposal;
- and the cost of fabrication of EUP into finished fuel elements ready for loading into the reactor; and
- All ancillary costs such as shipping, weighing, sampling etc, which are very small in relation to the above costs and therefore assumed to be included in the prices.

This entire process is referred to as the "Front End Fuel Cycle".

Analytical Method

The quantities of each component required depend critically on a self-consistent set of analytical assumptions. For example, the quantity of EUP derived from the process depends on the tails assay selected. The optimum tails assay depends on the relative cost of the enrichment process compared with the cost of uranium ore. This consistency is ensured by carrying out the Fuel Cost calculation using the SQW Energy Nuclear Fuel Model. The mathematical basis for the enrichment cascade calculations is based on standard industry practice[8].

The choice of enrichment level, fuel burn up, fuel element dwell time, thermal efficiency and fabricated fuel type is dependent on choice of reactor design. For the purposes of this study, the AP1000 design is used as the reference technology (Westinghouse AP1000) and reactor performance is based on WANO data[9]. The key technical assumptions are shown in Appendix B.

Uranic Component Prices

The three commodities (U_3O_8, $UF_{6\ natural}$ and $UF_{6\ enriched}$) and two services (conversion and enrichment) traded on the world uranics markets, are subject to short term volatility in response to day to day, month to month and year to year. The recent price spike in uranium caused by short term speculator hoarding is an extreme example. Here we take a view based on fundamental cost of recovery and cost of processing fundamentals.

Figure 11.5 below show the development of uranium prices over the very long term commencing in 1948 to the price spike of last year. Figure 11.6 shows the development of prices over the past two years[10].

The charts show two very large excursions which have specific event-driven explanation. The first, in the late 1970s was driven by the activities of an illegal uranium cartel which sought

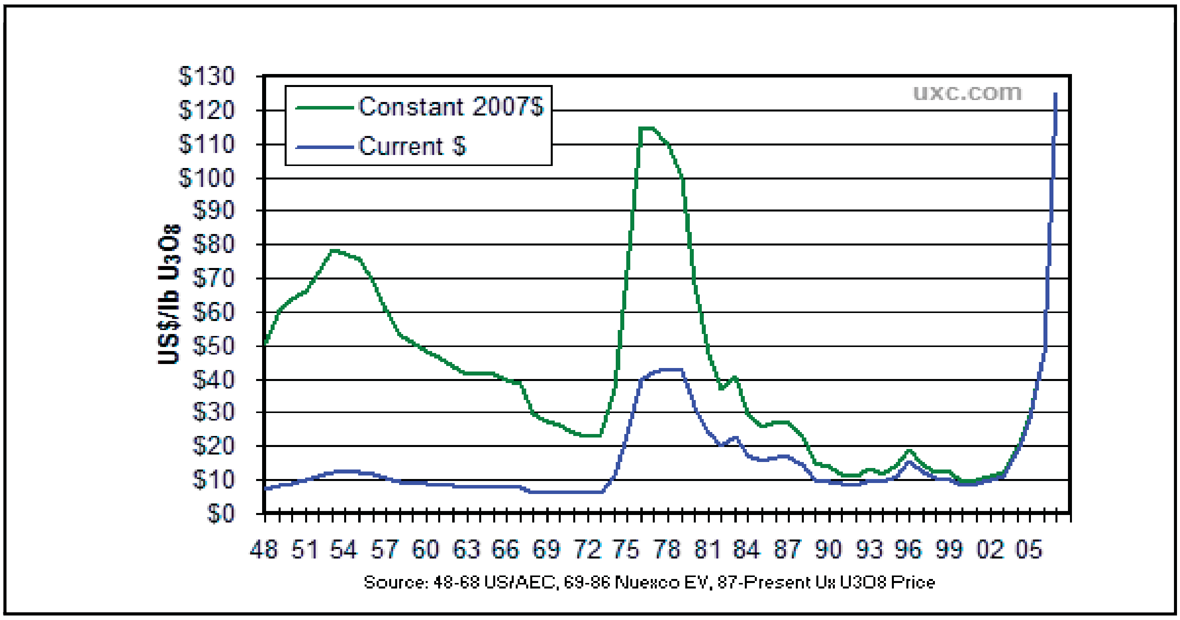
8 SIPRI, 1983, *The General Principles of Uranium Enrichment 1983*

9 World Association of Nuclear Operators (WANO), 2007, *Performance Indicators* 2007

10 UX Historic U308prices, 2008

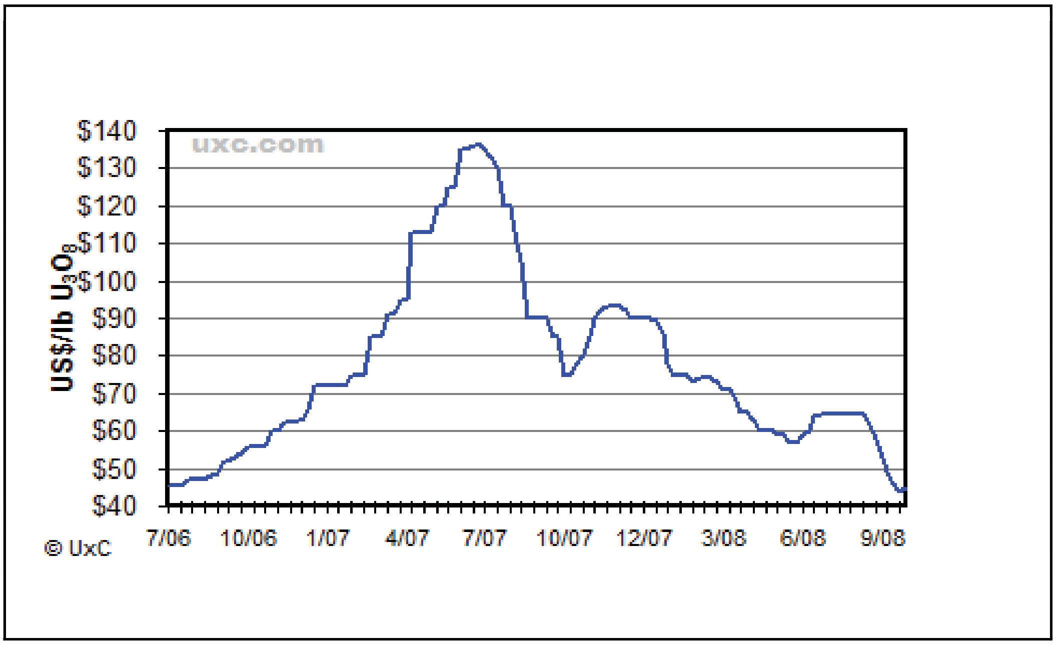
to restrict uranium supply in order to drive up prices. The decreasing prices after that peak were driven largely by free access to uranium production and the drawdown of very large inventories (including weapons materials). The second, peaking about a year ago, was largely driven by speculators hoarding uranium. More typical over long periods are the prices of the order that we see today.

Figure 11.5: Historic natural uranium prices, 1948-2005



Source: UX Consulting Company LLC

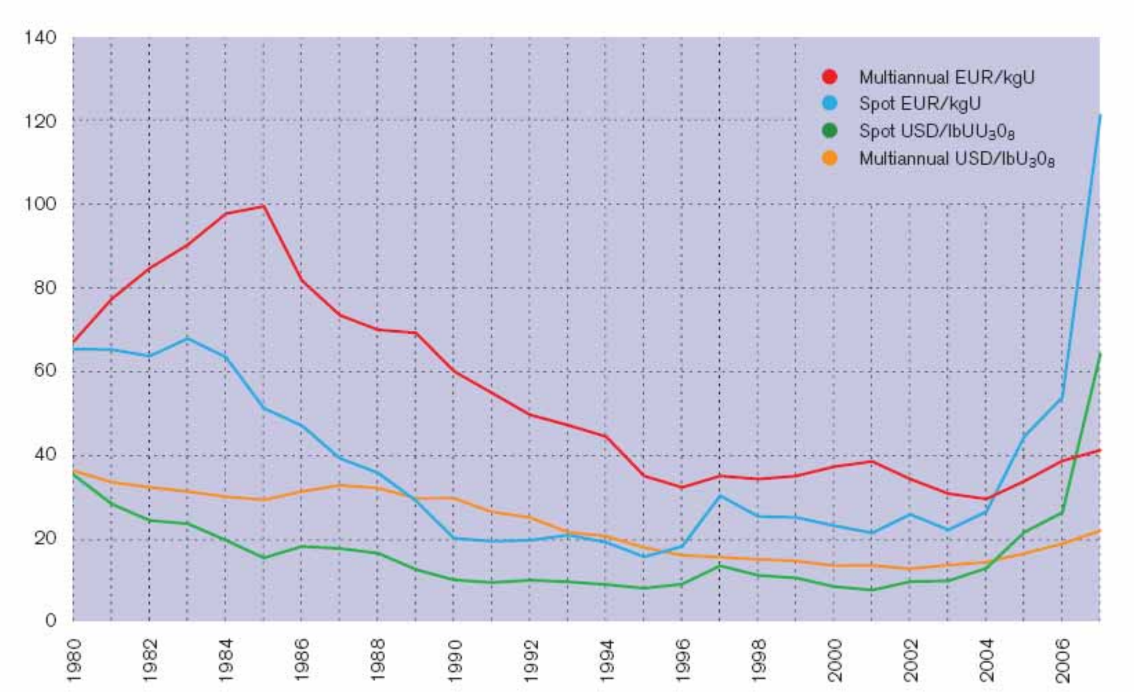
Figure 11.6: Recent historic natural uranium prices, 2006-2008



Source: UX Consulting Company LLC

Going forward, the analysis carried out by the OECD suggests a similar picture. As demonstrated above, at present consumption rates of uranium (and even slightly higher rates) uranium should be available at prices that are broadly similar to today's prices through to 2030. For this reason, for the purpose of this study, we assume a uranium price in real terms equal to the spot price published of US$43 per lb U_3O_8[11]or US$39.62 per lb U_3O_8 in 2006 money values. This price indicator has been showing a halt to the strong downward trend from the previous peak and towards a level that is reasonably consistent with the OECD Red Book figures as well as long term historic prices. This price is somewhat higher than delivered prices in Europe in recent years (see Figure 11.7 below) but this provides some allowance for what was perceived by many market players to be a historically depressed market as a result of inventory liquidation.

Figure 11.7: EU Average prices for natural uranium delivered under spot and multiannual contracts, 1980 – 2007



Source: Euraton Supply Agency Annual Report (2007)

Conversion Prices

Conversion prices are not driven by a natural limitation on availability of resource as is the case for virgin uranium. Conversion is a factory operation and once built, it needs to amortise costs and compete with other suppliers on the basis of marginal cost. Other key cost inputs include electricity and fluorine costs. Conversion processes are likely to become more efficient and cost effective over time and prices might be expected to fall in real terms. Historically, the picture has not been quite so simple because of the relatively limited number of converters in the world. Nevertheless, investment is proposed against the

11 UX Consulting Company LLP, 27th October 2008

background of today's spot market prices of US$9.75 /kg U[12]. For these reasons we use the current price of US$9.75 /kg U, or US$8.98 /kg U in 2006 money values for the calculation of the index maintained in real terms through to 2030.

Enrichment Prices

The same general principles apply to enrichment as conversion, both being factory operations. A key point to note is the very low contribution that energy prices make in the total costs of enrichment. We therefore believe that the current spot price of US$159/SWU is reasonable for the whole period.

We have added a cost of US$5.31 / kg U as UF_6 (LES, 2006) expressed in 2006 money values for the disposal of tails, although in many cases, this would be included within the contract price. This is based on evidence given in the US in relation to the development of a new enrichment facility in Louisiana, LES (2006). This brings the total cost of enrichment to US$151.82 /SWU in 2006 money values.

Fabrication Prices

Fabrication is also fundamentally a factory operation in a market which suffers from relatively little competition. We use here the generic indicative fabrication price reported by the World Nuclear Association of US$240 per kgU (WNA Enrichment, 2008), or US$233.35 per kgU in 2006 money values.

Table 11.9 below summarises the range of projected nuclear prices in 2010, 2020 and 2030. For the competitiveness element of the fuel calculation, the price of nuclear fuel delivered to the reactor has been calculated with no allowance for disposal costs at this stage.

Table 11.9: Projected nuclear prices in 2010, 2020 and 2030 in € per GJ (2006 money values)

Date	2010	2020	2030
Nuclear price - value used in the Index	€1.29	€1.29	€1.29

Source: SQW Energy Nuclear Fuel Model

11.2.2 Weighted import dependence

All fuel would be imported into Ireland and there is no obvious reason why additional capacity for any of the stages of the fuel cycle would be constructed in Ireland itself. A single AP1000 could generate about one third of the whole country's electricity requirements. However, this would leave the electricity network highly vulnerable to reactor trips and the costs of putting in place reserve capacity to maintain security of electricity supply is likely to be prohibitive.

The reactor could provide energy to sectors which may not have instantaneous requirements, so the risk to electricity consumers or any other single sector may not be so great. For example, electricity can be used to charge electric cars and waste heat could be used for industrial heating.

12 UX Historic U3O8 prices, 2008, UX Consulting Company LLP, 27th October 2008

11.3: Nuclear energy in the energy system

11.3.1 Delivered energy cost

BNFL (2004) presents the expected levelised cost of electricity generated by the AP1000 (inclusive of all lifetime costs, including capital and waste management), the reference technology for this study. A summary of the analysis is shown in Table 11.10.

Table 11.10: Indicative full costs of the AP1000

Cost item	US$ per MWh 2002 MV	US$ per MWh 2006 MV	€ per MWh 2006 MV	€ per GJ 2006 MV
Capital	21.32	23.78	18.87	5.24
Operating	9.01	10.05	7.97	2.21
Fuel	4.65	5.19	4.12	1.14
Spent fuel	0.45	0.50	0.40	0.11
Waste disposal	0.45	0.50	0.40	0.11
Decommissioning	0.75	0.84	0.66	0.18
TOTAL COST	36.64	40.86	32.43	9.01

Source: BNFL (2004), SQW Energy

These calculations depend critically on the following assumptions:

- The plant is a first of a kind and 15 per cent more expensive than follow-on units, but will be a twin plant;
- Construction takes place over 5 years at a cost of £2,220M in 2002 money values and includes the first fuel core;
- Post tax discount rate of 7 per cent;
- Nuclear liabilities revalorisation rate of 2.5 per cent;
- 30 year economic life (compared with 60 year design life); and
- Load factor averaging 90 per cent.

The figures stated by BNFL (2004) make assumptions regarding uranics prices that are different from those of SQW Energy reflecting market movement over the past five years. The following adjustments are required to correct for the levelised cost of electricity.

Table 11.11: Uranics market price movements

Item	BNFL 2002 MV	BNFL 2006 MV	SQW 2006 MV	Adjustment €/GJ
U_3O_8 price ($/lb)	9.00	10.04	39.62	0.34
Conversion ($/kg U)	5.00	5.58	8.98	0.01
Enrichment ($/SWU)	90.00	100.41	151.82	0.25
TOTALS	104.00	116.03	200.42	0.60

Source: SQW Energy

Table 11.12 below summarises the range of projected delivered energy prices in 2010, 2020 and 2030 taking into account the market price movements.

Table 11.12: Projected delivered energy prices in 2010, 2020 and 2030 in € per GJ 2006 money values

Date	2010	2020	2030
Nuclear price - value used in the Index	€9.61	€9.61	€9.61

Source: SQW Energy

11.3.2: Policy and regulation

The uranics markets are regulated by a well established framework of international law, European law and, if reactors were to be built in Ireland, by Irish law. The supply chain is populated with experienced, reputable suppliers who are generally well known to each other. Procedures for trading follow normal, well established international practices.

The major deficiency in the uranics markets is the absence of a traded market. This means that deals are done on a confidential and long term basis in anticipation of poor market liquidity, although buyers and sellers are very aware of market prices. In time, it is likely that the uranics markets will become more regulated. A possible leading indicator is the recent interest of speculators who until recently ignored uranium as an investment. Enabling uranics traded commodities and services to become part of a standard liquid market could be of value to investors and traders. We assume therefore an improvement from 2020.

Nuclear safety regulation on the scale that would be necessary to support the development of industrial scale nuclear capacity has not yet developed in Ireland. Developing such a capability is not a trivial task as was explained in the introduction. This presents a regulatory barrier at the outset.

Further, there is the reality of getting planning permission for a new nuclear station taking account of public acceptability. This is likely to be a significant barrier to development. There are currently no direct incentives for using nuclear energy in Ireland. Nevertheless, the absence of particulate emissions and carbon emissions at the point of generation means that nuclear does not suffer from the operational limitations (such as those arising from the Large Plant Combustion Directive) or additional operational costs (such as those that arise from the need to acquire a percentage of European Emissions Allowances at cost through auctions). This has the effect of allowing nuclear generation partially to benefit from its low environmental impact in these areas compared with some fossil fuels whilst bearing the full costs of nuclear energy's actual environmental impact.

11.3.3: Supply chain and infrastructure resilience

Places of extraction, manufacture and processing are extremely secure and operate to exceptional standards of safety. Transport is the weakest element in theory, but in reality, the uranics work in progress as well as the reactivity of reactor cores provides significant buffer time in the event of transport delay. SQW Energy are not aware of any disruption to electricity supplies having occurred as a result of infrastructure security issues.

11.3.4: Market context in Ireland and market volatility

There is no nuclear capacity in Ireland and the policy framework described above virtually precludes one from being developed in the near future. This also means that currently there is limited (if any) domestic capability to explore the nuclear option – any such capability will have to be brought in from outside Ireland.

There is sufficient capacity to meet demand at all stages of the fuel cycle as discussed above. Moreover, there are significant flexibilities possible in obtaining uranic material for fuel manufacture. For example: natural UF_6 can be purchased rather than the combination of U_3O_8 and conversion; enriched uranium product can be purchased readymade and blended to derive the desired enrichment level; tails assay can be varied to exchange a SWU requirement for a uranium requirement; location swaps are routine and so on. As discussed, there is no cleared trading system for uranium, which does leave sellers exposed to a buyer's credit risk and vice versa. In the early 1990s a major uranium trader went into liquidation owing huge amounts of uranium to many parties around the globe, but even then, there was no consequent disruption to electricity supply.

11.3.5: Environmental impacts

Nuclear waste is created in very small volumes indeed compared with fossil wastes. It is fully managed, monitored, contained and accounted for from cradle to grave. It does not normally create particulate pollution when handled properly. High level waste is highly immobile both physically and radiologically compared with captured carbon or other fossil wastes[13] and the

13 Sustainable Development Commission (SDC), 2006, UK, Waste and Decommissioning: An evidence based report by the Sustainable Development Commission with contributions from Nirex and AMEC NNC

radioactive half-life time-limits the most serious radiological threats compared with conventional pollutants.

Mortality rates from nuclear generation are considerably lower than from fossil fuels, biomass or wind (Wind Mortality Rates, 2001; Electricity Generation and Health, 2007). The major negative issues arise if there is a significant accident. The history and ever more sophisticated focus on safety do not clearly support that it is dangerous and the evidence to date suggests that it may be one of the safest sources of energy. Nevertheless, the perception of risk from nuclear is that a serious incident could be so catastrophic as to outweigh all the safety benefits that have accrued to date.

11.4: Nuclear energy and climate change

11.4.1: Carbon content of fuel

The nominal carbon emission during the process of nuclear fission is nil and has a value of 0 tCO_2/TJ.

11.4.2: Lifecycle carbon footprint

The global warming potential of delivered electricity based on a life cycle analysis is highly dependent on circumstances, which explains why there is often such controversy surrounding these figures. Hundreds of studies have been carried out giving a very wide range of results. A recent paper (Energy Policy, 2008[14]), critically reviewed 103 studies from around the world covering a wide range of circumstances. In the author's opinion, the average emissions from all the qualified studies was 66 gCO_2eq/kWh, with a low end of 15 gCO_2eq/kWh. There is scope to target a desired level of emissions at the low end, rather than accept the average. For the purposes of a reference case for this study, the average will be used. We therefore assign a value of 66gCO_2e/kWh or 0.0167 tCO_2/TJ.

11.4.3: Supply and infrastructure vulnerability

The supply chain has potential vulnerabilities to the availability of water, transport disruption by sea and land, extreme heat and cold and storms. Nevertheless, by its nature, uranium mining in particular has adapted to almost any possible condition already. Moreover, because of the very high energy content in any given volume of uranic fuel compared with fossil fuel, transport of the fuel takes place at discrete intervals and does not have the almost continuous transport requirement of fossil fuels. For these reasons, uranium fuel is likely to be highly resilient to the effects of climate change compared with fossil fuels. We do not know specifically whether any key fuel cycle facilities are located in vulnerable positions.

Of much more significance is the choice of site for a nuclear reactor. Temperature rise is likely to affect the efficiency of the station, causing it to waste more heat. Storm surges could pose a physical threat to the equipment on the station where it is located near to the sea. Rising sea levels could undermine the site entirely. These effects will certainly be highly significant over the life of a nuclear reactor but the key is to ensure that the station is sited where it will not be affected. Since the station has not been constructed yet, there is every reason to believe that climate change will not be given access to damage the station infrastructure.

11.4.4: Availability change of the resource

There is no expected change in the availability of uranium as a result of climate change.

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14 Energy Policy, 2008, *ScienceDirect Energy Policy Valuing the Greenhouse Gas Emissions from Nuclear Power: A critical survey* February 2008

Appendix A: World Nuclear Power Reactors 2007-2008

	NUCLEAR ELECTRICITY GENERATION 2007		REACTORS OPERABLE Oct 2008		REACTORS UNDER CONSTRUCTION Oct 2008		REACTORS PLANNED Oct 2008		REACTORS PROPOSED Oct 2008		URANIUM REQUIRED 2008
	billion kWh	per cent	No.	MWe	No.	MWe	No.	MWe	No.	MWe	tonnes U
Argentina	6.7	6.2	2	935	1	692	1	740	1	740	123
Armenia	2.35	43.5	1	376	0	0	0	0	1	1,000	51
Bangladesh	0	0	0	0	0	0	0	0	2	2,000	0
Belarus	0	0	0	0	0	0	2	2,000	0	0	0
Belgium	46	54	7	5,728	0	0	0	0	0	0	1,011
Brazil	11.7	2.8	2	1,901	0	0	1	1,245	4	4,000	303
Bulgaria	13.7	32	2	1,906	0	0	2	1,900	0	0	261
Canada	88.2	14.7	18	12,652	2	1,500	3	3,300	4	4,400	1,665
China	59.3	1.9	11	8,587	7	6,700	26	27,620	76	62,600	1,396
Czech Republic	24.6	30.3	6	3,472	0	0	0	0	2	3,400	619
Egypt	0	0	0	0	0	0	0	0	1	1,000	0
Finland	22.5	29	4	2,696	1	1,600	0	0	1	1,000	1,051
France	420.1	77	59	63,473	1	1,630	0	0	1	1,600	10,527
Germany	133.2	26	17	20,339	0	0	0	0	0	0	3,332
Hungary	13.9	37	4	1,826	0	0	0	0	2	2,000	271
India	15.8	2.5	17	3,779	6	2,976	10	9,760	15	11,200	978
Indonesia	0	0	0	0	0	0	2	2,000	2	2,000	0
Iran	0	0	0	0	1	915	2	1,900	1	300	143
Israel	0	0	0	0	0	0	0	0	1	1,200	0

Japan	267	27.5	55	47,577	2	2,285	11	14,945	1	1,100	7,569
Kazakhstan	0	0	0	0	0	0	0	0	2	600	0
Korea DPR (North)	0	0	0	0	0	0	1	950	0	0	0
Korea RO (South)	136.6	35.3	20	17,533	3	3,000	5	6,600	2	2,700	3,109
Lithuania	9.1	64.4	1	1,185	0	0	0	0	2	3,400	225
Mexico	9.95	4.6	2	1,310	0	0	0	0	2	2,000	246
Netherlands	4.0	4.1	1	485	0	0	0	0	0	0	98
Pakistan	2.3	2.34	2	400	1	300	2	600	2	2,000	65
Romania	7.1	13	2	1,310	0	0	2	1,310	1	655	174
Russia	148	16	31	21,743	7	4,810	12	14,340	25	22,280	3,365
Slovakia	14.2	54	5	2,094	2	840	0	0	1	1,200	313
Slovenia	5.4	42	1	696	0	0	0	0	1	1,000	141
South Africa	12.6	5.5	2	1,842	0	0	1	165	24	4,000	303
Spain	52.7	17.4	8	7,448	0	0	0	0	0	0	1,398
Sweden	64.3	46	10	9,016	0	0	0	0	0	0	1,418
Switzerland	26.5	43	5	3,220	0	0	0	0	3	4,000	537
Thailand	0	0	0	0	0	0	0	0	4	4,000	0
Turkey	0	0	0	0	0	0	2	2,400	1	1,200	0
Ukraine	87.2	48	15	13,168	0	0	2	1,900	20	27,000	1,974
United Kingdom	57.5	15	19	11,035	0	0	0	0	6	9,600	2,199
USA	806.6	19.4	104	100,599	0	0	12	15,000	20	26,000	18,918
Vietnam	0	0	0	0	0	0	0	0	2	2,000	0
WORLD	2,608	15	439	373,247	36	29,848	99	108,675	232	211,575	64,615

Source: (WNA Reactor Requirements, 2008)

Appendix B: Assumptions for fuel characteristics based on the AP1000

Parameter	Assumption	(Source) Comment
Enrichment level	4.95 wt per cent U^{235}	(Westinghouse AP1000). EUP converted to UO_2 for fabrication into finished fuel
Enrichment tails assay	0.2 wt per cent U^{235}	Although tails at 0.3 per cent common in 2007, some utilities are now moving to 0.2 per cent. ESA Annual Report (2007).
Conversion losses	0.50 per cent	This is the additional feed required to compensate for process losses
Fabrication losses	0.50 per cent	This is the additional enriched uranium product required to compensate for process losses
Reactor Thermal Power	3,400MWth	(Westinghouse AP1000)
Reactor electrical output at station gate	1,117 MWe	(Westinghouse AP1000)
Thermal efficiency	32.85 per cent	(Westinghouse AP1000). Slightly higher than in the source document (32.7 per cent) to align thermal and electrical power figures.
Fuel burn up	60,000 MWd/te	(Westinghouse AP1000). Initial and final core variations ignored
Capacity factor	83.70 per cent	(WANO (2007)). Based on the WANO Unit Capability Factor[15] less the Unplanned Capability Loss Factor[16], both for 433 nuclear units worldwide in 2007. An AP1000 would be expected to perform at higher than this level.

15 Unit Capability Factor is the percentage of maximum energy generation that a plant is capable of supplying to the electrical grid, limited only by factors within control of plant management. A high unit capability factor indicates effective plant programmes and practices to minimise unplanned energy losses and to optimise planned outages.

16 The unplanned capability loss factor is the percentage of maximum energy generation that a plant is not capable of supplying to the electrical grid because of unplanned energy losses, such as unplanned shutdowns or outage extensions. A low value indicates important plant equipment is well maintained and reliably operated and there are few outage extensions.

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