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Queensland Parliament

ENVIRONMENT AND RESOURCES COMMITTEE

GROWING QUEENSLAND'S RENEWABLE ENERGY ELECTRICITY SECTOR

SUBMISSION

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Tables and Figures

Abbreviations

AC – Alternating Current
AEMO – Australian Energy Market Operator
AER – Australian Energy Regulator
BRCI – Benchmark Retail Cost Index
CEA - Clean Energy Australasia Pty Ltd
CSO – Community Service Obligations
DC – Direct Current
FIT – Feed in Tariff
LRMC – Long Run Marginal Cost
NEM = National Electricity Market = AEMO = Australian Energy Market Operator
PV - photovoltaic
QCA – Queensland Competition Authority
QREF – Queensland Renewable Energy Fund
NREL – National Renewable Energy Laboratory
RAB – Regulated Asset Bas
RAPAD – Remote Area Planning and Development Board
REP – Renewable energy Plan
RET – Renewable Energy Target
SRET – Small Renewable Energy Target

Units

kWh = kilo watt hour = 1000 watt hours
MWh = mega-watt hour = 1 million watt hours
MWe = mega-watt electric
GWh = giga-watt hour = 1000 million watt hours
PJ = peta-joules = 10^{15} joules

Parliamentary Inquiry – Growing Queensland's Renewable Energy Electricity Sector

Executive Summary

1. The Queensland government should expand the use of renewable energy sources to generate electricity as follows;

    i. Ensure the mix of renewables matches the requirements of the community by increasing the contribution of base load energy sources for power generation e.g. geothermal and reducing dependence on intermittent energy sources such as wind and solar.

    ii. The present renewable energy target for electricity is based on 1997 base line consumption. With population growth and increased economic activity the longer we go without adjusting the target the less effective the target will become. It is essential to; at least, adjust the target for growth at a minimum.

2. There are a great number of barriers to entry as set out in this paper. Many are discriminatory as between renewable energy sources. In particular Government policy, actions and the Renewable Energy Plan itself positively discriminate against geothermal energy.

3. A number of investments sponsored by the Government are, on the face of it, of doubtful value to the community. Examples in solar generated electricity are the concerns with the Windorah, Cloncurry and Townsville projects. Examples in geothermal are both the lack of investment in the geothermal industry and the total investment focus on government owned or related corporations such as the Birdsville project and the coastal drilling initiative. As well, the terms of this inquiry do not address the significant Queensland government investment in carbon capture and storage (CO_2 geosequestration from coal fired power stations) the commerciality of which is highly doubtful in the international scientific community.

4. The hot water rebate should be extended to cover all fossil fuel replacement. Support for industries that maximise Queensland employment and minimise export of jobs must be paramount. Furthermore financial assistance should be crafted so as to remove the boom and bust cycle that has been prevalent both in Australia and overseas. Removal of discriminatory policies and picking winners is essential to achieving long term distortion free development of renewable industries.

5. Setting State targets is an essential element to achieving certainty for industrial and economic adjustment. The targets should not be confined to electricity.

6. A reasonable electricity target for 2020 would be 13800GWh out of a total target for all energy consumption of 267PJ.

7. Properly crafted incentives for investment and a sound policy framework are essential for the successful movement into renewable energy. Feed in tariffs may not be as useful as thought. Bounties do not try to pick winners and have been successful in Australia's development history. Bounties in the form of exploration drilling subsidy were extremely successful in establishing the petroleum industry in Australia in the late fifties early sixties. A similar approach could be pursued for developing renewable energy sources e.g. geothermal exploration drilling subsidy.

Inquiry Questions:

1. Should the Queensland Government aim to expand the use of renewable energy sources to generate electricity?
2. What are the barriers to increased use of renewable energy for generating electricity and associated investment in Queensland?
3. What have the Queensland Government's own investments in renewable energy projects for the generation of electricity achieved to date, and at what cost?
4. What are the priority issues the Queensland Government should address to encourage investment in renewable energy for the generation of electricity?
5. Should the Queensland Government set a State target, or targets, for the proportion of electricity generated from renewable energy sources?
6. If so, what should the targets be, and what form should they take?
7. What actions should the Queensland Government take to encourage investment in generation and co-generation of electricity from renewable energy sources?

Question 1 Expand the Renewable Energy Target for Electricity

1. The renewable energy plan (REP) seems to adopt a renewable energy target for Queensland of 20% of the Australian target of 45000 GWh per annum by 2020. So the REP has established a target of 9000 GWh per annum and set about devising a plan to achieve that target. This 20% figure, which equates to 4% of Australia's base-line generation, seems loosely to be based on Queensland's share of base-line 1997 figures used to establish the renewable energy target (RET) for Australia. The concept of setting a target that is reducing daily by growth in consumption is self defeating. By its own figuring the Queensland Government acknowledges in the REP that it will generate 69000 GWh in 2020. Applying the 20% renewable energy target to this number gives **13,800** GWh of renewable energy generation required in the same year just for Queensland to carry its fair share of the national burden. Moreover, Queensland's share of electricity generation is a growing proportion of the Australian total. As a consequence Queensland's fair share of the RET burden is increasing.
2. Irrespective of the climate change debate, reliance on fossil fuels exacerbates a dependency that is unsustainable in the long term. The sooner this constraint is recognised, the sooner future Queenslanders will reap the benefits of the foresight of their forefathers.
3. The oft argued position of Queensland's revenue and quality of life depends on the production of coal for use in Queensland's power stations simply does not stand scrutiny. Reducing dependency on fossil fuels within Queensland does not necessarily put at risk Queensland's export revenue derived from mining fossil fuels. There is no interdependence between the two pursuits.
4. There are dual policy objectives in respect of renewable energy use. One is to reduce the release of green-house gases; and one is to reduce a very high level of dependence on a single fuel energy source (coal). A high dependence on a single source runs contrary to the risk mitigation strategies of all portfolio management theories.
5. At the present SRET price for carbon at $40/MWh, 45000 GWh/year will cost the Australian electricity consumer $1.8 billion dollars per year in additional electricity charges. This factor should be recognised and the money channelled properly into renewable energy production and not the traders profits.
6. Australia's RET falls way short of the leaders. Europe's target of 20% relates to the **whole** of energy consumption not just electricity generation whereas Australia's only relates to electricity generation and consumption. Far more energy is consumed over and above that of electricity generation and should be covered in the RET if Australia is to be "dinkum".
7. In examining the expansion due regards should be made to the proper and appropriate mix of energy sources so that electricity production will match the load profiles of community demand. This will require a greater portion of base load renewable generation capacity such as that available from geothermal power, thereby reducing dependence on intermittent energy sources such as solar and wind.

Question 2 Barriers

Available technologies and technology development

At the present time available technologies being pressed into service for renewable electricity generation in Australia comprise: -

- Wind generation;
- Solar photovoltaic generation
- Solar thermal water heating (that displaces electricity); and
- Biomass co-generation.

All of these technologies are mature and are readily available from overseas sources. Apart from biomass co-generation their introduction into Australia has been supported by massive rebates and incentives that have themselves created barriers to entry for competing technologies such as geothermal power.

It is apparent when one peels away the rhetoric that the Queensland Government's policy objective is to foster solar and clean coal technologies to the exclusion of others.

The exclusionary powers of the Government create almost insurmountable barriers to entry of any competition

Availability of risk capital

Development and innovation in technology is a risky business. The Government is well aware that some risk sharing with the community is necessary to spread this risk and leverage the entrepreneurship of others.

A highly successful example is the Enertrade teaming with CH4 to establish the viability of the coal seam methane industry.

More recently, the Government has committed $300 million to leverage $600 million in risk capital for coal-related emission technologies.

The REP states that the plan will leverage $3.5 billion in investment but is silent on how this will be accomplished or what the leverage ratio will be.

At the present time, apart from investment by Government owned corporations that are directed by the Government, risk capital appears to be in extremely short supply; thereby imposing large barriers to entry for any private entrepreneurial endeavour.

Distortion from Government policy

Present Government policy clearly is to support almost exclusively solar based renewable energy technologies both financially and in promotional propaganda. There has been no debate as to how appropriate and at what level the adoption of various renewable technologies matches the requirements of the Queensland community or how the relative costs compare.

Examples of policy distortions are:-

The solar hot water rebate only applies to "electric" hot water replacement, gas consumers miss out. However, reducing consumption of gas also contributes to emission reduction and renewable energy consumption. Not only does this distort the market but also it causes one group of consumers to cross-subsidise another group.

The Solar Bonus Scheme applies only to photovoltaic roof mounted systems of 10KVA (single phase) or 30KVA (three phase) maximum capacity or less than 100MWh per year of consumption. This imposes an artificial constraint on the size of installations. When taken in conjunction with the federally sourced policy limiting solar credits to 1.5KW or smaller systems, a bias towards small system installation is introduced. Furthermore, the stipulation that the technology must be photovoltaic entrenches technology, eliminates competition from competing technologies and stifles innovation in the micro-generation space.

The REPs timetable for geothermal pilot in 2014 effectively puts on the "back-burner" advancement of geothermal technologies until the Government is ready. Geothermal pilots have been designed and are ready to go now. Moreover it is acknowledged that Queensland has the greatest potential of any State for a geothermal industry.

These are just a couple of examples of how Government's "picking winners" through policy formulation serve to artificially create very large barriers for emerging technologies and innovation.

Structure of electricity industry

Irrespective of all of the re-organisation of the electricity industry prompted by the Hilmer inquiry, 90% of the industry still is essentially a monopoly Government controlled business in which there is little or no competition. The reality of the facts is that the underlying business based on generation licences, the highly specified national electricity market and wires for transmission and distribution is a natural monopoly with enormous barriers to entry.

It is almost impossible to bring about competition in a natural monopoly environment. Society and especially Governments should recognise it for what it is and set about correcting the detriments.

In this regard, it should constantly be born in mind that organisations, no matter what their objective, are comprised of people dealing with, utilising and protecting assets of the organisation. All of the normal motivational drivers affect people in monopolies as in any other endeavour. This includes the "protecting the patch" syndrome; and the exercise of power conferred by the monopoly position.

There are numerous instances of these aspects amounting to barriers to entry of new and innovative energy sources. Most are anecdotal and will only surface if there is a proper inquiry into the workings of the present arrangements in Queensland.

However, CEA has direct experience with Ergon of self interest action. CEA representatives met with Ergon to discuss participation in a geothermal pilot project at Longreach. CEA's actions reflected the Government's advice in the REP concerning Government owned corporations. Ergon rejected out of hand any participation or involvement without reviewing any proposals at that time, and again at a later time in representations to the responsible Minister in the presence of CEA representatives. Shortly thereafter, Ergon made an application for waiver of ring-fence arrangements in respect of proposed installation of generation for network support in the same region.

Barriers to entry exist because of the structure that has inadequate supervision and a conflict of interest in the prosecution of Government policy.

Insufficient Government technical and scientific understanding and advice

The REP is an example of the shaping of policy in a vacuum. It establishes that 2635MW of renewable generation capacity is targeted by 2020. Within the identified generation mix 83% is intermittently available either seasonally, daily or instantaneously and cannot be scheduled. This means that not only can those supplies not be relied on but also generation can occur at times when there is absolutely no need and would back out other capacity. The consequence is that such supplies will need idle generation capacity in place to meet consumer demand when those generation sources cannot produce.

A prime example of this intermittency and scheduling issue occurred in South Australia during a summer heat wave. Lack of wind left all of the wind farms idle causing load shedding, and enormous strain on the gas-fired generation infrastructure.

Although the issue of intermittency is obliquely referred to in the REP it is patently apparent that the importance of the issue has not filtered through into the formulation of the plan.

The issue of intermittency had been dealt with in great detail by the House of Lords inquiry reported in November 2008; incidentally this was prior to the formulation of the REP.

In that report the Lords observed: -

"House-of-Lords pp 34

Intermittency—a constant problem?

98. Matching electricity supply to demand is challenging as it is not presently economic, or technically feasible, to store electricity on a large scale.
Electricity can be stored in batteries for portable applications but their costs are too high for use in the national electricity grid. Electricity generation must be matched to demand on a minute-by-minute basis, or power cuts result. Some power plants are therefore kept running at less than full load, to respond rapidly to a sudden increase in demand or to make up for a power plant failure elsewhere in the system. [32]
99. But not all power stations can be "dispatched" to change their output level quickly. Coal, gas- and oil-fired stations are generally straightforward though their response speeds vary. Nuclear stations are relatively inflexible, and are best operated at a constant (full) load. Renewable generators burning biomass, and hydro generators, can generally be dispatched.[33]
100. Wind, wave and tidal stations are inherently not dispatchable. They can only generate when conditions are right—if there is no wind, or too much wind, no electricity can be produced. Tidal generators can produce much more at the spring tides (with a high variation in the water level) than at neap tides (low variation). The tides are predictable far in advance, but the wind is almost impossible to forecast more than a few days in advance, and even day-ahead forecasts can be inaccurate.

House-of-Lords pp 35
Fluctuations in wind speed lead to short term changes in electricity output from wind farms. Greater use of wind power and other intermittent renewable sources therefore requires more backup generation capacity to respond very quickly to, for example, reductions in the output of wind turbines when the wind drops. But the technical challenges and costs of backup generation on a scale large enough to balance an electricity system with a high proportion of intermittent renewable generation are still uncertain. There is currently no experience elsewhere in Europe of the scale of dependency on intermittent renewables expected in the UK. **Whereas the highest share of intermittent renewable electricity now being generated is 15% in Denmark, the UK is expected to reach a share of some 30%–40%. We recommend that the Government should ensure that further work is carried out to clarify the costs and encourage development of technical solutions to deal with intermittency.**

35 For the purpose of comparison current total generation capacity is 76 GW. The amount of spinning reserve
that National Grid holds is currently based on the size of the largest single generator on the system. This allows the company to cope with any single failure, on the basis that the near-simultaneous failure of two large generators is sufficiently unlikely.
36 Sinclair Knight Merz (2008) *Growth Scenarios for UK Renewables Generation and Implications for Future*
Developments and Operation of Electricity Networks BERR Publication URN 08/1021
37 SKM presented these costs as 0.07 pence per kWh of **total** generation in a scenario with low levels of wind
power (3.1%), and as 0.45 pence per kWh of **total** generation in a scenario with wind power making up

27.1% of total generation (table 7.12). We divided the difference of 0.38 pence per kWh by 27.1% to give the figure for the increased cost per kWh of wind generation.

38 Gross, R., P. Heptonstall, D. Anderson, T.C. Green, M. Leach and J. Skea (2006) *The Costs and Impacts of*
Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British
electricity network, London, UK Energy Research Centre.

36 THE ECONOMICS OF RENEWABLE ENERGY

House-of-Lords pp36

The second cost due to intermittency comes from the need to have enough capacity available to meet peak demand. No power station is guaranteed to be available at peak demand. So the industry holds extra capacity over and above the expected peak demand to cope with stations that turn out not be available when most needed, or higher than expected demand. As a rule of thumb, a 20% margin of extra capacity has been sufficient to keep the risk of a power cut due to insufficient generation at a very low level, given the characteristics of the current system.

107. A fossil-fuelled station has around a 5% chance of not being available to generate at the time of the system peak because of breakdowns or essential maintenance (p 119). One plant's breakdown is rarely correlated with another. Nuclear plants have a similar risk, although they sometimes suffer from generic issues that require maintenance at all of the stations of a similar design.

108. But for renewables it is very different. At peak demand not only are the chances of a wind farm not being fully available much higher but it is very likely that, if so, nearby wind farms will also be at least partially unavailable because it is not windy in the area. This correlation will fall for distant wind farms—for example, the wind could well blow in Scotland when conditions in Cornwall are calm. But within the UK, the correlation does not fall to zero.

109. As a result, the proportion of renewable generation which can be relied on at peak demand is much lower than for fossil fuel plants and more complicated to calculate. We received several estimates of how far wind capacity could be counted on to contribute to meet peak demand—its "capacity credit". BERR uses a range of between 10% and 20% of wind stations' capacity, so that 25 GW of wind plant could displace between 2.5 and 5 GW of conventional plant (Q 483). E.ON suggest that the capacity credit of wind power in the UK should be only 8% (p 119).

39 Department for Business, Enterprise and Regulatory Reform (2008), *UK Renewable Energy Strategy;* Consultation Document, June 2008. The UK emitted 557 million tonnes of CO_2 in 2006.

THE ECONOMICS OF RENEWABLE ENERGY 37

110. As wind generation increases, its capacity credit will tend to fall because low winds over part of the country can affect many wind turbines simultaneously. Extra, offsetting conventional plant is needed. The Renewable Energy Foundation's rule of thumb is to treat the square root of the wind capacity in GW as if it were conventional capacity (Q 112). On that basis, for example, 25 GW of installed wind generation capacity could be counted on for the same contribution to peak demand as 5 GW of conventional capacity; and it would take 36 GW of wind plant to match 6 GW of conventional plant.

111. Under any of these assumptions it is clear that much conventional capacity will be required to support renewable generators coming on stream in the period up to 2020, during which many of Britain's coal and nuclear power plants are scheduled to close. To replace them, the Government has calculated that 20–25 GW of new power stations will be needed by 2020—the equivalent of more than a quarter of today's 76 GW of electricity capacity. But that calculation assumes replacement on a like-for-like basis and does not take account of the target for renewables. **If some 30 GW of additional (Q 487) renewable capacity were required to meet the EU's 2020 target for the UK (and its capacity credit did not exceed 6 GW), a further 14–19 GW of new fossil fuel and nuclear capacity will still be needed to replace plants due to close and meet new demand. The total new installed electricity generating capacity required by 2020 would thus be roughly double the level needed if renewable generation were not expanded.**

112. The intermittent nature of wind turbines and some other renewable generators means they can replace only a little of the capacity of fossil fuel and nuclear power plants, if security of supply is to be maintained. **Investment in renewable generation capacity will therefore largely be in addition to, rather than a replacement for, the massive investment in fossil-**

fuel and nuclear plant required to replace the many power stations scheduled for closure by 2020. The scale and urgency of the investment required is formidable, as is the cost.

House of Lords pp 38

Storage—a permanent solution to intermittency
115. A sufficiently great advance in electricity storage technology would help solve many of the problems of intermittency (Q 98). If the storage could be charged and emptied quickly, this would be an attractive way of balancing the system. If the cost of storage capacity is sufficiently low, it would be an effective alternative to building additional generation capacity to deal with the peak levels of demand. The Royal Society of Edinburgh reported that a range of alternative storage technologies are being considered alongside the existing use of pumped storage hydroelectricity (p 453). Ofgem told us that fuel cells could become economically viable if their costs continued to fall, or electricity prices rose (p 171).
116. Dr Clarke of the Energy Technologies Institute told us more resources had recently been applied to developing energy storage, with major industrial corporations becoming involved. He pointed out that large-scale schemes might be located close to generators, and would then smooth out the load on the transmission system, reducing its costs. Small-scale storage could help to manage local demand. High-temperature batteries, mainly used by the military at present, are more efficient than conventional batteries, and could provide a significant opportunity where waste heat from combined heat and power schemes could keep them hot enough to work properly (QQ 318–20).
117. **A breakthrough in cost-effective electricity storage technology would help solve the problem of intermittency and remove a major stumbling block to wider use of renewable energy in the longer term. However, no evidence we received persuaded us that advances in storage technology would become available in time materially to affect the UK's generating requirements up to 2020. We recommend that the Government should as a matter of urgency encourage more research, development and demonstration in energy storage technologies."**

The House of Lords' inquiry is a seminal work on the issues associated with meeting renewable energy targets. The full report is attached as Appendix 1. Much of the observation and understanding that cuts through the rhetoric is directly applicable and translatable to the Queensland position appropriately modified for climatic differences.

A further observation of the intermittency issue is found in California where the enormity of proposition 7 is emerging even within the most hardened eco-innovators as demonstrated in the following excerpt.

"Would large-scale green power bust the budget?
Posted by Jamie On September - 14 - 2008

In a recent editorial, ECOworld.com presents some staggering figures for the cost of California's Proposition 7 (Prop.7) which, if approved, would require utilities to procure 50% of their power "from renewable resources by 2025."

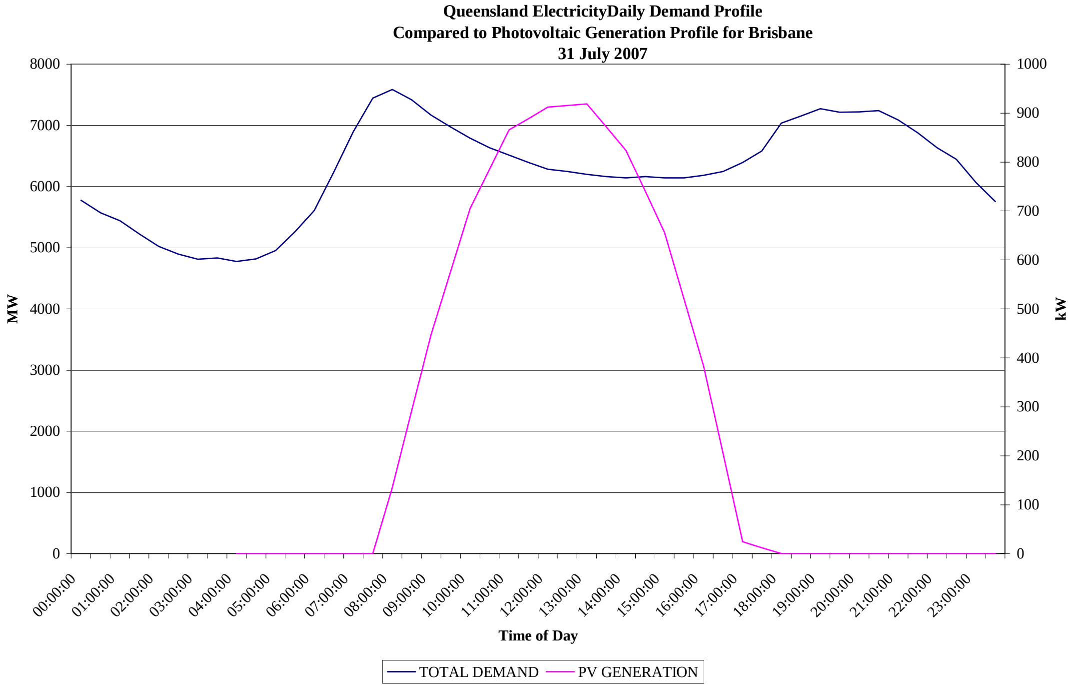
Compliance costs based on installation of wind generators (currently the most cost-effective renewable energy technology) are estimated at $300 billion. The cost for solar power is considerably higher.

In addition to the renewable generator installation costs, the utilities would also require approximately 100 gigawatt-hours of energy storage capacity to accommodate peak load. California's spectacular sunset is accompanied by calm winds and a rise in domestic activity as people power up their appliances and entertainment systems. Based on data from a large-scale electricity storage manufacturer, "the cost to load balance California's grid, should 50% of her energy come from solar or wind sources, would probably run about $35 billion dollars." This doesn't include property costs or transmission costs.

California's utilities are currently required to generate 25% of their power from renewables by 2025. A surprising opposition to Prop. 7 has emerged, with several environmental groups stating that it is "poorly written", could bring "unintended consequences", and may ultimately "slam the brakes on renewable energy development in the state."

Solar Bonus Scheme Effects

The Solar Bonus Scheme exacerbates the issue of intermittency and contributes to inefficiency of capital allocation through the need for increased reserve plant margin. The following graph plots the output of a typical photovoltaic roof-top system in Zone 3 (covering South-East Queensland against the daily demand for an equivalent day. This plot is based on data from the Australian Energy Market Operator.

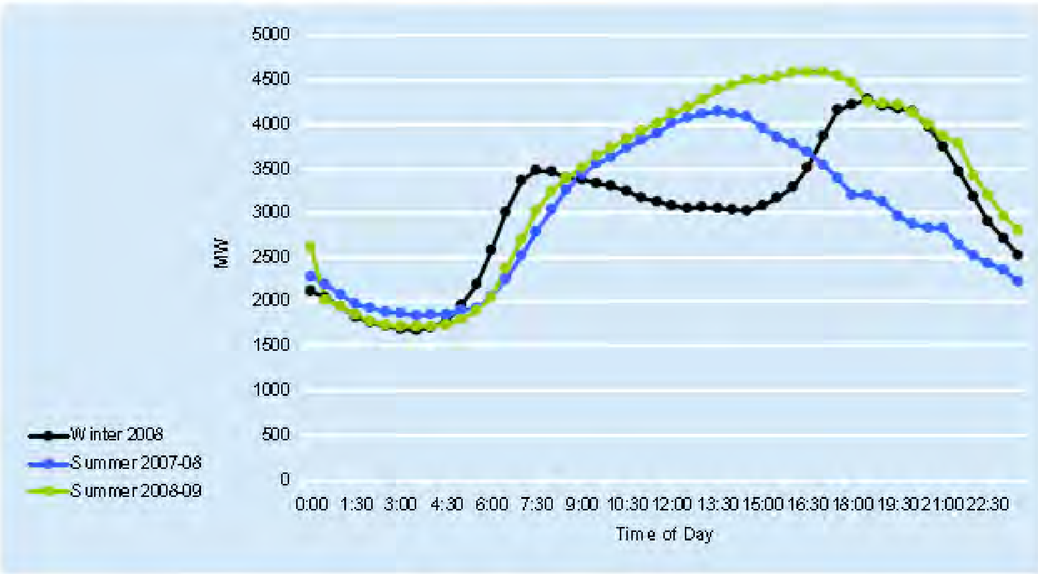


• Graph 1 - Daily load duration vs. PV Generation

This plot shows that the photovoltaic cell output does not coincide with the requirements for peak generation capacity and therefore does not contribute anything to the improvement of efficiency of the generation system; quite the contrary it exacerbates the efficiency of the generation system. The plot for PV Generation has been derive using PV Watts by the National Renewable Energy Laboratory (NREL), United States of America and data on Brisbane from the NASA database. The parameters used in PV Watts are set out in Appendix 2.

To avoid the charge of bias a daily demand plot produced by Energex is included below. Although the plot was produced for another purpose, it confirms that photovoltaic micro-generation will not eliminate peak generation needs to be serviced by other generation capacity.

Figure 5.3 ENERGEX's daily load profile



- Graph 2 - Energex Daily Load Curve

A Photovoltaic plot could not be overlaid on this graph because the data was not accessible. However, the time of day axis makes it easy to ascertain the general lack of coincidence of photovoltaic generation with peak demand.

It is quite apparent that there has been an insufficient depth of understanding of the issues when formulating renewable energy policy. This has lead to the situation where alternatives suited to the demands of the community such as geothermal power have had an artificial barrier erected by that policy formulation.

Feed in tariff policy

The Solar Bonus Scheme is what is generally termed, a net feed in tariff (FIT) that pays at the rate of $440 per MWh for excess electricity generation fed into the supply grid. The scheme only applies to generation by photovoltaic technology. With this limited application the policy automatically establishes a barrier for competing technologies.

Much has been made of the success of the German FIT and its success in promoting the photovoltaic industry in Germany as well as the successes of Spain and Italy. It is worth noting that in recent times those countries have recognised the massive cost to their economies of pursuing the FIT and scaled back considerably the action of the scheme. In Queensland, the FIT is much more narrowly defined and this aspect is even more deleterious due to the narrow focus of its application. Appendix 3 sets out the present schedule of German FIT. This table is included to show that the FIT is broadly based and covers the range of renewable technologies rather than trying to pick winners.

From an economic standpoint, the performance of Spain and Italy are nothing to write home about. Their profligate spending has placed those countries in the group euphemistically called the PIGS. This stands for Portugal, Italy, Greece and Spain. The common thread of this group is that they all have massive debt problems brought about by policies such as the FIT.

Whilst the debate rages amongst the economists who make simplifying assumptions to fit uncalibrated and empirically untested models to prosecute their case; any simple accountant can give one the correct advice that, except on a very small scale, FITs are unsustainable. This fact is well and truly established by the study conducted by the Rhur University which concluded in the abstract that: -

Abstract
The allure of an environmentally benign, abundant, and cost-effective energy source has led an increasing number of industrialized countries to back public financing of renewable energies. Germany's experience with renewable energy promotion is often cited as a model to be replicated elsewhere, being based on a combination of far reaching energy and environmental laws that stretch back nearly two decades. This paper critically reviews the current centerpiece of this effort, the Renewable Energy Sources Act (EEG), focusing on its costs and the associated implications for job creation and climate protection. We argue that German renewable energy policy, and in particular the adopted feed-in tariff scheme, has failed to harness the market incentives needed to ensure a viable and cost-effective introduction of renewable energies into the country's energy portfolio. To the contrary, the government's support mechanisms have in many respects subverted these incentives, resulting in massive expenditures that show little long-term promise for stimulating the economy, protecting the environment, or increasing energy security.
JEL Classification: Q28, Q42, Q48
Keywords: Energy policy, energy security, climate, employment
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The full report is contained in Appendix 4.

Further commentary on the German FIT experience is contained in Appendix 5.

There is ample evidence that the FIT policy of the Queensland Government establishes a very high barrier to entry for competing renewable energy technologies; is not cost effective and amounts to a massive cross subsidy to a small section of the community.

Question 3 Queensland Investments Performance

Commenting on investment performance in the absence of reliable information is difficult. The process of Government initiated grants and financial support mechanisms are non-transparent and not divulged voluntarily. In these circumstances the comments below are made from an external observation view point.

Investments and investment strategies (REP)

Q-REF Mackay Sugar $9 million

As explained in the REP

Renewable energy — diversifying the Mackay Sugar Cooperative

In the face of low sugar prices, Mackay Sugar successfully applied for $9 million from the Queensland Renewable Energy Fund to diversify into renewable energy production in the form of cogeneration and ethanol production. The cogeneration plant will provide 27 megawatts of renewable energy capacity to the Mackay district electricity grid for 50 weeks of the year, 30 per cent of the district's current usage and reduce greenhouse gas emissions by 200,000 tonnes per annum. At the same time it will provide steam and electricity for the sugar refinery and for ethanol production. The proposed 60 megalitre ethanol plant will derive all of its production steam and electricity from the cogeneration project, making it the 'greenest' ethanol produced in Australia. The project is significant in that unlike other bagasse cogeneration plants, it will be capable of supplying electricity in the crushing and non crushing season. During the non crushing season, the plant will be fuelled by stored bagasse.

Here is what a Mackay Sugar prospectus says about the cogeneration project.

Mackay Sugar Prospectus Closing 7 May 2010

Fuel supply

The cogeneration plant will be fuelled by Bagasse during the crushing season and for part of the non-crushing season. In a normal year there will be a surplus of Bagasse at Racecourse mill and additional tonnage of Bagasse which can be trucked from Mackay Sugar's other mills. It is expected that there will be sufficient Bagasse stored at the end of the crushing season to operate the cogeneration facility for approximately three months after the end of the crushing season.

When the Bagasse supplies have been depleted, the boiler will then be fuelled by coal. Coal is currently purchased from Blair Athol Coal Pty Ltd and Mackay Sugar is extending this contract to receive coal from Blair Athol Coal Pty Ltd's new Clermont mine in the future.

As far as investigations can ascertain there is no direct connection between the QREF funding and ethanol production. At this point it appears that an ethanol distillery may be implemented at some tine in the future when investigations are completed.

It is surprising that the cogeneration plant will be fired on coal for some part of the year. This was not disclosed in the REP and would appear to defeat the cause of the QREF funding aims.

QREF Birdsville geothermal $4.3 million

Reports and information on the Birdsville expansion is attached in Appendix 6.

It would appear that the project will cost $9 million funded 50% by the Government and 50% by a Government owned corporation. It is difficult to ascertain whether this sum represents an upgrade / replacement of the existing plant or an expansion. If it is a replacement to expenditure represents a cost of $112.5 million per MW of net output. If it is an expansion to 400kW gross, then in equivalent terms the cost is $32 million per MW net output. In both cases these are very large equivalent costs and the Inquiry should delve further into the business case that justified this level of expenditure.

Windorah concentrated photovoltaic $4.5 million

Material and information gathered is set out in Appendix 7.

It is difficult to establish from the literature any financial or performance results or outlook for this project. From an inspection of the installation the site-board claims typical output at 26kW per dish. There are 5 Dishes in the array but it seems that not all operate in unison. Assuming that the dishes will operate in unison, then the DC output would be 130KW. Allowing 10% for losses on DC to AC conversion one would expect a net output at battery limits of 117KW. This makes the capital cost of the installation $38.46 million per MW or $38.46 per watt. Considering that even the most expensive roof-top photovoltaic installations cost in the region of $12 per watt one could be forgiven for wondering what on earth is the justification for the exercise.

QREF Cloncurry concentrated solar thermal power $7 million of $31 million for 10MW

The status of this project is unclear. Appendix 8 contains the research carried out in compiling this paper. There is no financial information or business case available supporting this project. Furthermore it is unclear on the circumstances in which the project garnered Government support.

Historically Lloyd Energy Systems had an experimental installation at Cooma, NSW. This was backed by interests associated with the, now defunct Alco Finance. Photos of this installation are included with the Appendix material. At the time these photographs were taken in January 2008, the installation was in a state of total disrepair and non-operational. It is unclear whether any useful data collection ever occurred or whether the graphite storage concept ever performed.

The project at Cloncurry seems to be headed for the same fate. Apparently, despite all of the protestations nothing seems to be happening.

QREF Geothermal centre of excellence QUT $15 million

Material concerning the Geothermal Centre of Excellence is contained in Appendix 9. From the web-site and Government announcements it is unclear as to the objectives or the deliverables of this research institution. Various announcements have been made but the status of the proposed studies is not followed up. There are grave doubts about the material physics and chemistry of the proposed super critical geothermal siphon. There would be great interest to see the idea defeat the basic principles standing in its way. Again, the adaptability of geochemical techniques to assessing and measuring energy physics seems like searching for the Holy Grail. It will be fascinating to observe the progress.

QREF Government coastal geothermal drilling programme $5 million

The programme outline for the coastal geothermal drilling programme is set out in Appendix 10. The intent of this programme is to establish whether there is any geothermal prospectivity in the vicinity of existing electricity transmission systems. The proposal is to:-

- Identify areas in eastern Queensland where collecting additional temperature and heat flow data sets is required
- Collect new data by drilling specific wells and through liaison with industry
- Improve geophysical coverage of coastal areas where required

- Provide an enhanced assessment of geothermal resource potential in eastern Queensland.

The map in the appendix identifies 38 possible sites for: -

- Fully cored HQ size boreholes from below unconsolidated formations to nominal depth of 300–320 m
- Temperature and additional petro physical data from geophysical down-hole logging
- Well log interpretation and core logging
- Collection of core samples for analysis of thermal conductivity property.

The identified locations already have a vast amount of data at the depths contemplated by this programme. These data can be derived from drilling results of coal exploration activities, water bores and petroleum drilling operations. There is a substantial body of work that establishes without doubt the vast geothermal potential of Queensland over more than a third of the state. The statement in the proposal that: -

> Queensland's known geothermal resources are in the far south-west of the state, a long way from the existing electricity transmission lines and major population centres;

is a gross misstatement of fact that is amply demonstrated in the map contained in the proposal document. The map shows the temperature at depth derived from, but not attributed to, Geoscience Australia. It is entitled "Projected Crustal temperature at 5 km depth (Austherm 04)". The temperature mapping extends under the entire Great Artesian Basin covering in excess of a third of Queensland.

The fact that Geoscience Australia does not attribute geothermal potential in the vast majority of the area identified for expenditure must give a guide as to the likelihood of the outcome.

In respect of the claims about transmission distance, CEA has geothermal tenements within 7 km of adequate transmission lines.

QREF Wind mapping program $0.25 million

There is no real information on this programme.

QREF Townsville solar cities contribution $5 million of $30 million for 0.5MW

As for other projects in the solar sphere the sums just don't seem to add up. $30 million for 0.5MW equates to $60 million per MW or $60 per watt. As stated before even the most expensive roof-top solar installation would cost $12 per watt; why does this programme cost 5 times more?

About the QREF

There has been much talk about renewable energy in Queensland over a long period of time. The Queensland Renewable Energy Fund (QREF) was announced in February 2008. The purpose of QREF is to quote the climate smart 2050 paper: -

"Queensland Renewable Energy

Fund (QREF)

The QREF is a $50 million investment by the Queensland Government to take renewable energy technologies from demonstration stage to deployment.

The funding program supports the development and deployment of renewable energy generation technologies in Queensland that are beyond proof of concept. The QREF will provide concessional loans for up to 100 percent of the project's value or as a grant of up to 50 per cent of the project's capital value. Funding is being allocated through annual funding rounds."

So far as we are aware only one round has ever been called and that closed at 4:00PM on 26th May 2008.

Solar hot water program

$1000 pensioners; $600 all others eligible for 20 RECs

Insufficient data are available or disclosed adequately to comment on this programme. However from a theoretical point of view this programme has much to recommend it. The heating of water implicitly creates a mechanism for storing energy. Moreover this storage is created at the point of consumption. As a consequence it gives "the biggest bang for the buck" in terms of efficiency of capital and demand on electricity facilities. As stated earlier this programme should be amended to expand it to replacement of all hot water systems using fossil fuels.

Multiple small scale solar-thermal plants for regional Queensland (no cost assigned)

Lack of data and information prevents commentary on this programme.

Large scale solar thermal investigations in partnership with the Clinton foundation (no costs assigned)

Lack of data information objectives or reports prevents commentary on this programme.

Geothermal pilot by 2014 (no costs assigned)

There is no basis for projecting a geothermal pilot project as late as 2014 except if it is the Government's intention to delay projects. Projects are ready for implementation immediately. However, they have been beset by the barriers to entry set out earlier in this paper. More detail is given later in this document.

Small scale photovoltaic for isolated communities (no costs assigned)

It is presumed that the Windorah project is an example of this initiative and this is discussed elsewhere in this paper.

Government owned generators partnering with industry to identify renewable energy solutions (no costs assigned)

The action on this programme is not self evident. It would seem that most of the projects pursued by the Government owned corporations are either internal or between the GOCs and the Government. In fact, looking at the evidence it would appear that the Government is averse to providing any assistance or support to industry outside of the solar sphere.

Demand side management and master planning (no costs assigned)

There are two aspects to demand side management. One aspect is with respect to ensuring that appliances are efficient. That adequate regulation is essential for this aspect to be achieved is self evident.

Solar bonus scheme net metering bonus (no public information)

No data or reports are available of disclosed on this programme. However, the issue of feed in tariffs is discussed elsewhere in this document.

Solar schools scheme $60 million for 2kW systems in 1250 schools (no costs or savings assigned)

This programme envisages a cost of $24 per watt for installations similar to the federally supported solar homes and communities programme. Although the sentiment of solar in schools in unarguable, one must question why it is twice as expensive as the most expensive solar panel installation available today?

Question 4 Priority Issues for Investment

1. Extend solar hot water rebate to natural gas installations
2. Target Technologies.

   Identify and target technologies that match the way in which the community uses its energy. This is particularly essential with respect to the intermittence issue address in this paper.
3. Maximise Efficiency.

   Ensure that efficiency maximising practices are adopted by retailers of electricity consuming appliances through appropriate standards and regulation
4. Maximise Employment

   This is best accomplished by assisting industries developing in Australia. The present Solar and Wind assistance exports more jobs than it creates locally. This could be ameliorated by requiring a certain local content. However the best decisions are to assist industries where Australia has an advantage.
5. Maximise Industry Development

   Adopting approaches to maximise employment will provide a natural flow-on to this aspect of the renewable business.
6. Avoid Boom and Bust Cycles

   Policy decisions in Government are littered with the bones of boom and bust cycles. The Home Insulation Programme is a case in point. Not only was this programme exacerbated by poor execution but the industry was sure to come to an abrupt end when the programme had fulfilled its objective anyway. There simply is not an after-sales market in the nature of the business.

   The Spanish solar FIT is another. The industry has come to a crashing halt following cuts in the over-generous FIT.
7. Expand the Technology Portfolio.

   Ensure a portfolio of technologies and opportunities can flourish
8. Set Transparent Research Goals and Objectives

   Research grants should be treated no differently than any other recipient when it comes to dealing out public funds. Research grants should be required to set measurable achievement indices and milestones; and to identify objectives that can be adequately scrutinised.

Question 5 State Renewable Energy Targets

1. Remove Coverage Limited to Electricity
2. State Targets

   Targets should be set for overall energy consumption with a subset for electricity based on its forecast share of the total. If all sources have the same incentive then the cheapest alternative will take the largest share.

Question 6 Target and Form (Scope) of State Targets

1. Quantum

   The State's net consumption of energy in all its forms in the latest Australian Bureau of Agriculture and Resource Economics (ABARE) in the year 2007/08 was 1336PJ, equivalent to 371,100GWh. A reasonable target, commensurate with European standards would be 20% of that figure making the target 267PJ or approximately 74,000 GWh.

2. Objectives

   There are two aspects to the concept of renewable energy that are mixed up and obfuscated by the debaters vis: -

   i. Removing energy supply reliance on fossil fuels; and

   ii. Reducing green house gas emissions caused by energy consumption.

   It should be policy intent to pursue the achievement of both objectives in priority to achieving only one or the other.

3. Examine the Technologies Against Objectives

   The REP encompasses a number of technologies for renewable energy electricity generation vis: -

   i. Biomass 645MW

   ii. Solar photovoltaic 40MW

   iii. Solar thermal 250MW

   iv. Hydro 200MW

   v. Geothermal 250MW

   vi. Wind 750MW

   vii. Solar hot water (demand management by substitution) 500MW

   Total requirement by 2020 is 2635MW

   The REP is devoid of any information as to how this energy mix is derived, the relative costs of getting there or how the plan fits with the characteristics of the Queensland electricity system.

   Lets us examine the conclusions. Appendix 11 sets out the Scheduled, semi-scheduled and non-scheduled generation capacity of Queensland connected to the national electricity market (NEM)

   Biomass

   The REP identifies that 25% of the renewable energy should be sourced from Biomass. From Appendix 11 the principle fuels for biomass generation in Queensland are bagasse and wood waste.

   Bagasse is waste from sugar cane processing and electricity generation is derived from co-generation using the bagasse during the process of processing and refining sugar. In and of itself, this generation is dependent on sugar processing. As a consequence it will always be a by-product that cannot be reliably dispatched in accord with the demands of the electricity consuming community. Furthermore, it is seasonal and other generation needs to be on standby for deployment when this generation source is unavailable.

   Energy production from biomass sources simply recycles carbon and does not contribute to green house gas reduction or abatement. Moreover, it is a by-product and commercial to pursue in the present economic climate.

The consequences of these facts are that the availability of biomass generated electricity sources will be dependent on the progress of the industries it relies on. No amount of planning or assistance will alter the rate at which it develops.

The growth of the ethanol fuel industry presently subsidised through federal subsidies is likely to cause an increase in generation from bagasse. However, when the ethanol production process is examined closely, it is easy to come to the conclusion that the industry will consume more electricity than it produces.

Biomass generation achieves the objective of producing electricity from renewable fuel sources. However, it does not contribute directly to green-house gas abatement.

Solar photovoltaic

Solar photovoltaic electricity generation fulfils both of the objectives of renewable electricity generation.

Solar Thermal

Solar thermal electricity generation fulfils both of the objectives of renewable electricity generation.

Hydro

Hydro-electric generation fulfils both objectives of renewable electricity generation

Geothermal

Geothermal electricity generation fulfils both objectives of renewable electricity generation

Wind

Wind turbines accomplish both objectives of renewable electricity generation.

4. Examine the Constraints

   Dispatch

   Hydro-electricity and Geothermal electricity can be dispatched with Hydro being constrained by its storage capacity.

   Intermittency issues need to be thoroughly understood because they detract from the quality of supply to the consumer.

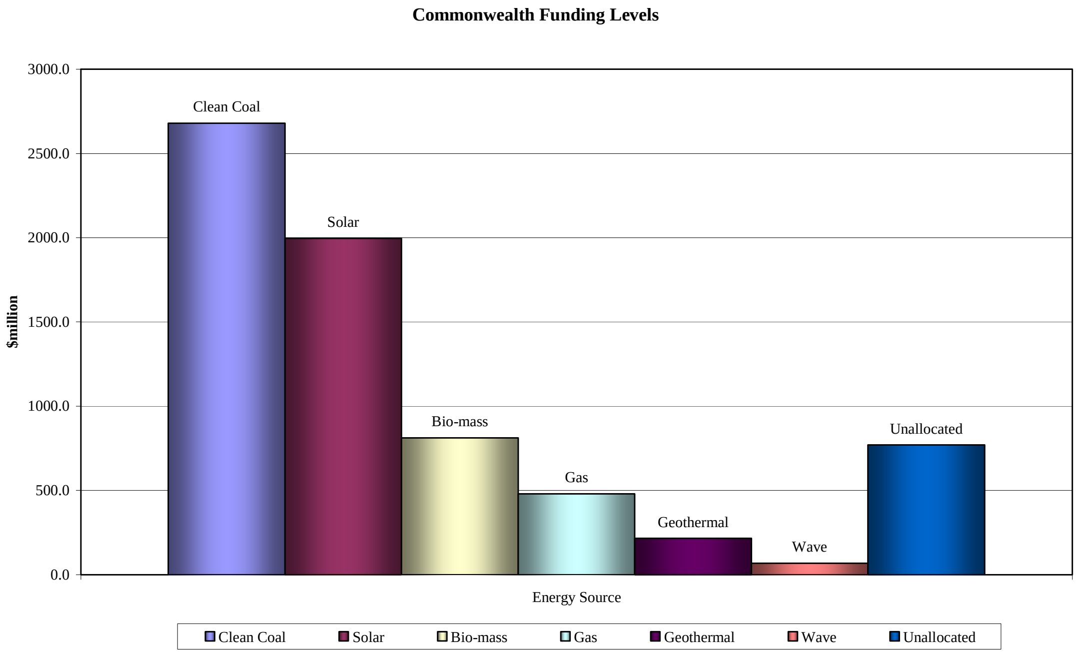
Distributed generation in remoter regions.

Renewable Energy Drivers

The law requires that Australia achieve 20% of its electricity from renewable sources on a schedule accumulating to 45000 GWh by 2020 (20% RET).

Besides this requirement a number of initiatives have been implemented generally with the intent to reduce emissions of carbon dioxide from fossil fuel combustion. We will only concern ourselves here with those directly connected with the 20% RET.

Australian Government programs directed to the 20% RET totalling $5.1 billion together with previously committed programs are set in graphical form below showing their allocation by energy source.



- Graph 3: Source Budget papers, Program Announcements, Expenditure Statements

Issues with the Competing Technologies and Energy Sources

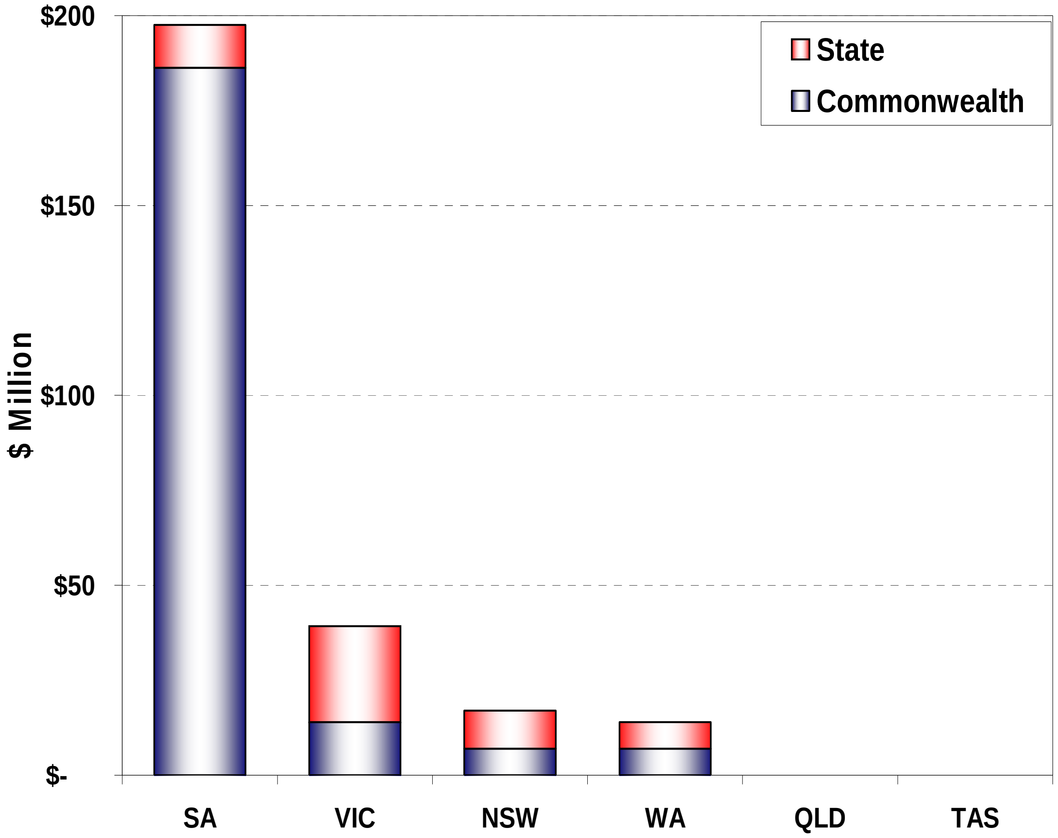
Clean coal is a synonym for carbon capture and storage (CCS). A prognosis for the science is not promising (see Flannery attached in CD) and proving time frames are being prolonged; moreover, financial conditions have caused at least one major project to be suspended. Internationally, CCS projects are receiving far less, Government policy related, financial support because of the dawning realisation that it is not financially competitive. Implementation of any commercial scale CCS could not feasibly be accomplished in the 20% RET time-scale.

Solar, wind and wave energy sources all suffer from the intermittent nature of the supply source. A consequence of this quality is that standby alternatives need to be in place or some form of energy storage is required to support this intermittency. More often than not the cost of this additional support need is not taken to account by the proponents. In relation to Solar and Wind sources, both are affected by climate and this adds the dimension of unpredictability into the degree of difficulty equation. A recent example of this occurred in Adelaide during a heat wave when no wind energy was available and the wind farms failed to deliver against a high air-conditioning load.

Geothermal energy has been successfully harvested throughout the world for over one hundred years. The technologies are available and proven. There is five times more electricity production from geothermal energy than all of the solar electricity systems (photovoltaic and concentrated solar power) combined. Moreover this production is not subsidised. Geothermal electricity production is a proven base load source and has load following capabilities over a broader operating range that any base load system in operation today. The issue with geothermal energy is that the process needs to be translated to local conditions and this needs Government assistance in the initial phases. The promise is lower risk and higher community return.

Geothermal Industry Development Policy and Assistance

Within the allocation of Australian Government funds to geothermal the distribution between mainland States and additional support by State Governments is set out in the Graph below. It will be quite apparent from this graph that Commonwealth Government policy has skewed the establishment of the emerging geothermal industry geothermal industry towards one State in particular. Furthermore, Queensland, a State in which the Government's own scientific advice predicts a high level of prospectivity, has received no support from the Commonwealth Government.



- Graph 4: Relative Commonwealth and State Geothermal Support

Trends in Electricity Pricing

Electricity retailing is transferring from public to private ownership as Governments sell off utility assets to balance budgets.

Increasingly, the new retailer ownership is trying to move customers out from under the safety net of regulated tariffs to unregulated contracts

The lack of depth in the market means that competition exists in theory only; and this competition is a small margin of the total tariff.

A major portion of electricity tariffs comprise transmission and distribution that are controlled and regulated by the Australian Energy Market Operator and the Australian Energy Regulator. These bodies function in the bowels of the wholesale market system remote from the consumer, and Government oversight and responsibility. As a consequence the process of adjusting tariffs tends to be "clubby" between the regulators and the large wholesale market participants. The process also is obfuscated by complexity. The loser, the consumer is not properly represented at the table.

The uniform tariff policy that exists in Queensland and other States is coming under increasing political and economic pressure by the "rationalists" in order to balance budgets by removing community service obligations. The economically rational argument is for the removal of cross subsidies. By avoiding the social objectives this argument is shallow in the extreme. However, the low vote weighting of beneficiaries curries favour with the political strategists.

Regulated Retail Pricing Decisions

The table below shows recent regulated pricing decisions affecting domestic and small business tariffs. The trend is much larger than the underlying inflation, expected demand growth and forecast population growth. This suggests a systemic failure of the regulatory system.

- Table 1: Regulated Electricity Price Trends

Electricity Price Trends - Regulated Prices				
	Incr.	Incr.	Incr.	Incr.
	2009/10	2010/11	2011/12	2012/13
IPART - NSW				
Country Energy	20.20%	12.40%	16.80%	23.20%
Energy Australia	22.50%	9.60%	15.60%	24.60%
Integral energy	20.90%	6.50%	14%	18.70%
	2009/10	2010/11	2011/12	2012/13
QCA - QLD				
BRCI	11.82%	13.29%		
Energex	11.82%	13.29%		
Ergon	11.82%	13.29%		

Trends in Electricity Markets and Regulation

The setting up of regulatory bodies has acted to divorce regulation from political responsibility. As a consequence, less than adequate oversight becomes “nobody’s fault”.

Centralised regulation through the Australian Energy Market Operator and the Australian Energy Regulator is remote from the constituents these bodies are supposed to protect.

Policy in connection with energy is increasingly controlled from Canberra through the Ministerial Council on Energy. The States effectively have ceded their energy resources to Canberra.

With the regulatory bodies remote from the “coal face” there is a tendency towards a “one size fits all” regulatory regime; and inaccessibility for the constituents.

This regulatory style has lead to complication and obfuscation by experts where decisions are based on opinion escalated by opinion at each review when, in fact, real costs are observable.

Uniform Tariff Policy – Headed for Extinction?

Queensland’s uniform tariff policy together with like-minded States is under review by the Ministerial council on Energy under the guise of establishing a national framework.

When these activities take place, inevitably some “tinkering” occurs to the detriment of the recipients irrespective of the social justification.

In financial year 2008-09 electricity community service obligation payments cost the budget in Queensland $450 million. Considering the State of Queensland finances one could expect such payments to be under considerable pressure for elimination.

Trends in the Cost of Electricity Supply

The main cost functions in electricity supply are: -

Fuel and generation that is overseen by the Australian Electricity market Operator and the Australian Energy Regulator

Transmission and Distribution, again overseen by the same bodies; and

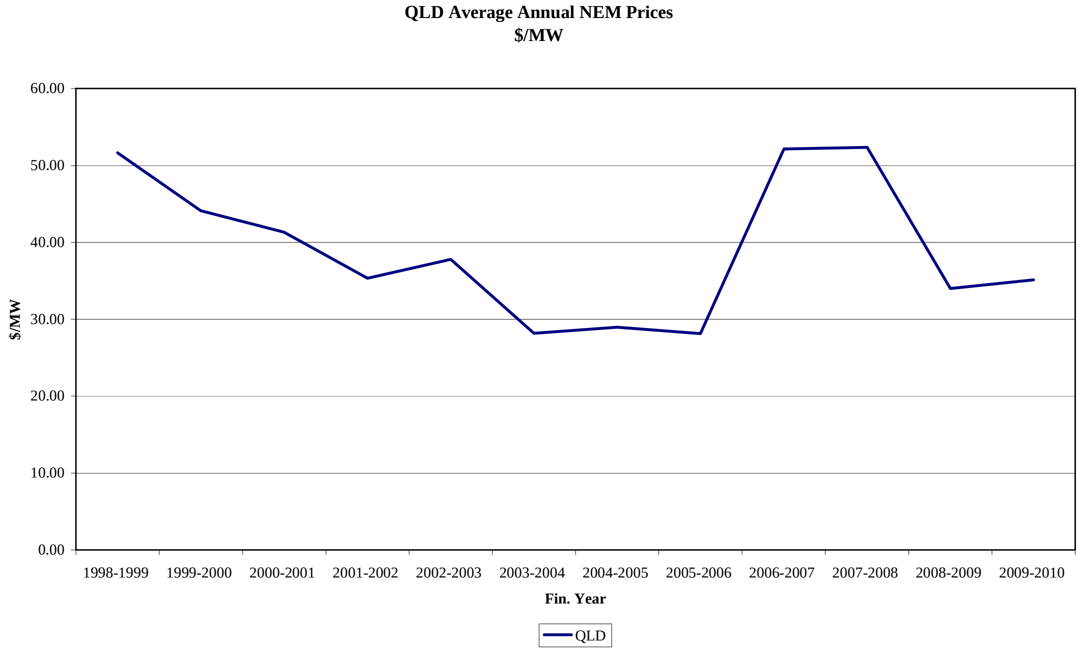
Retailing and customer billing that is overseen by the Queensland Competition Authority (QCA) in Queensland.

The QCA as the retail regulator passes through the ruling of the AER in arriving at a retail tariff decision.

Fuel and Generation

Historically average annual fuel costs and generation cost has varied up and down with demand as demonstrated by the wholesale National Electricity Market (NEM). However, the true wholesale cost of electricity is masked by substantial non-transparent derivative contracts between generators, wholesalers, and retailers.

The graph below shows the annual average NEM price for the years 1998-99 to 2009-10 (up to May). In this period, at no time has a decline in wholesale electricity price been matched by a reduction in tariffs. The most likely explanation is that the NEM is not a transparent representative market.



- Graph 5: NEM annual average prices

This observation on the NEM in reinforced by the disparity between NEM prices and QCA derived energy cost used in establishing the benchmark retail cost index BRCI for annual tariff determination that is based on a combination of long run marginal cost (LRMC) and AER determined purchase cost. The table below reflects the distinction.

■ Table 2: NEM wholesale electricity price vs. QCA benchmark cost

	NEM Price $/MW	QCA BRCI $/MW
2008-09	$34.00	$54.70
2009-10	$35.12	$61.20
2010-11	N/A	$66.60

Network Transmission and Distribution

Network transmission and distribution is the largest component in the cost of electricity and is growing at a much greater rate than the other major components. In the last year in Queensland it has grown by 17.4%.

This trend makes it an increasing proportion of the electricity price over time.

When examined in detail in the submissions to the AER for the five year period the propositions seem incomprehensible as can be assessed from the following parameters from the Ergon decision: -

■ Table 3: Ergon cost parameters AER determination

Regulated Asset Base brought forward	$7148.9 million
Forecast Capital Expenditure ($2010)	$4988.9 million
Capital expenditure increase (real)	69.8%
Increase in consumption	15.9%
Revenue Growth	34.2%
CPI	13.25%
Maximum Demand growth	18.2%
Growth in Customer numbers	8.3%

It is clear from the process that continuing increases in capital expenditure drive revenue and profits and motivates utility management in that direction.

Network transmission and distribution charges are the main determinant in CSO payments to the distribution service providers.

The table below shows this drift to increasing transmission and distribution components in the electricity price.

■ Table 4: Changes in QCA electricity cost components

BRCI cost component	***2008-09***		***2009/10***		***2010/11***	
	$/MWh	***Share of Total***	***$/MWh***	***Share of Total***	***$/MWh***	***Share of Total***
Cost of Energy	54.70	44.11%	59.95	43.65%	65.17	41.89%
Network costs	57.50	46.37%	64.63	47.06%	75.90	48.78%
Retail costs	11.80	9.52%	12.76	9.29%	14.52	9.33%
Total	124.00	100.00	137.33	100.00	155.59	100.00

Retailing

Retailing represents less than 10% of the electricity price.

Retailing generally is tied to other costs and will fluctuate with them. However, the cost of keeping customers is a function of competition which would feed on itself if all retailers received recognition for this cost. To the extent that this is an allowable claim in the present QCA determinations, that process is flawed.

Retailing is subject to a fixed profit margin on costs for regulated tariffs.

It appears that retail tariff components are based on forecasts with no adjustment for errors in past forecasts. This would appear to be a flaw in the process.

Outlook for Decentralised Queensland

Decentralised or regional Queensland risks disproportionate increases in electricity prices because of: -

Increasing costs of transmission and distribution in the electricity pricing mix;

Substantial budgetary pressures on CSOs;

A price indexing method that does not feed back experience into the price adjustment process; and

Reduced political weighting and the application of rational economics.

Courses of Action and their Issues

One course of action obviously is to do nothing. This rarely leads to a beneficial outcome and runs the risk of depreciating the value of regional Queensland.

Another course of action is to lobby for greater financial support in CSOs and rebates to defray any rises in costs. This course has been successful in the past and is what has lead to the uniform tariff policy. However, the political climate has changed and course of action is likely to be less successful in the present climate.

A third course of action is to take control and responsibility for local electricity generation. Again this undertaking is not new; and was the norm prior to grid connection for many regional settlements. In order to foster generation locally, it must be shown to be competitive with the alternative of the do nothing case.

Local Generation Possibilities and their Issues

The range of available energy sources and technologies dictate the possibilities for local generation and distribution. These generation possibilities are examined here in more detail.

Coal based Generation
Although a possibility, a suitable deposit is not presently available. Diseconomies of scale, environmental and regulatory constraints make coal a non-feasible solution at the local generation level.

Diesel Generation
Diesel has been used in the past. However the price of fuel was one of the prime reasons for its replacement with grid connection in many regional towns. Since that time the relative price of diesel fuel has moved this source further into the uncompetitive sector.

Gas
Natural gas requires substantial distribution infrastructure to reticulate the RAPAD region. This factor together with a shift in gas pricing to export parity with LNG developments places gas in the uncompetitive realm with diesel. Moreover, the gas component of grid connected electricity is increasing with gas fired installations so importing gas for smaller scale generation works against itself.

Wind Power
Wind power generation has been utilised successfully in a grid system with a mix of generation types. It is opportunity generation at its barest incarnation. It is only available when the wind blows at speeds preferably greater than six metres per second or 22kmh. Being subject to the vagaries of the weather, there are issues of reliability, predictability and providing back-up. When solutions to these issues are factored into a remote of non-grid connected system this alternative is rendered uneconomic and uncompetitive.

Solar Photovoltaic and/or Concentrated Solar Power
The characteristics of the solar energy source are similar to wind power with the exception that it is highly predictable. It is, however diurnal and therefore cyclical. As a consequence energy storage is necessary when it is not available. When this storage requirement is factored in power costs rapidly approach the uncompetitive sector. Being a climatic energy source solar also is subject to the influences of seasonality, prevailing weather conditions and climate related equipment damage. All these contingencies require back-up support from either redundant equipment or grid connection.

The need for grid connection effectively halves the attainable capacity factor with attendant effects on the commerciality and competitiveness of the supply.

Geothermal Electricity Generation
Geothermal electricity generation has proven capable of operating stand-alone reliably in base load situations elsewhere in the world. This fact is well chronicled. For a well researched scientific review see Lawrence Livermore Laboratories at: -

http://www.uctv.tv/search-details.aspx?showID=15238

Warning this is a 45 minute presentation.

Geothermal energy has the same desirable characteristics as the other renewable energy (solar, wind, tidal and biomass). They have zero net emission of green-house gas, zero or minimal fuel cost and renewable. However, it is devoid of the undesirable characteristics of unreliability, climatic influence and cyclicality.

All this seems ideal. However, it must be said that the effectiveness of geothermal power generation is dependent on the geological setting in which it is deployed. Accordingly there is a need to prove the deployment by risking some investment to establish its technical competence. This risk investment can be minimised by employing slim-hole petroleum exploration techniques and small scale test facilities. Once this proof of concept is accomplished, there is no known impediment to scaling up the development to any size.

5. Look at the Costs

Very little attention seems to have been given to comparing the cost of various renewable energy sources and their resulting electricity prices. The table below shows comparisons by reputable independent organisations for the United States situation. Although the Australian translation may be somewhat different, the relativities can be expected to be similar.

- Table 5 - Levelised Costs of Energy

	CPUC	Lazard Range		Credit Suisse Range		
Comparative Levelised Electricity Generation Costs $/MWh	W/o Tax incentives	Lower	Upper	Lower	Base	Upper
Biogas	116.39					
Landfill Gas		50	81			
Biomass	181.46	50	94			
Biomass co-firing		3	37			
Geothermal	118.93	42	69	22	36	60
Hydro-small	121.95					
Solar Thermal	180.78	90	145	69	90	126
Solar Photo Voltaic - Crystalline		109	154	119	163	201
Solar Photo Voltaic - Thin film		79	124	109	140	180
Wind	133.73	44	91	30	43	61
Energy Efficiency		0	50	0	15	30
Fuel Cell		115	125	72	90	117
Coal IGCC	115.27					
Coal IGCC with Carbon Capture & Storage	173.94	104	134			
Coal steam turbine	105.94	74	135	46	55	66
Gas Combined Cycle Combustion Turbine	93.94	73	100	40	51	64
Gas Combustion Turbine (open cycle)	503.54	221	334			
Hydro Large	121.95					
Nuclear	153.91	98	126	35	62	64
<5MW Combined Heat & Power	209.21					
>5MW Combined Heat & Power	127.4					
CPUC = California Public Utilities Commission						
Lazard =Lazard Report - Levelised Cost of Energy - June 2008						
Credit Suisse = Sector Review - Alternative Energy 2 January 28 2009						

Question 7 Government Incentives for Renewable Energy Generation

- Feed in Tariffs

Discussions earlier in this document have demonstrated the pitfalls of ill conceived and badly crafted FITs. No doubt FITs can work if properly crafted. One essential element in any FIT is that it should be neutral and non-discriminatory as between renewable energy alternatives. There are perverse interactions between FITs and emissions trading carbon pricing.

- Rebates

It is difficult to avoid discrimination between renewable energy sources and types. In most circumstances they turn out to be a cross subsidy that stifles competition, eliminates innovation and maintains the status quo.

- Bounties

Bounties in the form of exploration drilling subsidies were extremely successful in establishing the petroleum industry in Australia in the late fifties early sixties. A similar approach could be pursued for developing renewable energy sources e.g. geothermal exploration drilling subsidy

- Grants

Grants are best utilised in basic research or where bounties become impractical. However grants should be carefully examined and require the recipients to have a proper business case, objective, milestones and a high probability of a commercial outcome.

About Clean Energy Australasia

Who is Clean Energy Australasia Pty Ltd

- Clean Energy Australasia Pty Ltd (CEA) was formed in November 2006 to acquire and develop geothermal zero emission energy sources.
- CEA's members and substantial shareholders comprise energy professionals and geo-scientists with more that 250 years of combined experience in energy and geo-technical disciplines.
- Dominant professional experience – Petroleum Industry – all disciplines

What are Our Energy Assets

- CEA holds 32 geothermal exploration tenements covering 17,000 square kilometres in the most prospective locations in Australia in Queensland and South Australia. The attached map shows geothermal temperatures at 5 kilometres overlain with CEA's licences.
- CEA's licence areas are coincident with very high levels of solar energy availability.
- Each geothermal tenement is estimated to have long term capacity in excess of 500MW of base load power. The potential for zero emission geothermal electricity production is large. Present annual consumption within the NEMMCO system is ~200,000 Giga-watt hours. CEA's leases could meet this demand on geothermal production alone for in excess of 100 years.

What are Our Markets and Projects

- CEA has identified a number of prospective markets for geothermal electricity production at an early date: The NWQ Minerals Province (Mt Isa / Cannington mines) – 500MW potential, Longreach / Winton / Barcaldine – 25MW initial and Moomba area petroleum operations and potential CO2 geosequestration – 25MW initially.
- CEA is progressing a number of projects in a phased pilot development aimed at establishing the commercial viability of geothermal electricity production at an early date.
- The programme comprises: -
  - The drilling of slim-hole geothermal exploration wells proximal to the NWQ Minerals Province (EPG11) and Longreach (EPG37)
  - Initial geothermal proof-of-concept pilot developments of ranging from about 50-100kW to about 1-2MW generation capacity.
  - Phased scaling of projects to demonstrate commercial viability.
  - Moomba SA area (GEL273) and Ballera Qld (EPG52), subsequent investigations into the use of carbon dioxide as the energy transfer fluid. Carbon dioxide is available locally from petroleum recovery operations and this phase has a geo-sequestration element in its direction (see attached Cooper Basin map)
  - Solar-thermal boosting option of fluid energy levels for improved energy efficiency and incremental power generation.
- CEA's geothermal programme involves the adaptation of existing proven technologies employed in the petroleum industry. A low risk and low cost approach – well depths of 3-4km and temperatures of 150-200^{o}C. Solar superheating option to increase temperatures to 250-300^{o}C.
- CEA's levelised long run electricity costs are estimated at $50-70/MWh
- The project tenements EPG11-15 (Mt Isa) and EPG37 and 90 (Longreach), EPG53 (Winton) are located within easy access to growing electricity markets and /or

transmissions systems allowing unhindered commercialisation. GEL273 (Moomba) and EPG52 (Ballera, Qld) provides significant power generation and CO_2 geo-sequestration potential (see infrastructure maps attached).

- For more information please see http://www.cleanenergyaus.com.au

How Can Others be Involved

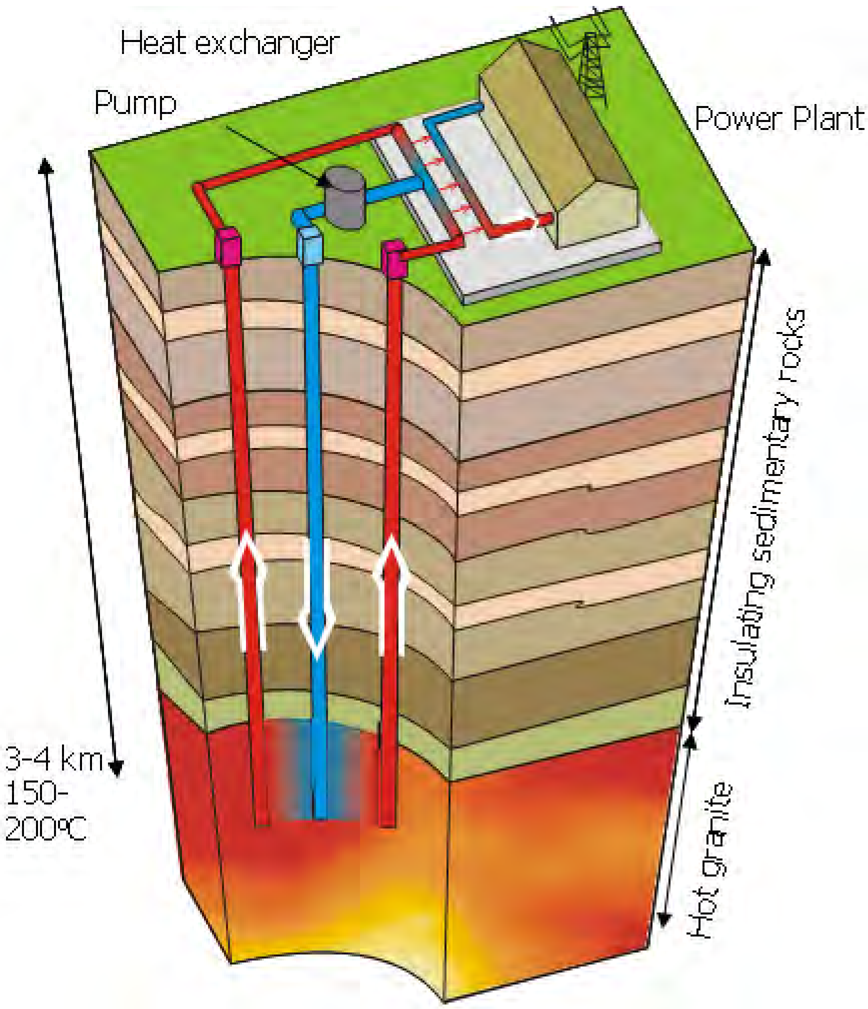
- CEA's business model is to collaborate with other organisations that have complementary skills and experience;
- CEA's skill-set is in geotechnical development, operation and commercialisation;
- CEA recognises that it needs to collaborate and / or joint venture with organisations with electricity generation, transmission, distribution and marketing skill-sets;
- Involvement mechanisms are not specific and will be structured to suit the business constraints of interested parties; however CEA is very familiar and comfortable with joint venture structures;
- It is recognised that potential participants have differing appetites for commitments in an environment of technical risk. This situation can be accommodated by adopting a phased approach to financial commitments that matches the progress of project implementation and risk reduction by way of an option structure.
- Underlying the flexibility of approach to participation is the basic premise that participation in a tenement is set at the outset at up to 50% interest in tenement expenditure contribution.

What are the Benefits

- Ultimately it is expected that the commercialisation will result in market entry of electricity with zero emission status;
- Participants will benefit in proportion to their participating interest in the privileges accorded to zero emission electricity generation by the law and government regulation.
- For some participants, it will be an entre to new and diversified markets;
- In initial participation, whether by option of farm-in, participants will gain access and insight into new and emerging technology

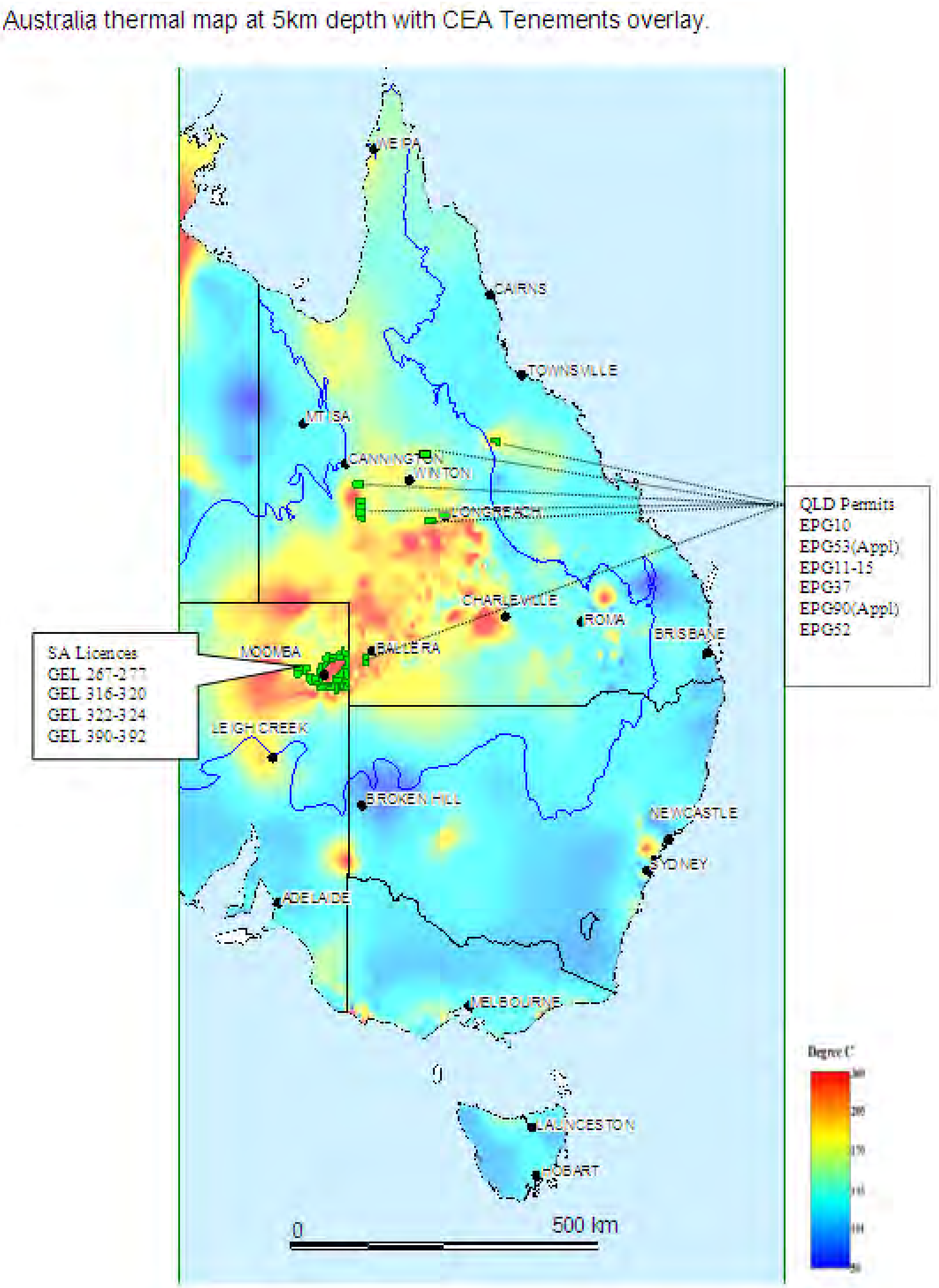
Geothermal Power

- Water pumped into injection well
- Circulated through fractured hot rocks in sub-surface
- Super-heated water / steam is then returned to the surface through production well
- Super-heated water / steam is used to generate electricity



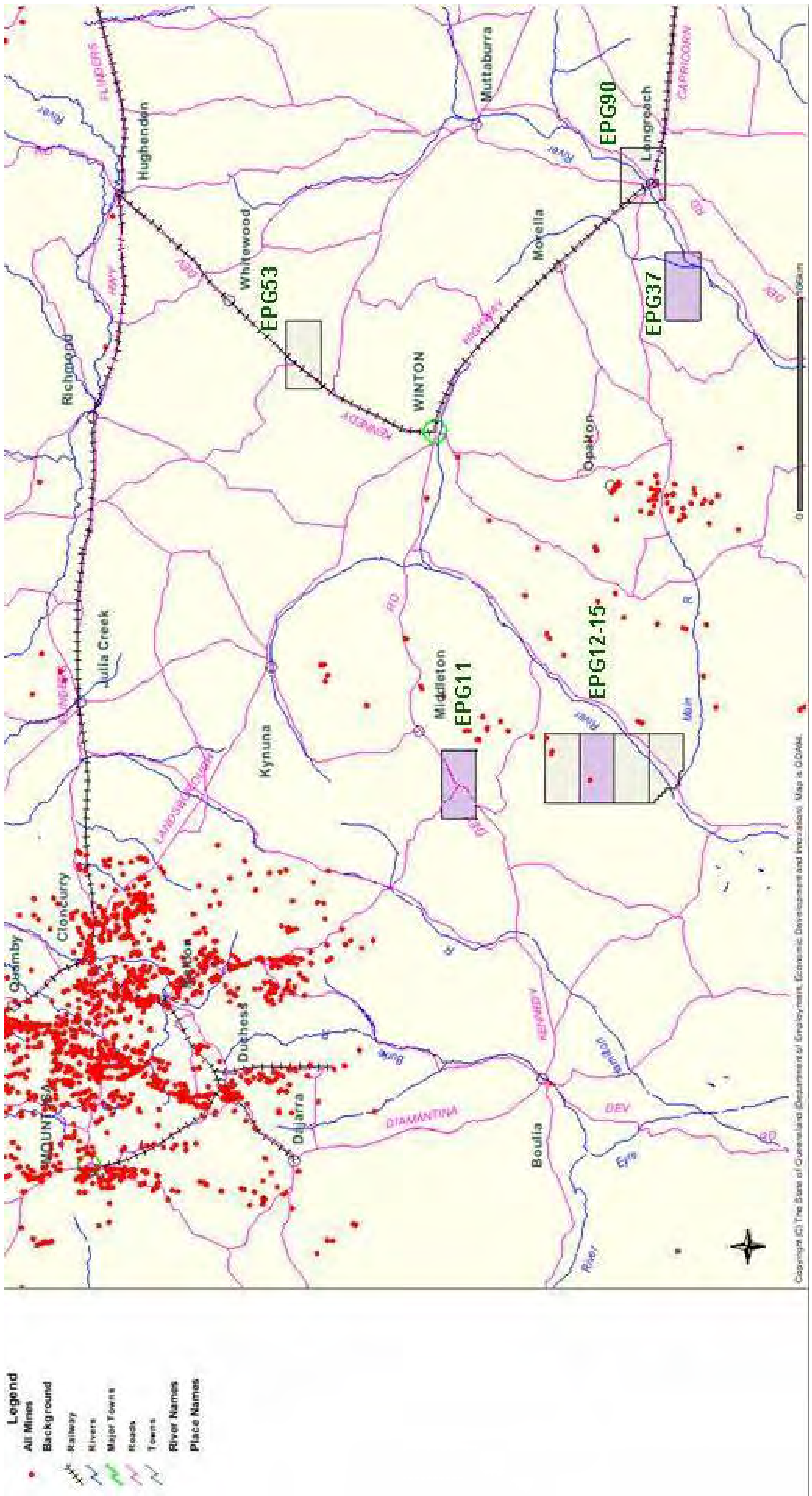
• Figure 1 - Geothermal Heat Extraction

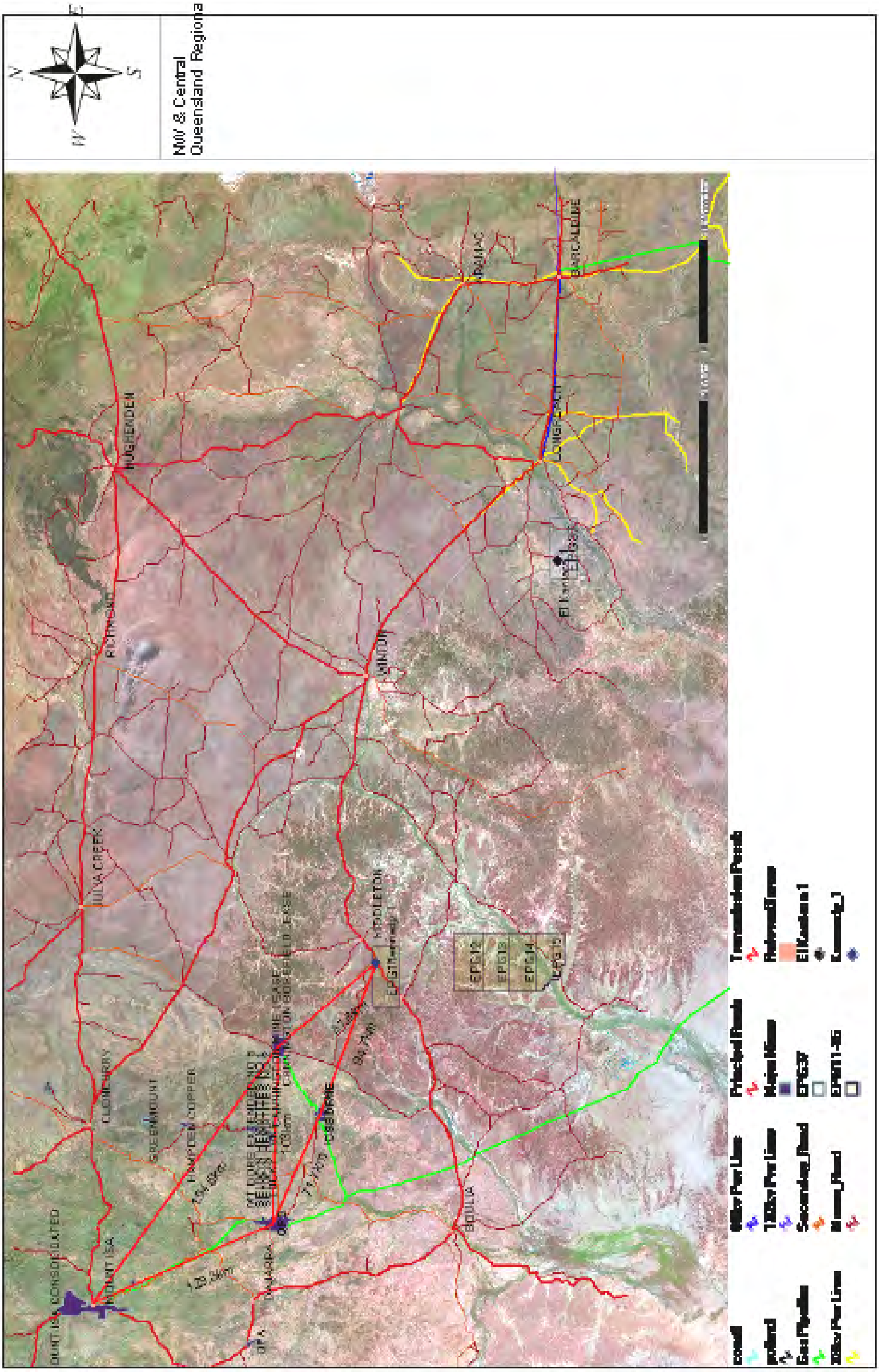
Australia thermal map at 5km depth with CEA Tenements overlay.



• Figure 2 - Australian Thermal Map

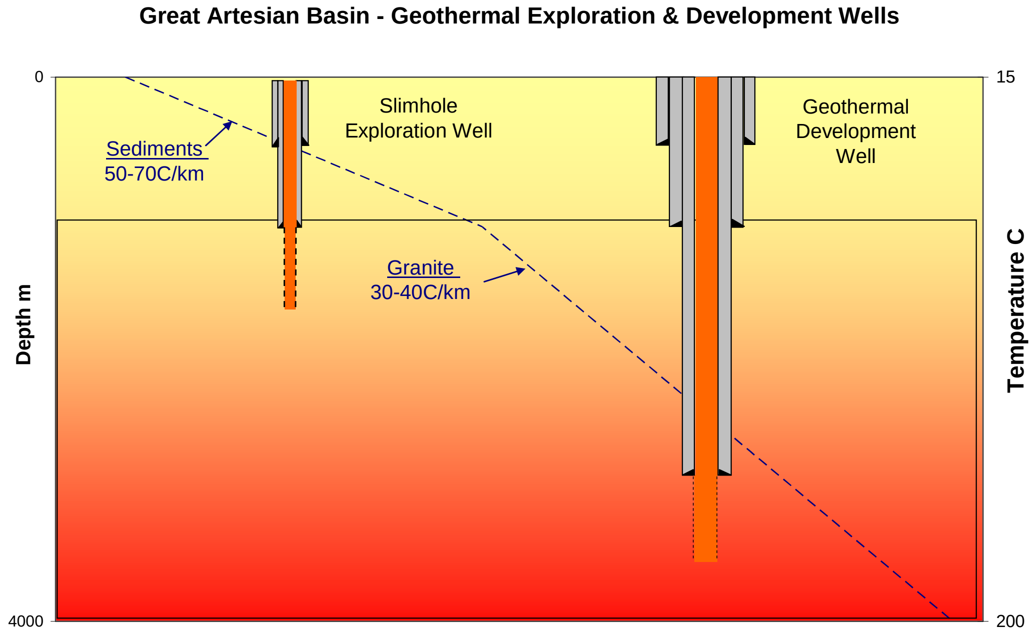
North / Central West QLD Mining and Regional Centres with CEA Tenements overlay



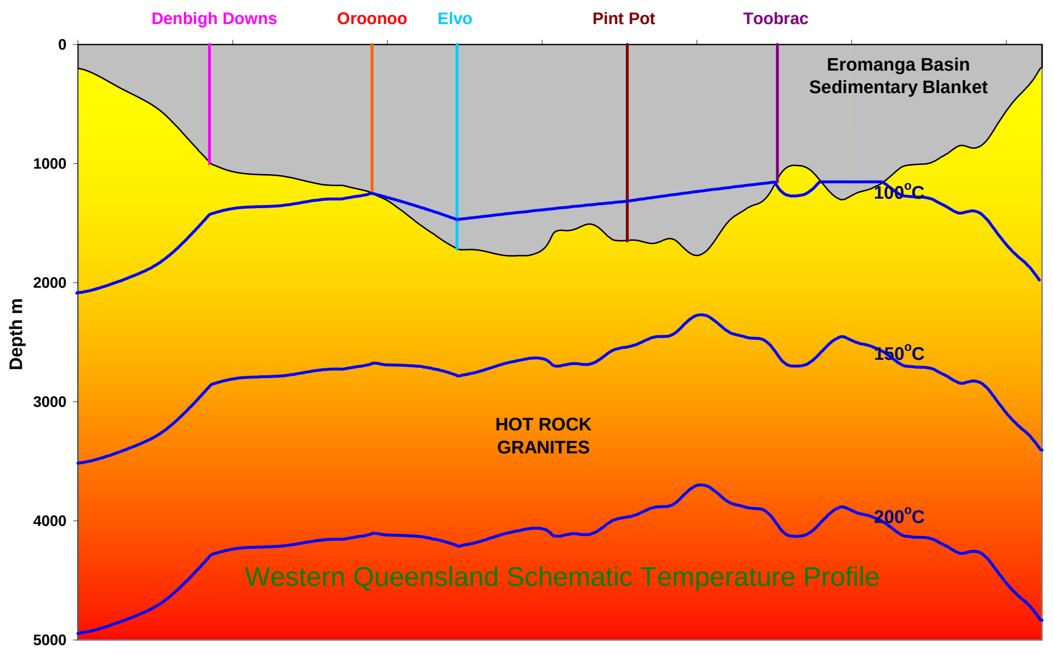


• Map 1- CEA Western Queensland Tenements

CEA Western Queensland Tenements

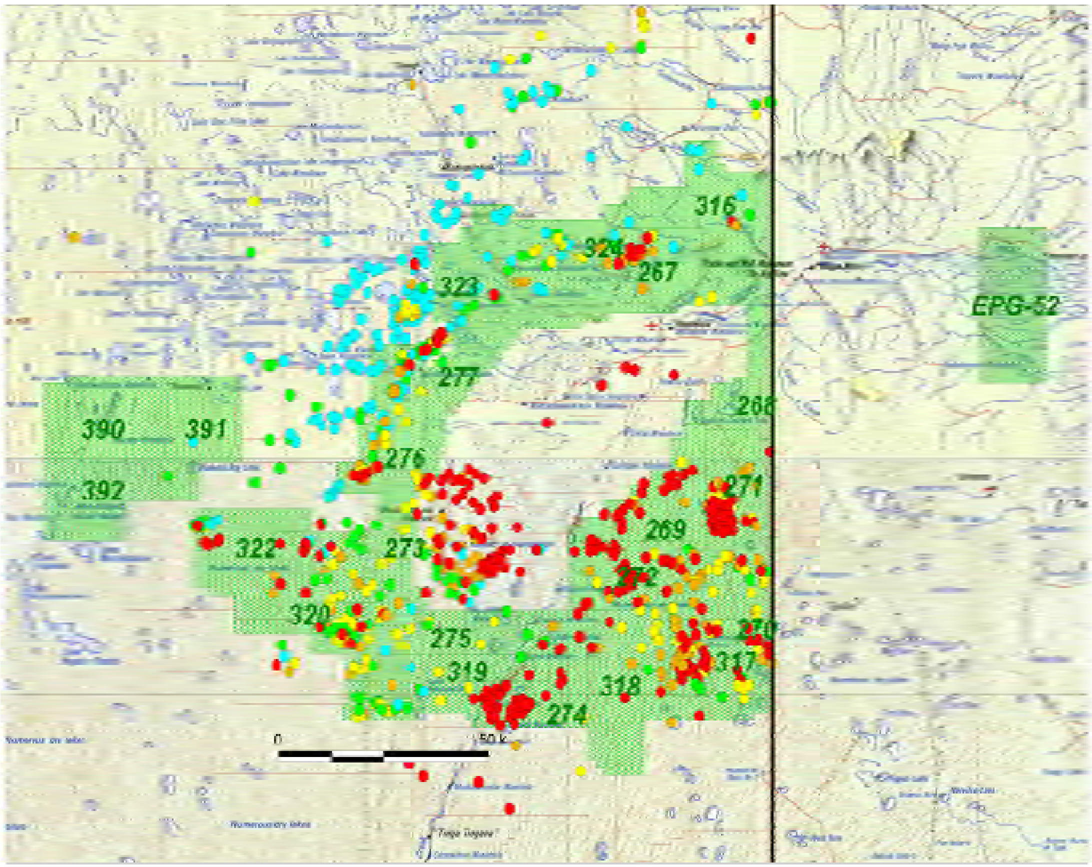


• Figure 1 - Schematic Geothermal Wells

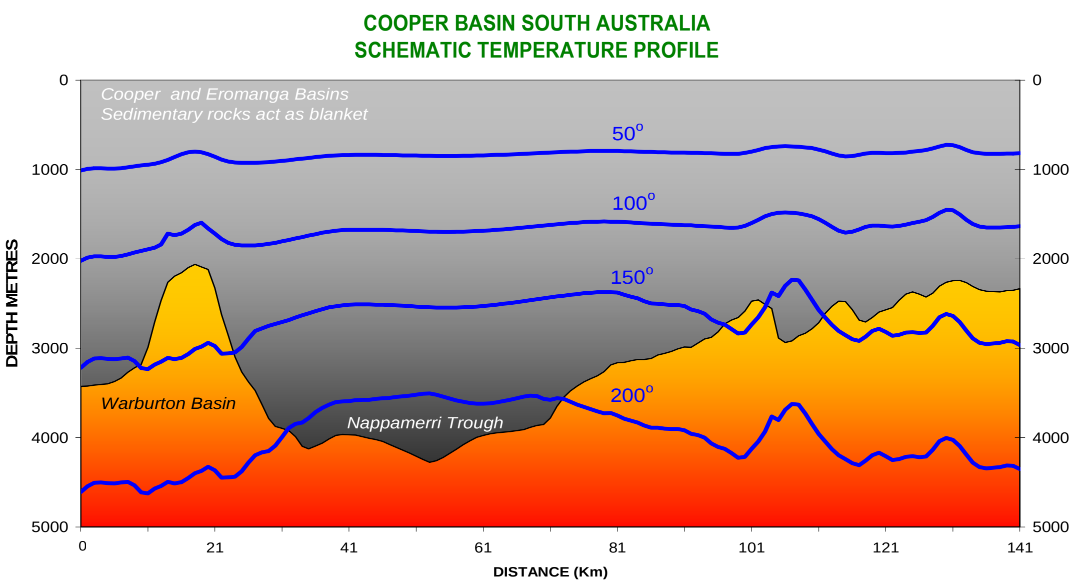


• Figure 2 Schematic Temperature Profile

CEA Cooper Basin Tenements

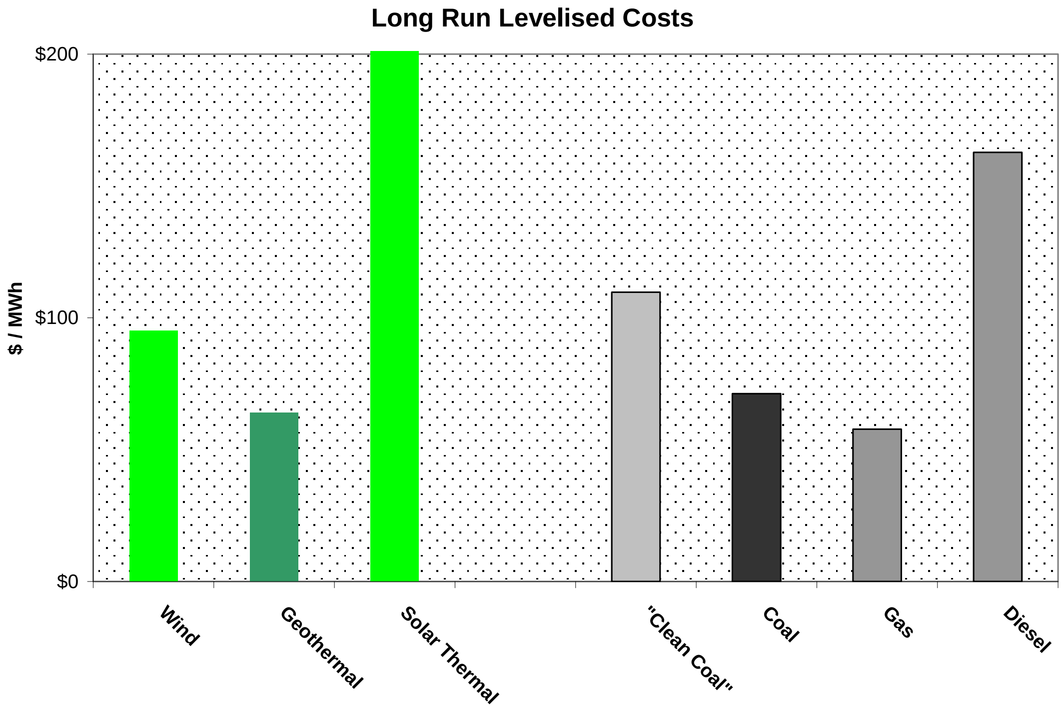


• Map 2 - CEA Cooper Basin Tenements

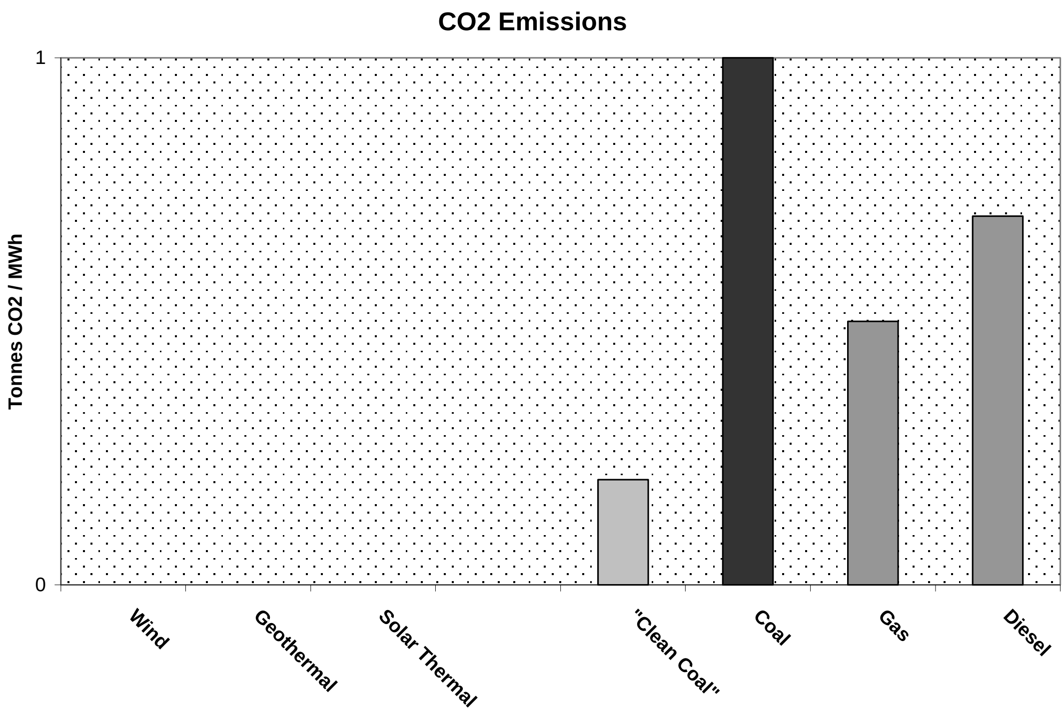


• Figure 5 - Cooper Basin Temperature Profile

Renewable Cost Comparisons



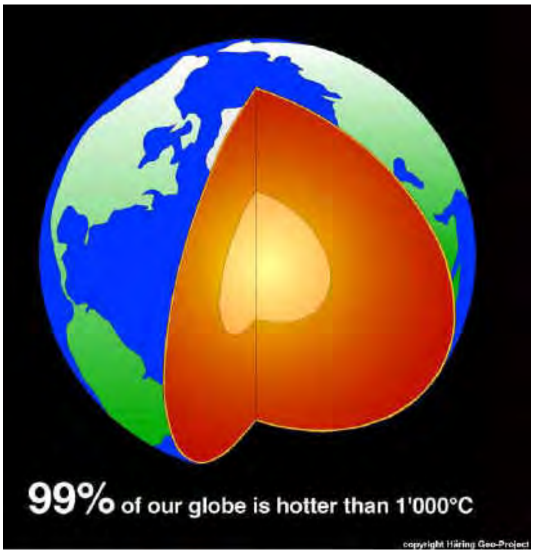
Emission Comparisons



About Geothermal

Geothermal Basics

- Geothermal energy is heat derived from the earth, it is renewable 24/7 and zero emission.
- Geothermal is a massive resource, only found in accessible depths in few locations
- Developments to date are mainly volcanic – can be readily adapted to Australian and in particular Queensland hot rocks,
- Essentials for good resource are the hot rock heat source, fluid to transfer heat to surface and permeable hot rock for fluid flow to bring heat to the surface

o 

Geothermal Worldwide

- Geothermal power generation is a mature technology, with a history of over 100years and with large scale plants operating for 50 years or more.
- Worldwide geothermal electricity generation exceeds 10,000MWe installed generation (approximately Queensland demand), with growth greater than 10% per annum
- Geothermal is cost competitive
- Australian and Queensland geothermal is in its infancy, commercialisation requires 10-100MWe projects

• Figure 6 - Geothermal world-wide Courtesy Panax Geothermal Ltd

Geothermal Power

- Water pumped into injection well
- Circulated through fractured hot rocks in sub-surface
- Super-heated water / steam is then returned to the surface through production well
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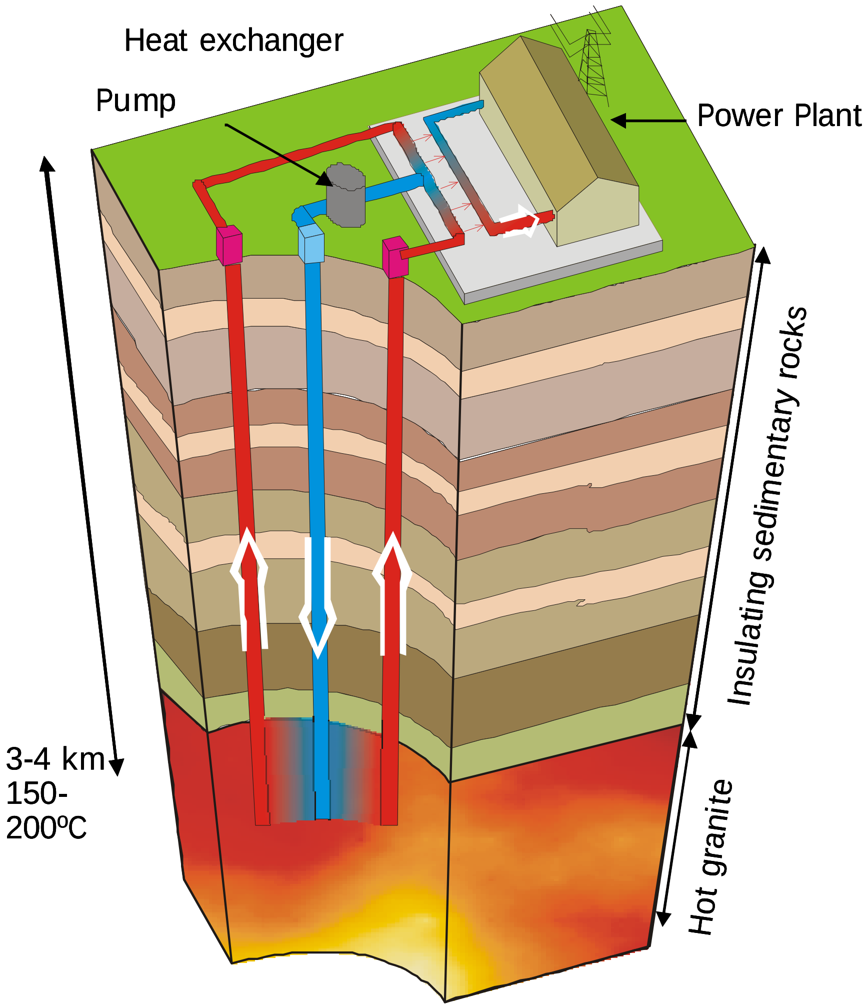
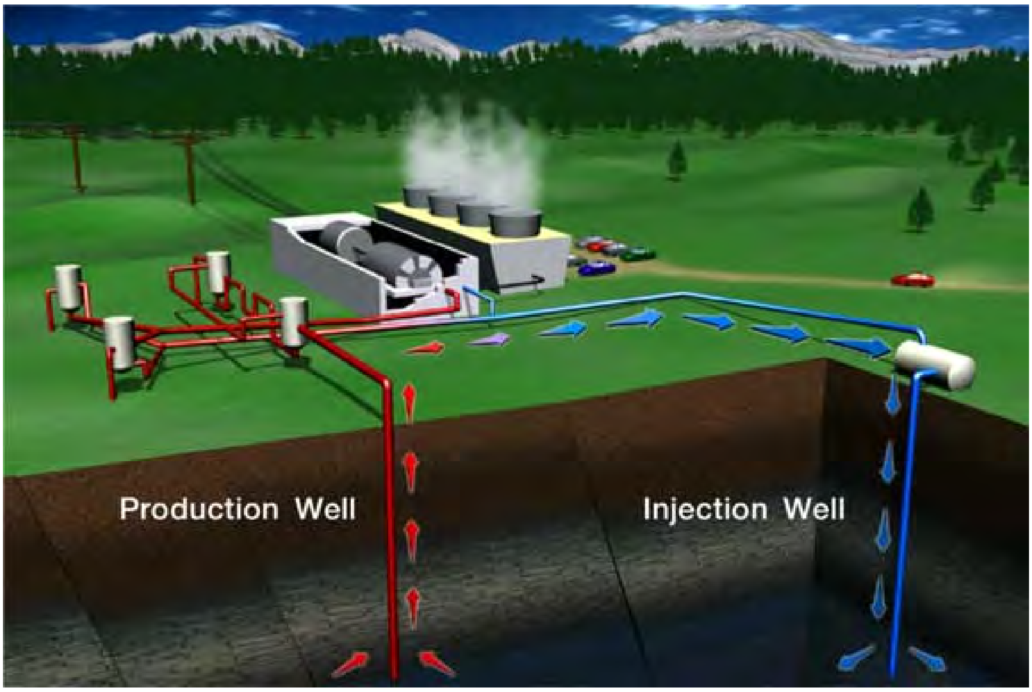


Geothermal Power Benefits

- Geothermal power is base-load 24*7 operation
- Zero green-house gas emissions
- Price competitive
- Minimal fuel cost
- Very large potential energy source
- Low surface impact
- Large turn-down ratio
- No waste disposal
- Security of supply



Electricity Price Outlook

- Geothermal market segment is Base Load Power
- Comparative Capital is:-
    - Coal $3+ million / MW +fuel +carbon tax + high emissions
    - 'Clean Coal' $10+ million / MW +fuel + social concerns
    - Nuclear ~$7 million / MW +fuel +social objection
    - Geothermal outlook $5-7million / MW no fuel no carbon tax no social objection.
- Solar cannot do base load without major storage
- Wind is intermittent, in the same position as Solar
- So is tidal

Appendix 1: House of Lords Inquiry

HOUSE OF LORDS

Select Committee on Economic Affairs

4th Report of Session 2007–08

The Economics of Renewable Energy

Volume I: Report

Ordered to be printed 12 November 2008 and published 25 November 2008

Published by the Authority of the House of Lords

London : The Stationery Office Limited
£price

HL Paper 195–I

See enclosed CD

HOUSE OF LORDS

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HL Paper 195–I

The Economic Affairs Committee

The Economic Affairs Committee is appointed by the House of Lords in each session with orders of reference "to consider economic affairs"

Current Membership

The Members of the Economic Affairs Committee are:
Lord Best
Lord Griffiths of Fforestfach
Baroness Hamwee
Lord Kingsdown
Lord Lamont of Lerwick
Lord Lawson of Blaby
Lord Layard
Lord Macdonald of Tradeston
Lord MacGregor of Pulham Market
Lord Moonie
Lord Paul
Lord Turner of Ecchinswell *
Lord Vallance of Tummel (Chairman)

* Lord Turner has not taken part in the work of the Committee since July 2008.

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Contact Details

All correspondence should be addressed to the Clerk of the Economic Affairs Committee, Committee Office, House of Lords, London SW1A 0PW
The telephone number for general inquiries is 020 7219 6968
The Committee's email address is economicaffairs@parliament.uk

CONTENTS

NOTE:
(Q) refers to a question in oral evidence
(p) refers to a page of written evidence

The Report of the Committee is published in Volume I, HL Paper No. 195-I
The Evidence of the Committee is published in Volume II, HL Paper No 195-II

ABSTRACT

The British economy will increasingly feel the impact of the Government's commitment to reducing carbon emissions, including targets for greater use of energy from renewable sources. The Government describes its targets for renewables as challenging; others have suggested they are unachievable. In any event, the effort to meet them will come at a cost and, if not properly managed, risks distracting attention from other means of reducing emissions.

It seems timely, therefore, to examine the economics of renewable energy. We take as a given the Government's wish to reduce carbon emissions; we do not address how far such reductions are justified as a contribution to a world-wide effort. We note the following main points:

—EU targets have focussed the spotlight on renewables rather than other means of reducing emissions such as energy efficiency or greater use of nuclear power.

—The EU is committed to a binding target that 20% of its energy consumption should be from renewable sources by 2020. Individual states' contributions to the overall target are still only proposals and some remain a matter of dispute. The Government seems ready to accept the Commission's proposal that the UK target should be 15% of energy from renewables by 2020.

—The expected UK target implies a dash from 1.8% renewable energy now to a near-tenfold increase in 12 years.

—Most of the increase in renewable energy in Britain is expected to come from electricity generation—although electricity represents only a fifth of the country's energy consumption—with an anticipated rise from 5–6% renewables now to 30–40% in 2020.

—Most of the extra renewable generation is expected from wind turbines, which offer the most readily available short-term enhancement of renewable electricity at a relatively cheap base cost; but they produce electricity only intermittently and the scope in the UK for increases in more dependable supply from other renewable sources—particularly hydro-electric, domestic biomass and solar—is limited, while tidal barrage and wave are still at an early stage of development in Britain.

—To make up for its intermittency, a significantly greater capacity of wind than of conventional or nuclear plant is needed for any given output of electricity; furthermore, in the absence of technological advances in electricity storage and of greater interconnection of the British and Continental transmission networks, back-up conventional plant will be essential to guarantee supply when required, to compensate for wind's very low capacity credit (probable output of power at the time of need).

—Wind generation should be viewed largely as additional capacity to that which will need to be provided, in any event, by more reliable means; and the evidence suggests that its **full** costs, although declining over time, remain significantly higher than those of conventional or nuclear generation.

—The dash for intermittent renewable generation will coincide with, and be in addition to, the programme to replace substantial amounts of old coal and nuclear plant and to meet increases in demand—amounting to about a quarter of current capacity.

—In short, the pursuit of a 15% renewables target will roughly double the requirement for new capacity for power generation that would otherwise be due in the UK between now and 2020; the scale and urgency of such investment is formidable. It is also subject to planning consents.

—The extra cost of electricity generation and transmission in Britain in 2020 with 34% renewables is likely to be £6.8billion a year, an extra 38%. Most of this would be met by the consumer; about £80 a year (at current prices) for the average household.

—There would be little investment in renewable electricity generation without Government support.

—Heating and transport each represent some two-fifths of the country's energy consumption but have received relatively little Government support or attention by comparison with electricity generation.

The UK has a poor record in meeting targets in this area and it must be doubtful whether a 15% EU target can be met under current policies. If it were met, it would mark a step change in the use of renewable energy but take Britain into a degree of dependence on intermittent renewables unprecedented elsewhere in Europe, with the attendant risks. Determination to meet the target may lead to over-emphasis on short term options, simply because they are available, rather than because they offer the most effective and economical means of reducing carbon dioxide emissions over the longer term.

The Government rightly aims to ensure reliable and affordable energy supplies and is right to say that a portfolio of policies is needed if we are also to reduce carbon emissions. But, in pursuing its renewable energy target, to guard against the risk of power shortages it should look beyond the generation of electricity by intermittent means and encourage other economic and effective ways of reducing carbon emissions across all sectors, so that investment in them is not diverted by incentives for intermittent sources of supply. Specifically, the Government should:

—Give a firm lead and maintain a stable investment framework for large-scale, low carbon alternatives to renewable power generation. Nuclear is not intermittent; neither is fossil fuel generation with carbon capture and storage, if and when that becomes available.

—Emphasise and promote the opportunities for renewable heat as strongly as for renewable electricity generation.

—Look afresh at the UK's research effort into renewables and consider how to promote more, and more focussed, research leading to new, effective and economical ways to reduce carbon emissions; it should also consider offering a substantial annual prize for the best technological contribution.

—In particular, encourage research into energy storage technologies with a view to mitigating the disadvantage of intermittency in the types of renewable generation likely to prevail in the UK.

The Economics of Renewable Energy

CHAPTER 1: INTRODUCTION

1. The Government is committed to a substantial increase in renewable energy over the next decade as a major part of its programme to reduce carbon emissions. Currently 1.8% of energy used in Britain comes from renewable sources—the Government aims to increase this to 15% by 2020 in line with European Commission proposals.[1] Greater use of renewables is expected to increase energy costs. But the cost of non-renewable sources of energy can also rise as recent volatility of oil and gas prices shows.

2. We decided it would be timely to examine the economics of renewable energy. The Committee's starting point is the Government's wish to reduce carbon emissions—this report does not discuss whether or how far it is necessary to do so. An earlier report by the Committee on climate change examined the issue in 2005.[2]

3. Chapter 2 gives a brief overview of Britain's energy system and outlines the Government's energy policy objectives.

4. Chapter 3 examines the different renewable technologies used to generate electricity. Electricity generation is often cited as the sector with the most potential for increasing the use of renewable sources, although it represents only around 20% of UK final energy consumption. The chapter compares the generation costs from different renewable sources with each other and contrasts them with fossil fuel-fired plants and nuclear power.

5. In Chapter 4, we move from power generation to the electricity system as a whole. We explore the issues involved in balancing the irregular supply from renewable generators which depend on weather conditions against the continuous demand for electricity. We examine the costs of connecting renewable generators to the electricity grid which carries power to homes and businesses across the country.

6. In Chapter 5, we examine the potential for renewable sources of heat and of transport fuels—areas often overlooked, although they represent roughly 80% of UK energy consumption. We look at the options in these sectors and compare the costs to those of renewable electricity generation.

7. Chapter 6 looks at the key policy issues surrounding renewable energy, such as how much support, and of what kind, the sector should get. We consider the impact of renewable policy on fuel poverty, the planning system for renewable energy, and whether the 15% target proposed by the European Commission is achievable.

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[1] The European Commission has set a binding target that 20% of the EU's energy consumption must come from renewable sources by 2020. However, the individual member states' contributions to this target are still only proposals and are a matter of dispute. For the United Kingdom, the European Commission has proposed that 15% of its energy come from renewable sources.

[2] House of Lords Select Committee on Economic Affairs, 2nd Report (2005–06), *The Economics of Climate Change*, (HL 12)

8. To keep the scope of this report manageable, we decided not to cover energy efficiency. It remains the case, however, that improvements to the way in which we use energy may be among the most cost-effective ways to reduce carbon emissions. We emphasise that nothing in this Report should be taken to imply that we do not recognise the critical importance of energy efficiency measures.

9. The geographical focus of the Report is the UK and the EU. The electricity system in Northern Ireland is run separately from that in Great Britain; almost all the evidence we received related to the system in Great Britain. As witnesses noted, the impact on carbon emissions of measures taken in the UK on its own (or, indeed, even in Europe as a whole) is likely to be minimal unless similar policies are adopted elsewhere.

CHAPTER 2: RENEWABLES AND THE UK ENERGY SYSTEM

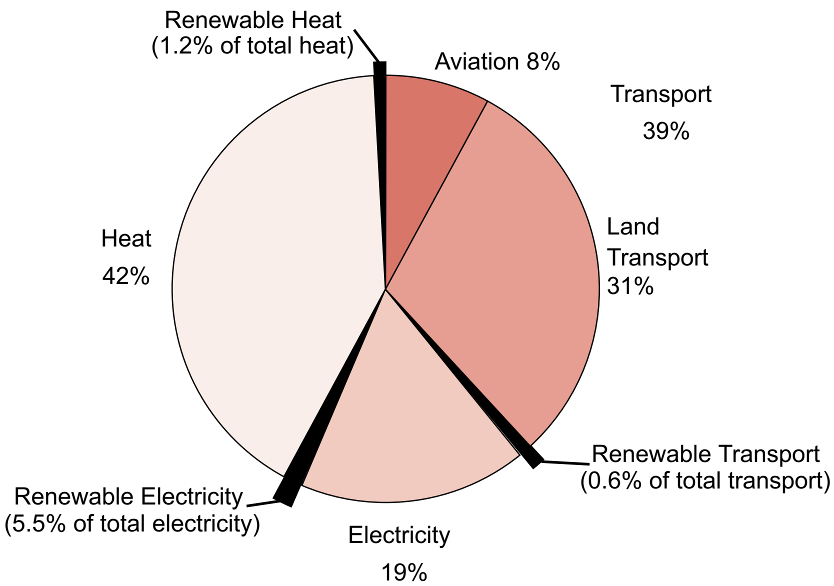
10. Renewable energy differs from conventional fossil fuel or nuclear energy in that the latter are dependent on finite resources, while the former is not. Currently renewable energy supply is only a small part of Britain's energy system. In this chapter we give an overview of the energy system and the Government's energy objectives.

Britain's energy system

11. There are three main uses for energy—heating, transport and as electricity. In 2007 heat accounted for 42% of final energy consumption in the UK, transport for 39% and electricity for 19%.[3] The share of heat has been falling in recent years, and those of transport and electricity have risen. Overall, renewables accounted for only 1.8% of energy used in Britain, calculated on the basis used by the European Commission.[4] Most of this has been to generate electricity. About 5.5% of electricity came from renewables in 2007 but only around 1% of the energy used in heat and transport was renewable.

FIGURE 1

Energy Mix 2007



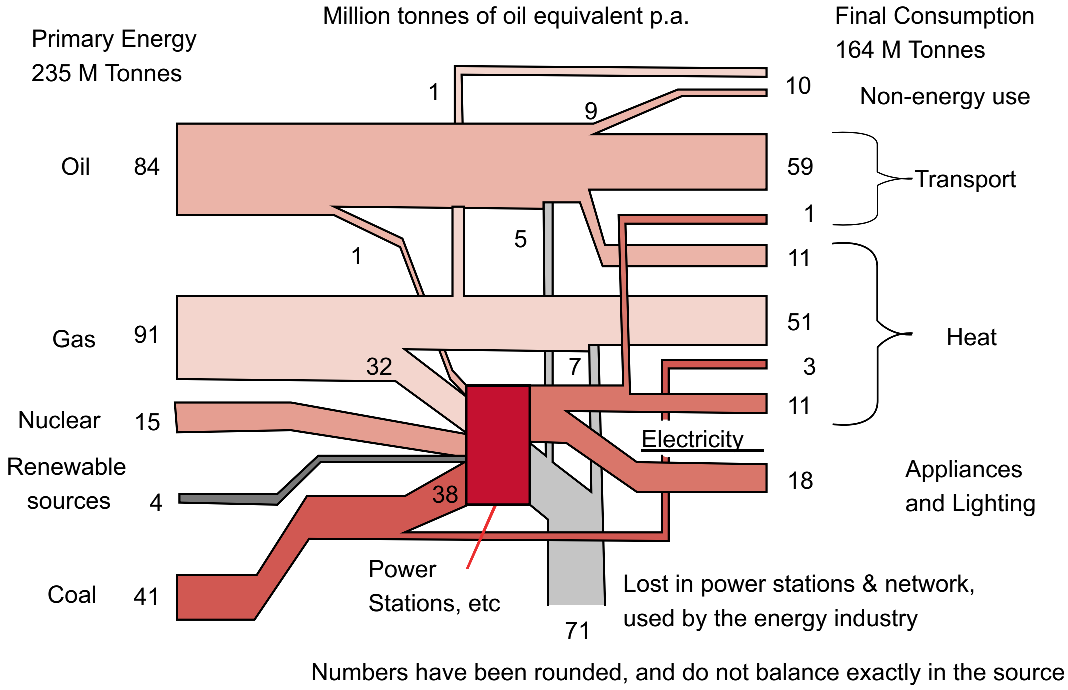
Source: Digest of UK Energy Statistics

[3] Digest of UK Energy Statistics, 2007 edition. Electricity used to provide heat is counted as "electricity" rather than as "heat". Final energy consumption, as defined in UK statistics, also includes non-energy use—mainly when oil and gas are used as chemical feedstocks—which makes up 6% of it.

[4] The European Commission excludes the non-energy use of oil and gas, and includes electricity used at power stations and lost in transmission and distribution networks—both changes have the effect of raising the share of electricity in final energy consumption, compared to the standard UK definition.

FIGURE 2

Energy flows in the UK, 2007



Source: BERR

12. Figure 2 shows the main sources of energy, giving domestic production plus net imports of coal, oil, gas, nuclear electricity and renewable power, measured in millions of tonnes of oil equivalent.[5] Oil is by far the most important transport fuel, but around 11 million tons is used for heating. A small amount is burned in power plants to generate electricity, and a significant quantity is used outside the energy industry, as a chemical feedstock. Gas and coal are burned in power plants to generate electricity (in roughly equal amounts) and are also burned to provide heat. The other sources of electricity are from using uranium in nuclear power stations, and from renewable power sources. Only part of the energy that goes in to power stations is converted into electricity, while the rest is lost as waste heat. Electricity is also lost in the transmission and distribution wires, while some gas is used to power the compressors that move it around the pipeline network. These losses are shown in the flow that leaves the bottom of the diagram. Nearly two-thirds of our electricity is used for lighting and appliances, where it has no effective substitute, but much of the rest is used for heat. This is illustrated approximately in Figure 2, which shows a higher overall share of heat than Figure 1. A small proportion of our electricity is used in transport, mainly on the railways.

The electricity system

13. Much of this report is concerned with the use of renewable sources to make electricity. Unlike coal, gas and oil, electricity cannot be stored easily on a large scale. This means that we must consider the industry's capacity—the amount that can be produced at any moment—alongside the energy that it

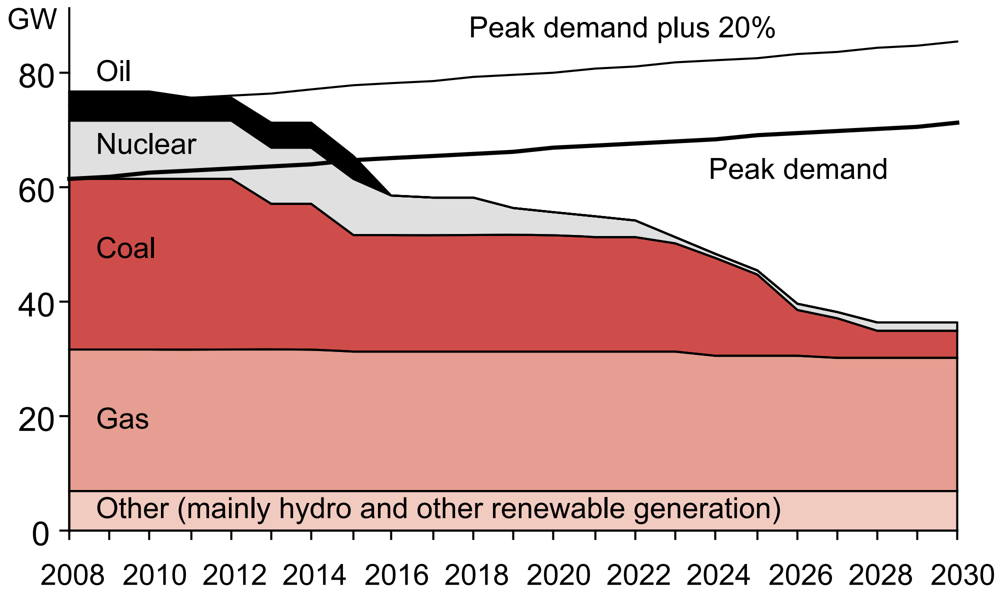
[5] A million tonnes of oil equivalent—the unit used in Figure 2—is the amount of energy released by burning 1m tonnes of crude oil, and is equal to 11.63 billion kilowatt hours (the standard unit of electrical energy). A one bar electric fire consumes approximately one kilowatt of power.

produces. Britain has 76 GW (1 GW = million kilowatts) of electricity generating capacity, a margin of roughly 25% over the highest electricity demand in 2007 of 61.4 GW. Average demand was just under 40 GW. The largest power station in Britain, Drax in Yorkshire, has a capacity of 4 GW, but most of the gas-fired power stations built in the last two decades have a capacity of between half and one GW.

14. Even without renewables, Britain's electricity system will go through a period of heavy investment. 18 GW—almost a quarter—of electricity generating capacity is due to close by 2020. Of this, 8.5 GW of coal-fired plants will close to meet EU requirements on pollution[6] as will another 2.5 GW of oil-fired stations. A further 7 GW of nuclear power is scheduled to close by 2020, based on the published lifetimes of the plants (which have, in the past, been extended, subject to meeting safety requirements). The impact of these closures on Britain's electricity generating capacity is shown in figure 3 below. In the meantime, demand for electricity is also expected to increase which will also have to be met by greater capacity. The dotted line shows a 20% margin over peak demand which is the current amount of spare capacity available to ensure there are no power cuts when power plants need to be turned off for maintenance and repairs. If this margin is to be maintained at around 20% then new power stations need to be built in good time to replace these closures and to meet increases in demand. On this basis, the Government has calculated that around 20–25 GW of new power stations will be needed by 2020.[7] These figures do not take the new renewables targets into account.

FIGURE 3

Predicted electricity demand and generation capacity after forecast closures



Source: E.ON UK

6 The Large Combustion Plant Directive requires coal- and oil-fired power stations either to fit Flue Gas Desulphurisation equipment or to close by the end of 2015.

7 Department of Trade and Industry, *Meeting the Energy Challenge*, A White Paper on Energy, May 2007, p 128–129.

Energy policy objectives

15. In last year's energy white paper the Government said, "Our four energy policy goals are:

- to put ourselves on a path to cutting the UK's carbon dioxide emissions—the main contributor to global warming—by some 60%[8] by about 2050, with real progress by 2020;
- to maintain the reliability of energy supplies;
- to promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity; and
- to ensure that every home is adequately and affordably heated".[9]

16. The Government's second objective—maintaining the reliability of electricity of energy supplies—has several aspects. The country must have access to sufficient supplies of primary energy; it must have an adequate infrastructure for delivering those supplies to consumers; and that infrastructure must be available when required.[10] Long-term security of supply—availability of primary energy—is normally improved by having access to a portfolio of energy sources, diversified both in terms of fuel and (if imported) source country. Increasing the use of renewable energy in the UK will add diversity to our portfolio, but will not necessarily add to reliability of supply, as some forms of renewable electricity generation will not always be available when required, depending on the wind, the waves, the tides or the sun.

Renewables and energy policy

17. The Government's main reason for increasing the share of renewable energy is to contribute to the reduction of carbon emissions. Some renewable generators emit practically no carbon dioxide when they are running (such as wind power). In others such as those using biomass (fuel from organic matter) most of the carbon released was taken from the atmosphere by the plants used.

18. The EU has agreed on a legally binding target for renewable energy equal to 20% of the total of all member states' overall energy consumption in 2020.[11] At present, the European Commission has proposed different targets for different countries in order to meet the overall 20% target. Some of these are still the subject of dispute within the EU. In the UK's case the proposed EU target is 15% of energy from renewables, which the Government describes as "very challenging".[12]

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8 The Secretary of State for Energy and Climate Change announced on 16 October that "The Government accept all the recommendations of the Committee on Climate Change. We will amend the Climate Change Bill to cut greenhouse gas emissions by 80 per cent by 2050, a target that will be binding in law." Hansard, 16 October 2008, cols 935–937.

9 Department for Trade and Industry, *Meeting the Energy Challenge*—A White Paper on Energy, May 2007, p 6.

10 Department for Business, Enterprise and Regulatory Reform and Ofgem, *Energy Markets Outlook*, October 2008, Chapter 3.

11 The House of Lords EU Committee, 27th Report (2007–08) *Renewable Energy: The EU's 20% by 2020,* (HL 175).

12 Department for Business, Enterprise and Regulatory Reform, *UK Renewable Energy Strategy* consultation, June 2008, p 3.

19. Renewable energy is not the only way to reduce carbon emissions. Nuclear power is a well established low carbon source of electricity. Coal-fired power plants with carbon capture and storage (CCS) might at some point be another option but it is still unclear if and when they will become practicable (EDF p 272, British Energy pp 238, 243).[13] Although the main technologies involved are all, separately, in operation, no commercial-scale power plant has yet been fitted with CCS (E.ON QQ 237–9). E.ON expects CCS to be competitive with costs of conventional fossil generation if the price per tonne of CO_2 under the EU Emissions Trading Scheme rises to Euro 40–50—roughly double the current level (Q 213).

20. Some have argued that renewables can also help with another aim, increasing security of supply. (BERR p 210, EDF pp 272–273, Scottish & Southern p 92). As noted in paragraph 16 above, renewables might do so by increasing the diversity of Britain's energy sources. This could be important as Britain's domestic sources of oil and gas dwindle—three-quarters of the UK's gas is expected to be imported by 2015 compared to around 20% today (Centrica p 96). Many of these imports are expected to come from regions where political as well as market factors could affect supply.

21. These developments are occurring amid high and volatile wholesale energy prices. The risk is less that Britain's oil and gas supplies would be cut off and more that it would be exposed to volatile price swings by having to rely more on imported oil and gas. In addition to the political and price risks, while new oil and gas reserves continue to be found they are in less accessible locations from which they are expensive to extract. James Smith, chairman of Shell UK, said: "The 'easy' oil and gas has probably been found and produced." (Q 336)

22. Exposure to price volatility could be lessened by using renewables. But greater use of nuclear power and/or coal—of which Britain and close geopolitical allies such as Australia still have large supplies—could provide similar benefits.

23. Furthermore, renewables have a potential **negative** effect on security of supply in that they can be markedly less reliable than fossil fuels in generating energy to meet peak demand. For example, wind turbines produce no power if the wind does not blow or blows too hard. To provide an acceptable level of security, it is necessary either to have strong interconnections to other countries (which the UK lacks) (British Energy p 238) or to build a significantly higher level of overall capacity than in an equivalent system without wind power. Both of course significantly add to the cost of electricity.

24. We have received different estimates of where the 15% share of renewable energy might come from. All expected a higher share of renewable electricity than of transport fuel or heat. The range of estimates of the share of electricity generation from renewables needed in 2020 to meet the target is from 30 to 40%. Those based on a 10% share of renewable energy in transport (the level set by EU policy) and on 10% in heat imply 40% renewable electricity. The Government expects to achieve a heat share of 14%, reducing the share expected of renewable electricity to 32%. Given the much larger share expected in electricity, we turn to this sector in Chapters 3 and 4. We return to heat and transport in Chapter 5.

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[13] In May 2007, Alistair Darling, the then Secretary of State for Trade and Industry, warned that carbon capture and storage at coal-fired power plants "might never become available". Hansard, 23 May 2007, column 1289

CHAPTER 3: TECHNOLOGIES FOR RENEWABLE ELECTRICITY GENERATION

25. This chapter focuses on renewable technologies for electricity generation, considering each of those technologies in isolation. The following chapter deals with the costs of connecting renewable generators to the electrical system as a whole, and operating them in a coordinated way to meet demand.

26. Electricity can be generated from five groups of renewable sources which are used to varying degrees in Britain. These are briefly outlined below[14] with more details about their potential in Appendix 4.

Wind

27. Wind is likely soon to become Britain's largest source of renewable electricity generation. There were 179 onshore wind farms in October 2008 which can generate up to 2.3 GW—the equivalent of nearly 3% of Britain's electricity capacity. Another 424 farms are under construction or going through the planning approval process, which would give a total capacity of 13.8 GW.

28. So far there are only eight offshore wind farms in operation, with 0.6 GW of capacity.[15] But offshore wind is seen as a major source of growth of renewable energy. The Government has awarded leases to developers with proposed projects that could generate up to 8.2 GW of power—just over 10% of current generating capacity.[16] It has announced plans to allow the development of a further 25 GW of capacity.

29. Both onshore and offshore wind generation, by their very nature, are intermittent—when the wind does not blow or is too strong, electricity is not generated. It is therefore particularly important to consider the load factor achieved by a wind generator when calculating its costs and its value to the system. The load factor is the actual electricity generated expressed as a percentage of the potential amount had the turbines been operating at full capacity all the time. An indicative figure of 30% is often used but in practice the average load factor for onshore wind farms in 2007 was 27.5%.[17] Professor Michael Jefferson used Ofgem data to show that only 13.6% of 81 onshore wind farms examined in England achieved load factors of 30% or over in 2007. In other words, the vast majority—86.4%—were generating less than 30% of their capacity. In Scotland one third of wind farms achieved a load factor of 30%, in Northern Ireland 26% but in Wales the figure was less than 20% (Jefferson p 376).

30. Offshore wind generators are expected to have a higher load factor than those onshore, but those in operation achieved only 28.3% in 2007. Other

14 Much of the material for the definitions of different forms of renewable generation came from Department for Business, Enterprise and Regulatory Reform (2008), *UK Renewable Energy Strategy*; Consultation Document, p 53–60.

15 British Wind Energy Association at http://www.bwea.com/offshore/index.html.

16 The 8.2 GW includes the eight offshore wind farms that are already up and running. Figures calculated from BERR consultation document, p 55.

17 Digest of UK Energy Statistics, 2008, table 7.4.

types of generator have suffered teething problems which have reduced their load factors in their early years of operation. Dr Simon Watson told us that the output from offshore turbines was likely to be less variable (Q 22).

31. Dr Watson told us that micro-generation from wind suffered because small turbines were less efficient. Large turbines were able to extract energy from the wind close to the theoretical maximum of 59%, whereas small turbines could only extract half as much. Furthermore, in urban areas, low and variable wind speeds meant that a typical wind turbine would have a load factor of only 1 or 2%. (QQ 26, 30)

32. Wind accounted for 43% of renewable generation electricity **capacity** in Britain at the end of 2007—37% onshore and 7% offshore. But the low load factor of wind farms means the proportion of electricity actually generated from renewables was much lower. Wind contributed about one quarter of the UK's renewable electricity generation—23% onshore and 4% offshore.

Wave and tidal generation

33. Wave and tidal generation come in three broad forms: **tidal ranges or barrages** trap water during high tide using barrages and lagoons before releasing it to turn turbines to generate electricity; **tidal stream** devices harness the energy from fast-flowing tidal currents; and **wave** power converts the energy contained in the movement of the waves into electricity. Professor Abubakr Bahaj told us that most tidal stream devices were based on the kind of turbines (with a horizontal axis) used in wind farms. Three technologies were competing in wave power. An oscillating water column allowed a wave to come into a chamber where it compressed air to drive a generator—the Limpet shore-based generator has been operating on Islay since 2000 (p 493). Pelamis Wave Power Limited, based in Edinburgh, is testing a series of articulated cylinders which will move up and down with the waves, compressing air to power a generator. The third technology is a power point absorber which moves with the waves, capturing energy for generation (Q 39). Currently, there is next to no generation in Britain from these sources. Professor Bahaj told us that the majority of the devices were on hold waiting for investment in order to deploy prototypes. The Government's view is that these technologies are relatively undeveloped and unlikely to generate much electricity by 2020. Ignoring cost, in the longer term the UK has the potential for wave energy to generate about 15% of its current electricity consumption, and tidal stream energy to provide about 5%, according to the UK Energy Research Centre.[18]

34. Like wind, tidal power is intermittent. The key difference is that tidal power is as predictable as the tides while windspeeds cannot easily be foreseen.

35. With tidal range systems, however, water can be released to turn the turbine when electricity is needed, not just in response to tidal movements. This in effect means electricity can be stored for use when demand is high, whereas storage is very limited with wind and most other forms of renewable generation. Despite these advantages wave and tidal technologies are still

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[18] UKERC (2008) UKERC Energy Research Landscape: *Marine Renewable Energy*.

mostly at an early stage of development and are much more expensive than wind generation.

Hydroelectric

36. Hydroelectric power is the most developed source of renewable energy and makes up 27% of renewable generation capacity in Britain. Most (24% of the renewable capacity) consists of large-scale schemes with dams and reservoirs in mountainous areas. Because the water is stored, the generator has some flexibility over when to produce power, although there may be limits on the minimum and maximum quantities of water that can be released at any one time. Small-scale hydro generation schemes (those with a generation capacity below 5 MW, which make up 3% of the UK's renewable capacity) are often sited on rivers, with little water storage and hence less flexibility over when to generate.

37. In the Government's view the scope for further large-scale hydro-electric schemes is very limited for lack of suitable sites.[19] The British Hydropower Association say that another 3.2 GW of hydroelectric capacity could be built—the equivalent of 4% of the UK's current generating capacity (British Hydropower Association p 246). But the Institution of Engineering and Technology sees scope for only 1 GW of extra capacity (IET p 365 and in the table in Appendix 4).

Biomass

38. Biomass covers a range of renewable fuel sources derived from organic matter. In 2006, about 2.3% of electricity generated in Britain came from biomass sources such as landfill gas from the decomposition of organic material in landfills, sewage gas from biodegradable waste, wood from virgin timber, forestry management wastes and recovered waste wood, and specially grown energy crops. Sometimes these materials are burned with fossil fuels in power plants. Professor Tony Bridgwater told us that this was a very effective way of using renewable energy, since almost all the capital investment was already there (Q 33). With co-firing, a small amount of biomass could be used in a large, efficient, power station, whereas dedicated biomass plants were often small because they drew on limited nearby supplies of biomass fuel (Q 33). The most popular energy crops were willow and miscanthus grass. Willow could produce ten tonnes of biomass per hectare per year, miscanthus up to twenty (Q 31). Land available in the UK for growing biomass was limited, and farmers might be reluctant to commit themselves to a crop (like willow) that can only be harvested after several years: on one occasion, the power station that was to have bought the crop went bankrupt in the interval (Q 35).

39. Biomass is a versatile source of renewable energy, since it can be used, in solid form or as a gas (sometimes after conversion) for generating power and for heat. Professor Bridgwater also pointed out that biomass has unique advantages compared to other renewable energy sources as a source of

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[19] Department for Business, Enterprise and Regulatory Reform (2008), *UK Renewable Energy Strategy;* Consultation Document, June 2008, p 58.

carbon which can be converted into transport fuels[20] (Q 31). Other renewable sources mostly provide electricity, not yet widely used for transport. Professor Bridgwater also told us, however, that the crops grown in the UK for transport biofuels produce only about one tonne of biomass per hectare per year.

40. Landfill gas is currently the largest source of biomass generation in Britain. But there is little scope for growth in the short term as most large landfill sites are already being exploited. The use of landfill gas may even decline as existing sites are depleted. Any growth in biomass generation will likely come from burning more waste and/or energy crops. Energy produced from non-biodegradable materials such as plastics is not counted as renewable, although burning them may relieve the pressure on landfill sites.

41. Dedicated biomass power stations made up 29% of Britain's renewable generation capacity in 2007. Biomass, unlike wind, wave or tide, does not suffer the handicap of being intermittent. For this reason, biomass generators are used more intensively than most other renewable generators, so the share of electricity generation from biomass is greater than its share of capacity. Biomass provided almost half the UK's renewable electricity in 2007, with 24% from landfill gas, 10% from co-firing biomass in power stations, and 6% from municipal solid waste combustion. Sewage sludge and animal biomass each provided 3% of renewable electricity generation, and dedicated plant biomass stations produced 2%.

Solar

42. Solar energy can be used in a number of ways. For electricity generation the most common process is through solar photovoltaics. Solar PV cells have long been used to power small electronic devices such as calculators. But large groups of solar PV cells can be added together, powering small solar panels in individual households or larger arrays feeding power directly into the electricity grid. In 2007, solar PV provided 0.3% of the UK's renewable generation capacity and 0.1% of its renewable electricity. Professor Bahaj told us that the UK had a very limited resource for solar power, and the likely capacity factor was of the order of 11% (Q 45). Solar generation is more costly than most other forms of renewable generation.

Renewable generation mix

43. Figure 4 shows how much electricity each of the main types of renewable generator produced over the last few years—the key feature is the rapid growth of many kinds of output, particularly that of wind power. Appendix 4, provided by the Institution of Engineering and Technology, summarises its view of the main renewable generation technologies, with the current position, scope for further development, and the main barriers to further deployment.

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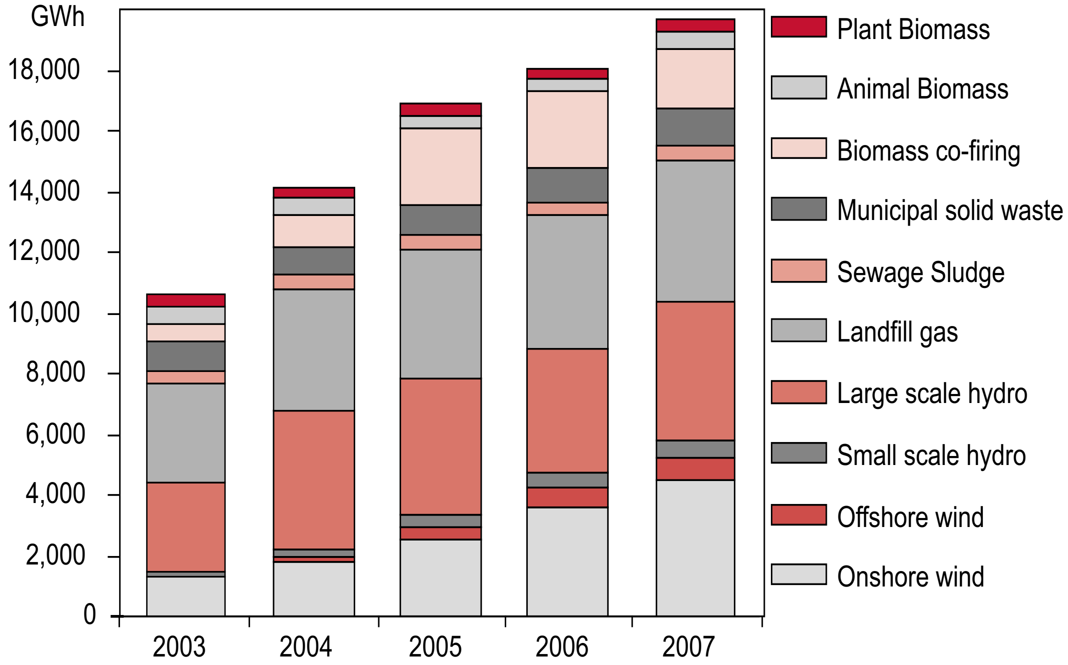
[20] Transport fuels based on oil are hydrocarbons, containing mostly carbon and hydrogen, as are their biofuel replacements.

FIGURE 4

Generation from renewables in the UK



Source: Digest of UK Energy Statistics, 2008, table 7.4

Britain compared to other European countries

44. About 4.6% of electricity in Britain in 2006 was generated from renewable sources—far below the European average of just over 14%.

45. As shown in Table 1, many countries which generate large shares of their electricity from renewables, such as Austria, Sweden, Portugal, Latvia, Romania and Slovenia, have an advantage in topography suitable for hydro-electric power. Around half of Austria and Sweden's electricity is generated from renewables—the highest in the EU—with the vast majority from hydro-electricity. Less than 10% of Austria's renewable generation comes from wind, biomass and solar power.

46. But some EU countries have reached higher levels of generation from renewables than Britain with little use of hydroelectric power: just over a quarter of Denmark's electricity comes from renewables with more than three-fifths of that coming from wind and most of the rest from biomass. In Denmark and Finland over 10% of electricity comes from biomass compared to 2.8% across the EU. The transmission networks connecting Denmark with its neighbours are strong. This eases the task of accommodating a large amount of intermittent generation. Spain, in contrast, has rapidly increased its use of wind power, despite having limited connections to its neighbours. Some countries with relatively high levels of (non-hydro) renewable generation have above-average carbon emissions, typically because they also generate a high proportion of their power from coal (Keay Q 82).

TABLE 1

Gross Electricity Consumption from renewable sources in the EU 2006 (in percentages)

	Total Share	Hydro*	Wind	Biomass	Solar	Geothermal	2010 TARGET
EU27	14.5	9.2	2.4	2.7	0.074	0.2	21.0
EU25 #	14.3	8.8	2.5	2.8	0.076	0.2	21.0
Belgium	3.9	0.4	0.4	3.1	0.002		6.0
Bulgaria	11.2	11.1	0.1				11.0
Czech Republic	4.9	3.6	0.1	1.3	0.001		8.0
Denmark	25.9	0.1	15.7	10.1	0.005		29.0
Germany	12.0	3.2	5.0	3.4	0.358		12.5
Estonia	1.4	0.1	0.8	0.4			5.1
Ireland	8.5	2.5	5.5	0.4			13.2
Greece	12.1	9.3	2.6	0.2	0.002		29.4
Spain	17.3	8.5	7.7	1.0	0.042		21.0
France	12.4	11.0	0.4	1.0	0.004		21.0
Italy	14.5	10.3	0.8	1.8	0.010	1.5	25.0
Cyprus	0.0				0.021		6.0
Latvia	37.7	36.5	0.6	0.6			49.3
Lithuania	3.6	3.3	0.1	0.2			7.0
Luxembourg	3.4	1.3	0.7	1.1	0.266		5.7
Hungary	3.7	0.4	0.1	3.2			3.6
Malta							5.0
Netherlands	7.9	0.1	2.3	5.5	0.029		9.0
Austria	56.6	49.6	2.4	4.5	0.021		78.1
Poland	2.9	1.4	0.2	1.3			7.5
Portugal	29.4	20.2	5.4	3.7	0.009	0.2	39.0
Romania	31.4	31.4	0.0	0.0			33.0
Slovenia	24.4	23.7		0.7			33.6
Slovakia	16.6	15.1	0.0	1.5			31.0
Finland	24.0	12.3	0.2	11.6	0.003		31.5
Sweden	48.2	41.3	0.7	6.2			60.0
United Kingdom	4.6	1.1	1.0	2.5	0.002		10.0
Croatia	33.4	33.2	0.1	0.1			
Turkey	25.5	25.3	0.1	0.0		0.1	
Iceland	100.0	73.4		0.0		26.5	
Norway	98.3	97.4	0.5	0.4			
Switzerland	49.5	46.4	0.0	3.1	0.034		

Source: Eurostat, May 2008 and Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market.
Total Share = a / (b+c)
a = Gross Electricity Generation from Renewable Sources
b = Total Gross Electricity Generation
c = Net Imports of Electricity
**Note: Does not include pumped storage*
 # EU 25 is the EU 27 less Bulgaria and Romania which joined in 2007.

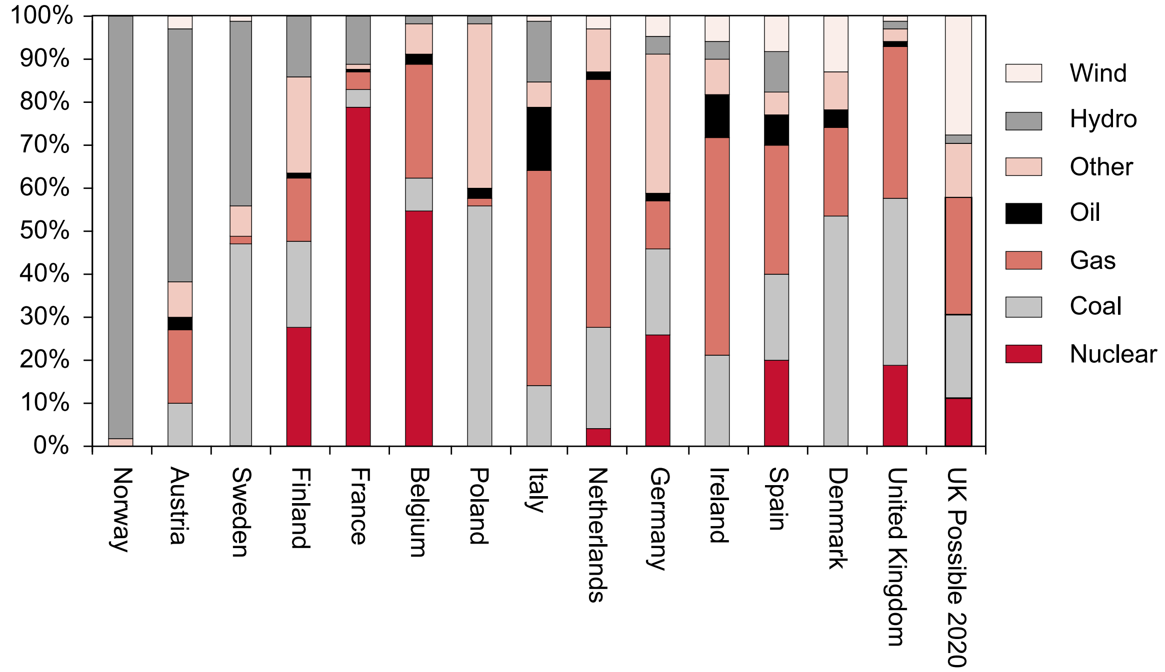
47. France and Italy generate respectively 12% and 15% of their electricity from renewables—much higher than in Britain—with the lion's share in both cases coming from hydroelectric plants. Germany generates 12% of its electricity from renewables, of which around two-fifths comes from wind power. Denmark and Germany are encouraging investors to re-power wind farms with larger turbines, which can increase output significantly without taking up more land.

48. A number of EU countries, including Belgium and Luxembourg and newer members such as Estonia, Lithuania, Hungary and Poland, generate less electricity from renewables than Britain.

49. Figure 5 shows the main sources of generation in a number of European countries. At the left are several countries with a very high share of hydro generation—the extreme case of this is the practically all-hydro system in Norway (not an EU Member State, but tightly integrated with the electricity industries in Denmark, Finland and Sweden). Most European countries generate the vast majority of their electricity from fossil fuels or nuclear power. The countries with the highest levels of wind generation are towards the right-hand end of the graph. The penultimate column shows the UK's generation mix in 2006, while the right-hand column indicates a possible mix that would allow the UK to meet a 15% target for renewable energy in 2020. This would require us to have a share of wind power more than twice as great as any European country achieved in 2006.

FIGURE 5

Generation sources in Europe, 2006



Source: Eurostat

"Other" includes lignite (particularly in Germany and Poland) and biomass (particularly in Denmark, Finland and Sweden)

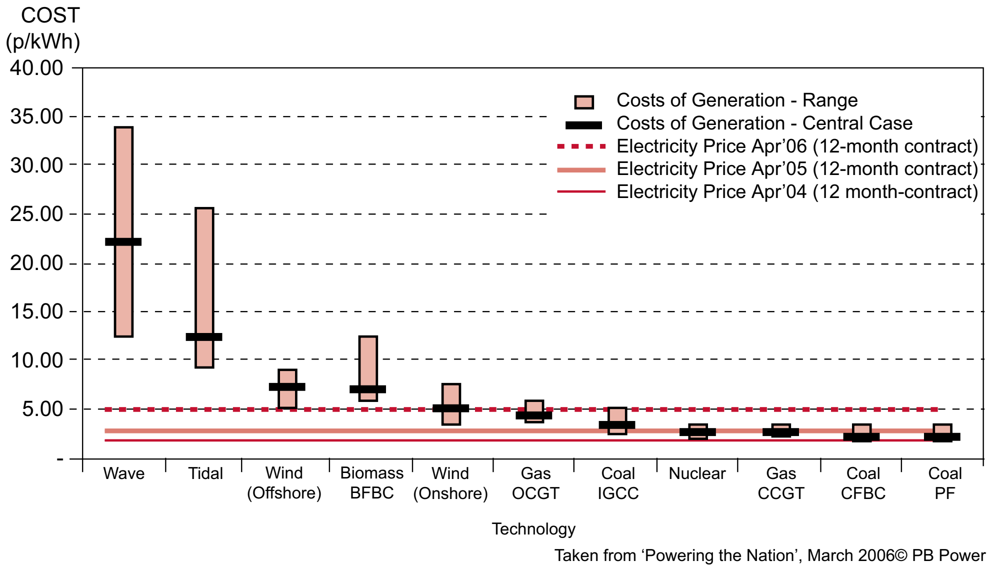
The base cost of electricity generation from renewable sources (excluding additional system costs, addressed in Chapter 4, and support costs, addressed in Chapter 6).

50. The first step in calculating the base costs of renewables is to calculate costs of generation at each type of plant. (As usually presented, these do **not** include significant additional system costs to provide back up for wind turbines when the wind is not blowing—or is too strong—or to reinforce the transmission grid. We deal with these additional costs in Chapter 4 below). The estimates varied considerably and most submissions gave little information on the assumptions underlying them. Most present a range of costs (Centrica p 102, E.ON p 109, British Energy p 242, Renewable Energy Foundation pp 46–47, Laughton p 387). Among the renewable technologies listed, onshore wind costs least—and in some cases its basic costs are almost as low as gas or coal-fired plants—partly because it is the most mature and developed technology. Off-shore wind is next followed by tidal, with wave power much the most expensive. We also received evidence (not shown in Table 2) that solar photovoltaics were expensive, with high capital costs (Ofgem Q 413, Energy Technologies Institute p 147). We did not receive estimates of the cost of generation from waste or landfill gas. The scope for expanding the latter is however very limited, as noted above. Most estimates show nuclear to have the lowest base cost of all forms of generation, although no station has been built in the UK for many years.

51. The cost of generation depends critically on the assumed capital cost of a power plant, the rate of return required by the generator, the cost of fuel (except for some renewable generators) and the amount of output that the plant is expected to generate (its load factor). Figure 6 below illustrates how different assumptions can lead to very different cost estimates, particularly for some technologies (Royal Academy of Engineering p 450, Institute of Mechanical Engineering p 373).

FIGURE 6

Costs of different types of electricity generation (excluding back-up and grid integration)



Key

Biomass BFBC—Biomass Bubbling Fluidised Bed Combustion

Gas OCGT—Open Cycle Gas Turbine

Coal IGCC—Coal Integrated Gasification Combined Cycle

Gas CCGT—Combined Cycle Gas Turbine

Coal CFBC—Coal Circulating Fluidised Bed Combustion

Coal PF—Pulverised Coal

52. Construction costs can vary for many reasons. For wind farms they vary from site to site. For example, different ground conditions can affect costs of cable lengths and the foundations of turbines (IET p 370). Copper and steel prices affect the cost of building wind turbines yet are extremely difficult to predict so a range is often used. The cost of land to build renewable projects also varies (IET p 370).

53. Financing costs vary depending on the perceived risk of the investment. Risks include engineering performance and changes in the regulatory environment. For the mature technologies, such as onshore wind generation, the performance risks are relatively low but are significant for newer technologies (IET p 371). The higher the assumed rate of return required by the generator, the greater the cost per year per MW of capacity. This effect will be particularly important for generators with high capital costs, such as nuclear stations and many renewable generators. Different companies will have different costs of capital—Shell told us that they had withdrawn from the London Array (a 1 GW offshore wind farm in the Thames Estuary) because the projected returns did not meet their investment hurdle rate (Q 348). But the company's partners, E.ON and DONG (a Danish generator), are continuing the project with Masdar, an investment fund for renewable technologies owned by the Government of Abu Dhabi.

54. The expected load factor and plant life will affect the capital cost per unit of output. This is particularly important for wind and marine generators, with few costs apart from capital costs. The higher the load factor, the lower the cost per unit of output. Possible sites for wind farms, for example, can be more or less windy and so have different costs per unit of power. The windier sites will have lower costs per unit of electricity generated as they produce more power with little or no increase in cost at the station. But many are remote from the main centres of demand and have higher costs of connection to the electricity system.

55. Between different biomass and waste plants, transport can be a substantial variable cost. Some plants are close to a ready supply of fuel such as woodchips from a wood processing plant. But those which take fuel from sources of waste or energy crops further afield will incur transport costs. They may also have to compete for alternative uses for the feedstock such as food production, or alternative biomass power plants (IET p 371).

56. For biomass, the UK's relatively small land area means that a heavy dependence would imply substantial imports, where costs could vary substantially depending on demand from other countries and international crop yields (IET p 371).

57. Finally, there is no commercial-scale generation of electricity from wave or tidal generators in the UK. Cost estimates for commercial-scale generation are extrapolated from small, often experimental, projects and accordingly have wide margins of error.

Inferring costs from feed-in tariffs

58. The cost estimates presented to us can be compared with the prices actually paid to renewable generators in Germany and Spain, where the authorities set feed-in tariffs—a form of subsidy used to remunerate renewable generators.[21] These tariffs can be expected to exceed the actual cost of renewable generation; and clearly there would be little or no investment if the tariffs were **less** than cost.

59. The system of tariffs used in Germany is complex. A wind farm at a site with good wind conditions receives a starting price for five years, and a lower basic price for fifteen. Both decline gradually in nominal terms during the life of the contract. This front-loads the support received by the generator, reflecting the dominance of capital costs. A wind farm at a site with less favourable wind conditions receives the starting price for longer, and may receive it for the entire twenty-year length of its contract. Sites with poor wind conditions are not eligible for support.

60. Between 2003 and 2006, the average amounts received by German wind generators varied between 7 and 7.25 pence per kWh.[22] Around 2,000 MW of capacity was added in each of the years 2004–2006. A revised tariff has been introduced for 2009 onwards, reflecting the higher price of steel, which has increased the cost of wind turbines (EWI pp 316–317).

61. In Spain, most wind generators have chosen to receive the wholesale market price plus a support premium, rather than a feed-in tariff. The premium is now adjusted so that the combination of the market price plus the premium has a floor of 5.7 pence per kWh and a cap of 6.8 pence per kWh.[23] Around 1,800 MW of capacity were added each year between 2004 and 2006, which doubled to 3,500 MW in 2007.

Comparing the cost of renewables with fossil fuel and nuclear power

62. One of the key questions is how the cost of electricity produced from renewable sources compares with that of power from fossil fuel or nuclear stations. When making comparisons, the different cost structures of each type of generation need to be borne in mind. Renewable and nuclear plants have high initial capital costs but most of their costs are then fixed (Royal Academy of Engineering p 445). The cost of electricity from fossil fuel power stations by contrast depends crucially on the volatile price of the fuel. For EU generators, the cost of carbon emissions permits (effectively a tax)[24] under the EU Emissions Trading Scheme will also be a factor. Long-run calculations of power generation costs

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21 We discuss the use of feed-in-tariffs as a policy measure in Chapter 6.

22 The original tariff range in Euros was 8.76 to 9.06 cents per kWh which was converted to sterling at an exchange rate of €1.25 to the pound.

23 The original figures were a floor of 7.1 euro cents per kWh, and a cap of 8.5 euro cents per kWh, again converted to sterling at an exchange rate of €1.25 to the pound.

24 The scheme requires companies to hold permits to emit carbon dioxide, which are traded and have a price, and the "tax revenue" is the value of these permits. If the Government auctions the permits, it gets to keep this tax revenue, but if it allocates them without charge to energy-using companies, those companies effectively keep the tax revenue.

therefore vary with estimates of the prices of fuel and the cost of carbon permits (IET pp 371–372).

63. Gas and oil prices, which have risen in recent years, are linked through indexation clauses in long term gas supply agreements in Europe. As the UK is now a net importer of gas and linked to the Continental gas network, gas prices in the UK tend to move with those in Europe. Coal prices depend more on the global market, and are also high, driven by demand in emerging economies and high oil and gas prices. The range of predictions of fossil fuel prices leads to a range of estimates of costs for electricity generated from gas and coal fired plants.

64. A modern gas-fired power station emits roughly 0.4 kg of carbon dioxide per kWh of electricity, while a new coal-fired power station should emit 0.8 kg per kWh. When deciding whether to build wind farms or conventional plants, the generator will include the cost of buying emissions permits for coal and gas-fired power stations—assuming that few permits, if any, will be allocated free of charge to the power sector after 2012. As emission permits are a policy measure to increase the cost of high-carbon generation, their price depends on government decisions on how many permits to issue.

65. The price premium of renewable over conventionally-generated electricity is reduced when the cost of fossil fuels rises. Witnesses who submitted evidence on the cost of renewable generation also gave estimates of the cost of electricity from fossil fuels and nuclear power. In these estimates, reproduced in Appendix 5, nuclear power is typically the cheapest form of generation. In most estimates, generation from coal or gas is cheaper than renewable power, although some evidence suggested that onshore wind generation could be as cheap as fossil fuels. We received some predictions of the costs of coal-fired stations with carbon capture and storage (CCS)—inevitably speculative since no commercial plant has been built—which were higher than the accompanying estimates of the cost of onshore wind.

66. We do not know the assumptions on fuel, carbon or construction costs, or interest rates, which underlie the estimates in Appendix 5. We have therefore made our own estimates (Table 2 below) of the cost of wind power and of the three main options, coal, gas and nuclear power, based on work done for the Government for its renewable energy consultation,[25] with the exception of our estimates of fossil fuel prices, where we took the actual prices paid in the twelve months to June 2008. During this period, the price of oil averaged $96 per barrel. The coal price was 0.74 pence per kWh (£54 per tonne) and the price of gas was 1.4 pence per kWh (40.6 pence per therm). We assumed that the thermal efficiency of a new coal-fired station (the fraction of its fuel converted into electricity) would be 45%, and that of a new gas-fired station 55%. For a biomass station, we used a fuel cost of 1.3 pence per kWh (£3.60 per GigaJoule) and a thermal efficiency of 28%. In the case

[25] Redpoint (2008) *Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes*. A report for the Department of Business, Enterprise and Regulatory Reform, June 2008.

of nuclear power, we take the cost of fuel per kWh of nuclear output from the Government's nuclear consultation.[26]

67. Table 2 shows that coal, gas and nuclear power have similar base generation costs, and that these are much lower than the cost of wind power (either onshore or offshore) and biomass. The cost of the three non-renewable forms of energy is around 4 pence per kWh, while the cost of onshore wind is 7 pence per kWh, and that of offshore wind 8 pence per kWh. Biomass generation is predicted to cost 9 pence per kWh.

68. The table divides the costs into capital costs—the cost of paying for the plant itself—and running costs, chiefly fuel and operations and maintenance costs. Four of our technologies—all except biomass and gas—have similar running costs in the region of one and a half to two pence per kWh. The high costs of wind generation are due to its much higher capital costs per kWh actually generated. Although capital costs per kW of **capacity** for onshore wind and coal are similar, costs for power actually generated by wind are much higher because of the relatively low operational availability of wind turbines. The running costs of biomass generators are high because they use a lot of fuel for each unit of electricity produced.

69. The second part of the table gives the key assumptions made in preparing these cost estimates. The power station's construction cost includes a local connection to the grid, but not the cost of any more distant reinforcement work required—as with intermittency, this is not a cost which the individual generator is asked to bear. We have used the same cost of capital for each technology, although generators might require a higher expected rate of return to invest in those perceived as more risky. The base case excludes the cost of carbon permits for coal and gas-fired plants.

70. The third part of the table shows what happens when we vary these key assumptions. The relative cost of coal, gas and nuclear plant might change, particularly if the cost of one technology was altered, but not that of the others. This might be most relevant for fuel costs, since fossil fuel prices have been more volatile than the cost of nuclear fuel. The penultimate line of the table includes the amount coal and gas generators would need to spend on carbon permits at a price of £20 per tonne of CO_2 (2 pence per kg),[27] given that the coal-fired plant would emit 0.76 kg of carbon dioxide per kWh it generated, and the gas-fired station would emit 0.37 kg,[28] while the other types of power station have practically no emissions. At this carbon price, nuclear power would be expected to cost less than coal or gas-fired generation. The final line includes the cost of carbon permits at £50 per tonne of CO_2—roughly the level ($85 per tonne of CO_2) recommended by the Stern Review of Climate Change.

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26 Department for Trade and Industry (2007) *The Future of Nuclear Power: The role of nuclear power in a low carbon UK economy*. Consultation Document, May 2007.

27 This is roughly the current price.

28 Gas-fired stations convert more of their fuel to electricity than coal-fired stations do, and gas contains more energy per tonne of carbon than coal does.

TABLE 2

Estimates of the cost of electricity *generation* in pence per kWh produced. These figures exclude the costs of backup conventional plant and grid integration, which are explored in Chapter 4

	Coal	Gas	Nuclear	Biomass*	Onshore Wind	Offshore Wind
Base cost (pence per kWh)[29]	4.1	3.9	4.5	9.0	7.3	8.1
Capital cost (pence per kWh)	1.9	0.9	3.0	3.4	5.5	6.0
Running cost (pence per kWh)	2.1	3.0	1.5	5.6	1.7	2.1
Key assumptions						
Construction cost (£ per kW of capacity)	£1,070	£523	£1,500	£1,837	£1,111	£1,574
Average output relative to capacity (load factor)	81%	81%	77%	80%	27%	37%
Plant life (years)	25	20	30	20	20	20
Interest rate	10%	10%	10%	10%	10%	10%
Fuel cost (pence per kWh of output)	0.74	1.38	0.44	4.6	0	0
Emissions of carbon dioxide (kg per kWh)	0.76	0.37	Nil at the station	Nil at the station	Nil at the station	Nil at the station
Base cost of electricity given:						
Assumptions above	4.1	3.9	4.5	9.0	7.3	8.1
Construction cost up 20%	4.5	4.1	5.1	9.7	8.4	9.3
Interest rate of 13%	4.6	4.1	5.6	9.9	8.4	9.5
Lifetime up by 25%	4.0	3.9	4.4	8.8	6.9	7.7
Load factor down by one-fifth	4.6	4.2	5.5	10.1	9.1	10.1
Fuel price up by 50%	4.9	5.2	4.7	11.3	7.3	8.1
Buying carbon permits at a price of £20/tonne CO_2	5.6	4.6	4.5	9.0	7.3	8.1
Buying carbon permits at a price of £50/tonne CO_2	7.9	5.7	4.5	9.0	7.3	8.1

* *specialised power plants burning biomass material (not energy crops)*

[29] Base cost equals capital cost and running cost. The numbers do not add exactly due to rounding.

71. On the basis of these figures, we estimate the average base cost of generation across the whole system with the current share of each type of output to be 4.3 pence per kWh. In the next chapter (Table 3) we use these figures to show how the total base cost of generation in Great Britain would change with different levels of renewable generation.

72. Of the variables in the third part of Table 2, only one, carbon permits priced at £50 a tonne of CO_2, would by itself make onshore wind competitive with coal, while offshore wind would remain slightly costlier; gas (and nuclear) would both remain cheaper than either form of wind power. An alternative hypothesis of, say, an increase of 50% in fossil fuel prices together with carbon permits priced at £20 a tonne, would bring the cost of coal- and gas-fired power close to that of an onshore wind station with a high (over 30%) load factor. Nuclear power would still be significantly cheaper (in the absence of changes to its own costs), and offshore wind and biomass generation would remain more expensive than electricity from fossil fuels.

73. We have not made our own estimates for other forms of renewable energy, or for plants with carbon capture and storage. There are only a few prototypes for wave and tidal power, and no commercial scale carbon capture and storage project exists. This means that cost estimates for these technologies can only be very tentative. We did not receive estimates for the cost of landfill gas or waste burning, which we believe to be cheaper than other renewables, but there is little scope to expand these.

74. All the cost estimates showed that nuclear power was cheaper than renewable energy. The cost of nuclear power is little affected by the oil price, although the uncertainty over the cost of decommissioning and waste disposal is a unique risk for nuclear stations. Nuclear plants have very low emissions and are not affected by changes in the cost of carbon. **We cannot consider renewable energy in isolation from the rest of the UK energy system and we support measures to include nuclear plants as an essential element of the UK's energy mix.**

75. **In summary, the cost of electricity from onshore wind farms at good locations would only be comparable with that from fossil fuel generators when prices of oil, gas and coal are very high or allowance is made for the price imposed for carbon emissions permits (effectively a tax). It is more expensive than nuclear generated power. In our base case, onshore wind cost 7 pence per kWh, as opposed to around 4 pence per kWh for the other technologies—coal, gas and nuclear. Offshore wind, biomass, wave and tidal power are even more expensive. And these estimates exclude the additional costs of integrating more renewable generation into Britain's electricity grid.** (These are outlined in Chapter 4.)

Future changes in the costs of renewable generation

Technology developments

76. Future developments in technology—such as advances in equipment design, manufacturing and installation—can be expected to reduce the costs of renewable energy significantly, as well as of some alternatives such as nuclear power. This is borne out by the long term trend of falling costs for onshore wind. But forecasting costs on the basis of these expected developments is far

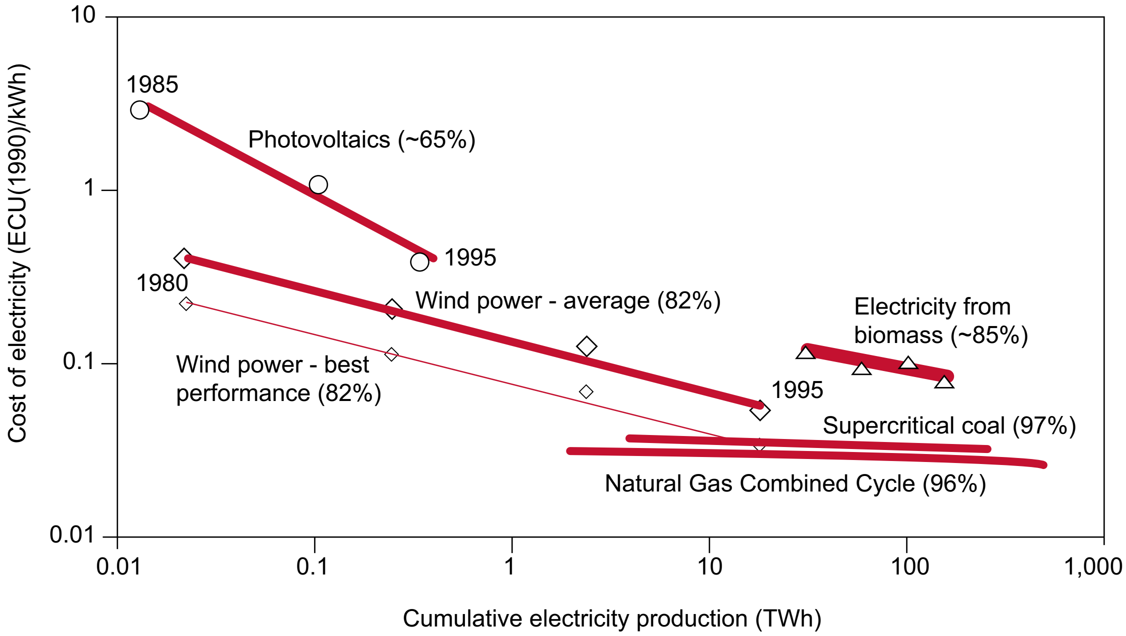
from a precise science. As a result it is only sensible to present a range of cost estimates.

77. Such estimates are nevertheless crucial in assessing the likely costs of renewable energy. The International Energy Agency has shown how the costs for various forms of renewable generation have fallen as more generators are built. The "learning curves"—which are the straight lines in figure 7 below—show how the cost per kWh of electricity produced by various technologies has fallen as the total amount generated by them has risen. For example, the top line in figure 7 below shows that over a period in which the cumulative output of photovoltaic power doubled, the cost of electricity from new installations fell to 65% of its level at the start of the period. In other words, unit costs fell by 35%. Total generation (or in other studies installed capacity), rather than the mere passage of time, appears to be the critical factor in reducing costs.

78. The steeper the learning curve, the more the costs have fallen as the amount of installed capacity increases. The percentages show what has happened to the cost of generation each time cumulative output doubles. So while the cost of solar photovoltaic power falls to 65% of its previous (very high) level, giving a reduction of 35%, the reduction in the more mature technologies of coal and natural gas combined cycle generation are much lower, at 3% and 4% respectively. These curves represent technical progress at the power station and take no account of possible improvements in technology to extract fossil fuels, which could also reduce costs.

FIGURE 7

Learning curves for types of renewable generation



Learning Curves for generation technologies

Source: International Energy Agency

79. Figure 7 shows straight lines but both axes use logarithms. Moving along each line from left to right means successively greater increases in cumulative output are required to give successively smaller absolute reductions in costs.

80. Studies cited by Dr Karsten Neuhoff found costs for various renewable technologies fall 10–20% as installed capacity doubles (p 196). This does not however mean that the fall in costs is smooth or constant. Cost reductions of wind farms have been interrupted in the last few years because of supply bottlenecks and/or fossil fuel and commodity price increases. These bottlenecks have led to higher prices for turbines coupled with long lead times. Similarly, all marine energy technologies, including off-shore wind, are competing with the offshore oil and gas industry for installation vessels and other equipment (Neuhoff p 197).

81. As a technology such as onshore wind power is more widely used, cost increases can still occur when investment rises. Similar increases caused by supply bottlenecks may also occur in other forms of renewable generation as they are rolled out (Neuhoff pp 195–196). There is also a shortage of engineers, scientists and skilled craftsmen (Royal Academy of Engineering p 445). Dr David Clarke of the Energy Technologies Institute said: "There is evidence that the capacity in the supply base is inadequate for what we currently need." He added: "If I talk to the marine power developers then they will most definitely cite shortage of skills in the marine industry from the point of view of dockside skills in terms of fabrication, assembly of very large structures" (Q 324). Neil Hirst, director for energy technology and R&D at the International Energy Agency also referred to industrial infrastructure as a factor in the different costs of renewable electricity generation in various countries: "In many cases you will find the costs are actually lower where the deployment is highest, simply because there is an industrial infrastructure for manufacturing and there is a learning by deploying elements which tends to bring costs down" (Q 394).

82. The cost of solar photovoltaics has followed a similar pattern. After three decades during which the cost was reduced by a factor of 100 (i.e. to 1% of its initial level), the price stabilised in the last four years, during which Government support for solar power in various countries led to a surge in demand and supply bottlenecks (Neuhoff p 196).

83. Once extra supply resolves these bottlenecks the cost of wind-generated electricity and solar power are expected to resume their downward trends. Dr David Clarke of the Energy Technologies Institute said of offshore and onshore wind: "There is real potential to drive down the cost from those systems to a level that is competitive with current centralised generation" (Q 309, Neuhoff p 196).

84. Wave and tidal generation costs are even more difficult to predict as the technology is at an early stage of development. So far many of the companies pursuing demonstration projects are small start-ups, focussed on getting the next round of funding for their first large-scale demonstration plant and showing that their concept has merit. Mass production that would reduce costs but seems far off and difficult to predict (Neuhoff p 196).

85. **Future developments in the base generation costs of electricity from renewable sources depend upon many variable factors such as technological development, the rate of return required by generators and construction costs. But from the evidence we have seen it seems clear that as things stand the base costs of generation of electricity from onshore wind are likely to remain considerably higher than those of fossil or nuclear generation and that costs of generation of marine or solar renewable electricity are higher still.**

Research to improve renewable energy technologies and reduce their costs

86. The Energy Technologies Institute (ETI) was set up to help sustainable low-carbon energy technologies become commercially viable. It is a 50:50 public/private partnership with BP, Caterpillar, EDF Energy, E.ON, Rolls-Royce and Shell. Each private sector partner will contribute £5 million a year for ten years, and the Government is prepared to match the contributions from up to 11 partners, giving a potential budget of £1.1 billion.

87. The ETI aims to:

(i) reduce greenhouse gas emissions

(ii) accelerate development and deployment of affordable low carbon technology solutions

(iii) increase security of energy supply in conjunction with greenhouse gas mitigation

(iv) increase the level and capacity of the low carbon skills pool—both in the UK and internationally

88. Investment in the UK has mostly been in research on novel technologies or in setting up full-scale systems ahead of commercial deployment. The important intermediate stages of development—technology integration and system demonstration—have been less well supported despite their importance in developing investor confidence. The ETI aims to help bridge this gap (p 146).

89. Offshore wind was cited as an area where research on improving the reliability of the wind turbines could reduce costs. Some wind turbines offshore had not been designed to cope well there (Clarke Q 310). Dr David Clarke, the Chief Executive of the ETI, said "The way to reduce the cost of those systems and to bring down the cost of the electricity generated in many cases is to improve the reliability and the operating costs of the machines themselves and then the systems, including the grid and the network infrastructure that is necessary to support those, whether it is gas or electricity. Those are the kinds of issues that we are seeking to address through the Energy Technologies Institute" (Q 308).

90. Research council spending on renewable energy projects has risen from £8.3m in 2000/01 to £30m in 2007/08. Solar power and fuel cell projects received over £6m each in 2007/08. Wind—which is a mature renewable energy technology—receives less than £1m (Research Councils UK p 441). This is only 1% of the Research Councils' total budget of £2.8 billion.

91. Dr Strachan of King's College London and the UK Energy Research Centre pointed out that some new technologies would not succeed. He advocated supporting a range of technologies with broad-based near-term support until it was clear which technologies were improving and which were offering cost and other advantages (Q 14).

92. This report is mainly about technologies in use or development. There are many other fields where basic or applied research might also yield practicable and cost-effective ways to help safeguard the environment and ensure reliable and secure supply of energy. Researchers, industry and Government can all play a part by remaining alert to the possibilities and flexible in their response. We list at Appendix 6 some potentially promising areas.

93. **We hope that the ETI's work will yield technological advance and lower costs. The Government should consider, perhaps in collaboration with others, offering a substantial annual prize for the best technological contribution to renewable energy development**. An initiative on these lines might help set the scene for a wider effort by the Government to encourage and promote research across on a range of technologies aimed at finding new and cost-efficient ways to reduce carbon emissions. We return to this theme in Chapter 6.

Noise, visual and other negative impacts of renewable deployment

94. There are widespread local objections to renewable generators—especially wind farms. These include:

(a) the visual impact of wind turbines (Campaign to Protect Rural England (Devon) p 252, Penk p 419, Jack p 374, Bishopton Village Hall Management Committee p 233);

(b) noise from the turbines and their potential impact on family life and health (Hadden p 325);

(c) effect on value of homes (Hadden p 325);

(d) economic impact on the community (Hadden p 325); and,

(e) perceived disregard for the opinion of rural communities (Hadden p 325).

Wind farms can also disturb wildlife (Two Moors p 492 and The Royal Society for the Protection of Birds)[30].

95. Most offshore projects would have less impact on local communities. But there are particular concerns about the proposed Severn Barrage. The Environment Agency in Wales said: "The estuary supports important habitats and a unique ecology which have strong protection under international law. The construction of a barrage would have significant impacts on the estuary, for example on wildlife, flood protection, navigation and the landscape."[31]

96. **Although their declared purpose is to improve the environment, it is clear that renewable energy installations can also have adverse environmental impacts which the Government should bear in mind as it weighs the benefits and costs of expansion of renewable generation**.

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30 See Royal Society for the Protection of Birds at http://www.rspb.org.uk/ourwork/policy/windfarms/index.asp

31 *Severn estuary barrage—a good idea*, Environment Agency Wales, 2006, available at: http://www.environment-agency.gov.uk/regions/wales/426317/1508205/?lang=_e

CHAPTER 4: RENEWABLES IN THE ELECTRICITY SYSTEM

97. This chapter considers issues affecting the electricity system as a whole if, as estimated in Paragraph 24, 30–40% of electricity is to come from renewable sources. The first is the problem of intermittency. Second, we consider the impact of different levels of renewable electricity on the overall cost of generation across the industry. Third, connecting renewable generators will require significant investment in the transmission and distribution systems. Finally, we consider the way in which these systems are operated, and the implications of power flows which may be more variable in future than at present.

Intermittency—a constant problem?

98. Matching electricity supply to demand is challenging as it is not presently economic, or technically feasible, to store electricity on a large scale. Electricity can be stored in batteries for portable applications but their costs are too high for use in the national electricity grid. Electricity generation must be matched to demand on a minute-by-minute basis, or power cuts result. Some power plants are therefore kept running at less than full load, to respond rapidly to a sudden increase in demand or to make up for a power plant failure elsewhere in the system. [32]

99. But not all power stations can be "dispatched" to change their output level quickly. Coal, gas- and oil-fired stations are generally straightforward though their response speeds vary. Nuclear stations are relatively inflexible, and are best operated at a constant (full) load. Renewable generators burning biomass, and hydro generators, can generally be dispatched.[33]

100. Wind, wave and tidal stations are inherently not dispatchable. They can only generate when conditions are right—if there is no wind, or too much wind, no electricity can be produced. Tidal generators can produce much more at the spring tides (with a high variation in the water level) than at neap tides (low variation). The tides are predictable far in advance, but the wind is almost impossible to forecast more than a few days in advance, and even day-ahead forecasts can be inaccurate.

Short term fluctuations

101. The first cost imposed by intermittency is that more plant has to be held in reserve to cope with short-term fluctuations in output. At present, National Grid, which operates the electricity system,[34] keeps a number of power stations running at less than their full capacity, providing about 1 GW of spinning reserve—that is capacity which can automatically respond to any

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32 The limited number of pumped storage stations in Scotland and Wales also increase output when necessary. They use electricity to pump water uphill, and release it when necessary to turn a turbine to generate power. But pumped storage carries an efficiency penalty, in that less electricity is generated at the end of the cycle than is required at the start. Nonetheless, it can be economic if the electricity used in pumping is cheap (which is typically the case overnight), and the water is released at peak times when power can be sold for a high price.

33 However, a hydro station may have to "spill" water if its storage is full and its generation is not required.

34 In Great Britain, the system operator is National Grid, controlling its own transmission system and those owned by Scottish Power and Scottish and Southern Energy. In Northern Ireland, SONI (System Operator for Northern Ireland Ltd) is a subsidiary of Northern Ireland Electricity.

shortfall in generation within seconds (Q 293).[35] The company also contracts with other stations to start generation quickly and has arrangements with industrial consumers to reduce their demand at short notice, in order to restore the level of spinning reserves as soon as possible after they are used. The company holds about 2.5 GW of this standing reserve (Q 293); 70% of this comes from generation, and 30% from industrial consumers (p 144).

102. As the amount of wind generation rises, the potential short-term change in wind output will also increase, and National Grid will have to hold more reserve to cope with this increase. The company told us that if renewables provided 40% of electricity generation—the share the company believes would be needed to meet the EU's 2020 energy target—its total short-term reserve requirements would jump to between 7 and 10 GW. Most of this would be standing rather than spinning reserves. This would add £500 million to £1 billion to the annual cost of these reserves—known as balancing costs—which are now around £300 million a year (Q 293). This is equivalent to around 0.3 to 0.7 pence per kWh of renewable output.

103. Estimates of balancing costs vary widely. The government has commissioned research from the consultancy SKM,[36] which estimated that if renewables provided 34% of electricity by 2020, with 27.1% from wind power, the extra cost of short-term balancing would be about 1.4 p/kWh of wind output[37] (Q 481). This equates to a total cost of £1.4 billion, well above that assumed by National Grid. Several pieces of evidence cited a 2006 report by the UK Energy Research Centre (UKERC),[38] which had estimated the balancing costs with up to 20% of intermittent renewable output in Great Britain at 0.2–0.3 pence per kWh. Although the share of renewables in the SKM study was less than double that of UKERC, the balancing costs per unit were more than five times higher. In part, this may reflect higher fuel costs since the studies surveyed by UKERC were performed; but it will also reflect the greater challenges of dealing with larger shares of intermittent renewable generation.

104. **Fluctuations in wind speed lead to short term changes in electricity output from wind farms. Greater use of wind power and other intermittent renewable sources therefore requires more backup generation capacity to respond very quickly to, for example, reductions in the output of wind turbines when the wind drops. But the technical challenges and costs of backup generation on a scale large enough to balance an electricity system with a high proportion of intermittent renewable generation are still uncertain.** There is currently no experience elsewhere in Europe of the scale of dependency on

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35 For the purpose of comparison current total generation capacity is 76 GW. The amount of spinning reserve that National Grid holds is currently based on the size of the largest single generator on the system. This allows the company to cope with any single failure, on the basis that the near-simultaneous failure of two large generators is sufficiently unlikely.

36 Sinclair Knight Merz (2008) *Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks* BERR Publication URN 08/1021

37 SKM presented these costs as 0.07 pence per kWh of **total** generation in a scenario with low levels of wind power (3.1%), and as 0.45 pence per kWh of **total** generation in a scenario with wind power making up 27.1% of total generation (table 7.12). We divided the difference of 0.38 pence per kWh by 27.1% to give the figure for the increased cost per kWh of wind generation.

38 Gross, R., P. Heptonstall, D. Anderson, T.C. Green, M. Leach and J. Skea (2006) *The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network*, London, UK Energy Research Centre.

intermittent renewables expected in the UK. **Whereas the highest share of intermittent renewable electricity now being generated is 15% in Denmark, the UK is expected to reach a share of some 30%–40%. We recommend that the Government should ensure that further work is carried out to clarify the costs and encourage development of technical solutions to deal with intermittency.**

105. Running a conventional plant at part load to provide spinning reserve reduces efficiency which leads to higher emissions per unit of electricity actually generated at that plant. Some commentators, such as Campbell Dunford of the Renewable Energy Foundation, argue that this might have offset the CO_2 savings from renewable generation in Denmark. Denmark's carbon emissions per kWh generated have fluctuated from year to year, although the trend is steeply downwards, as set out in Appendix 7. Calculations based on the loss of efficiency from running a power station at part load, and the amount of extra reserve required, also suggest that the extra carbon emissions in the UK from additional spinning reserve would be very small in comparison to the savings from renewable generation. The Government has estimated the net saving from raising the share of renewable electricity to 32% to be about 45–50 million tonnes of carbon dioxide—about 8–9% of total CO_2 emissions—after taking account of the cost of part-loading plant.[39] **The need to part-load conventional plant to balance the fluctuations in wind output does not have a significant impact on the net carbon savings from wind generation.**

Peak demand and capacity credit

106. The second cost due to intermittency comes from the need to have enough capacity available to meet peak demand. No power station is guaranteed to be available at peak demand. So the industry holds extra capacity over and above the expected peak demand to cope with stations that turn out not be available when most needed, or higher than expected demand. As a rule of thumb, a 20% margin of extra capacity has been sufficient to keep the risk of a power cut due to insufficient generation at a very low level, given the characteristics of the current system.

107. A fossil-fuelled station has around a 5% chance of not being available to generate at the time of the system peak because of breakdowns or essential maintenance (p 119). One plant's breakdown is rarely correlated with another. Nuclear plants have a similar risk, although they sometimes suffer from generic issues that require maintenance at all of the stations of a similar design.

108. But for renewables it is very different. At peak demand not only are the chances of a wind farm not being fully available much higher but it is very likely that, if so, nearby wind farms will also be at least partially unavailable because it is not windy in the area. This correlation will fall for distant wind farms—for example, the wind could well blow in Scotland when conditions in Cornwall are calm. But within the UK, the correlation does not fall to zero.

109. As a result, the proportion of renewable generation which can be relied on at peak demand is much lower than for fossil fuel plants and more complicated

39 Department for Business, Enterprise and Regulatory Reform (2008), *UK Renewable Energy Strategy;* Consultation Document, June 2008. The UK emitted 557 million tonnes of CO_2 in 2006.

to calculate. We received several estimates of how far wind capacity could be counted on to contribute to meet peak demand—its "capacity credit". BERR uses a range of between 10% and 20% of wind stations' capacity, so that 25 GW of wind plant could displace between 2.5 and 5 GW of conventional plant (Q 483). E.ON suggest that the capacity credit of wind power in the UK should be only 8% (p 119).

110. As wind generation increases, its capacity credit will tend to fall because low winds over part of the country can affect many wind turbines simultaneously. Extra, offsetting conventional plant is needed. The Renewable Energy Foundation's rule of thumb is to treat the square root of the wind capacity in GW as if it were conventional capacity (Q 112). On that basis, for example, 25 GW of installed wind generation capacity could be counted on for the same contribution to peak demand as 5 GW of conventional capacity; and it would take 36 GW of wind plant to match 6 GW of conventional plant.

111. Under any of these assumptions it is clear that much conventional capacity will be required to support renewable generators coming on stream in the period up to 2020, during which many of Britain's coal and nuclear power plants are scheduled to close. To replace them, the Government has calculated that 20–25 GW of new power stations will be needed by 2020—the equivalent of more than a quarter of today's 76 GW of electricity capacity. But that calculation assumes replacement on a like-for-like basis and does not take account of the target for renewables. **If some 30 GW of additional (Q 487) renewable capacity were required to meet the EU's 2020 target for the UK (and its capacity credit did not exceed 6 GW), a further 14–19 GW of new fossil fuel and nuclear capacity will still be needed to replace plants due to close and meet new demand. The total new installed electricity generating capacity required by 2020 would thus be roughly double the level needed if renewable generation were not expanded.**

112. The intermittent nature of wind turbines and some other renewable generators means they can replace only a little of the capacity of fossil fuel and nuclear power plants, if security of supply is to be maintained. **Investment in renewable generation capacity will therefore largely be in addition to, rather than a replacement for, the massive investment in fossil-fuel and nuclear plant required to replace the many power stations scheduled for closure by 2020. The scale and urgency of the investment required is formidable, as is the cost.**

113. The UKERC study calculated the cost of building additional conventional capacity to maintain reliability in Great Britain, with up to 20% of intermittent generation would be between 0.3–0.5 pence per kWh of that intermittent generation. These costs are dominated by the fixed costs of building plant and payments to generators to keep the capacity available even though they may rarely need to generate the power.

114. The SKM report for BERR estimated the cost of additional generating capacity to maintain security of supply with a renewable share of 34% would be £316 million a year, or 0.31 pence per kWh of wind output.[40] This

[40] SKM assumed that in a scenario with 27% of wind generation (and 34% renewable generation in total) 19.5 GW of conventional capacity would be needed but would not generate throughout the year, compared with 10.4 GW in a scenario with 3% of wind generation. The cost of the extra 9.1 GW of conventional

estimate is at the bottom of the UKERC range, because SKM assumed that the reserve capacity would have lower costs per kW than did UKERC.[41] If the studies had used the same cost of capacity, the SKM cost per kWh of wind generation would have been slightly higher than the UKERC figure, at 0.6 pence per kWh. This is because, as we have noted at paragraph 110, the capacity credit of each additional wind power station—i.e. the amount it can reliably contribute to peak electricity demand given the problems of intermittency—declines as more of them are added.

Storage—a permanent solution to intermittency

115. A sufficiently great advance in electricity storage technology would help solve many of the problems of intermittency (Q 98). If the storage could be charged and emptied quickly, this would be an attractive way of balancing the system. If the cost of storage capacity is sufficiently low, it would be an effective alternative to building additional generation capacity to deal with the peak levels of demand. The Royal Society of Edinburgh reported that a range of alternative storage technologies are being considered alongside the existing use of pumped storage hydroelectricity (p 453). Ofgem told us that fuel cells could become economically viable if their costs continued to fall, or electricity prices rose (p 171).

116. Dr Clarke of the Energy Technologies Institute told us more resources had recently been applied to developing energy storage, with major industrial corporations becoming involved. He pointed out that large-scale schemes might be located close to generators, and would then smooth out the load on the transmission system, reducing its costs. Small-scale storage could help to manage local demand. High-temperature batteries, mainly used by the military at present, are more efficient than conventional batteries, and could provide a significant opportunity where waste heat from combined heat and power schemes could keep them hot enough to work properly (QQ 318–20).

117. **A breakthrough in cost-effective electricity storage technology would help solve the problem of intermittency and remove a major stumbling block to wider use of renewable energy in the longer term. However, no evidence we received persuaded us that advances in storage technology would become available in time materially to affect the UK's generating requirements up to 2020. We recommend that the Government should as a matter of urgency encourage more research, development and demonstration in energy storage technologies.**

The impact on the system average cost of electricity generation of an increased share from renewables

118. Chapter 3 discussed the evidence we received on the cost of individual technologies for renewable generation. We now consider the total cost of generation across the system. This requires us to take account of the mix of capacity, the load factors that different plants achieve, and the costs of intermittency discussed in the previous section.

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capacity would be £316 million a year, which gives 0.31 pence for each of the 102 billion kWh of wind generation. (table 7.13)

41 UKERC based their estimates on a new Combined Cycle Gas Turbine plant costing £67 per kW per year, whereas SKM assumed that already existing plant could be kept open at a cost of just £35 per kW per year.

119. In Table 3, we use the figures in Table 2 to estimate the impact of increased renewable generation on base generation costs.[42] We assume that the amount of onshore wind generation rises from 2% to 8% of the total, and that offshore wind output rises to 19%. We assume that 75% of this extra renewable output would replace gas-fired generation, and 25% would replace coal. We find that if the share of renewable output rose to 34%, the base cost of generation would rise by £4.3 billion, or 1.1 pence per kWh of total output. We also consider a case with higher coal and gas prices—50% above 2007–8 prices. The increase in generation costs is somewhat smaller, at 0.8 pence per kWh or £3.0 billion.

TABLE 3

Prediction of the impact of increasing amounts of renewable power on the system average base cost of generation

	Current fuel prices		Fuel prices rise by 50%	
All figures use 2008 prices	Base cost in pence per kWh	Base cost in £ billion	Base cost in pence per kWh	Base cost in £ billion
Base cost of generation with current share of renewable output (6%)	4.3 p/kWh	£16.2 billion	5.2 p/kWh	£19.6 billion
Base cost of generation with an additional 5% onshore and 13% offshore wind (25% renewable in all)	5.0 p/kWh	£18.6 billion	5.6 p/kWh	£21.2 billion
Base cost of generation with an additional 6% onshore and 19% offshore wind (34% renewable in all)	5.4 p/kWh	£20.5 billion	6.0 p/kWh	£22.6 billion

120. The SKM study[43] cited by government witnesses also predicted a sizeable, but lower, increase in generation costs.

Investment in the Electrical Grid

121. National Grid told us that capital investment to reinforce the onshore transmission networks—the wires and pylons that carry electricity over long

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42 We have followed the Government's consultants in assuming that the capital costs of generators will fall slightly over the years to 2020—if we were to assume constant costs over the period, the additional cost of renewable generation would be higher by about £500 million a year.

43 Sinclair Knight Merz (2008) *Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks* BERR Publication URN 08/1021 SKM estimated the average base cost of generation in 2020 with 6% of renewable output would be 4.68 pence per kWh. If the share of renewable output rose to 34% the average base cost of generation would be 5.19 pence per kWh. This gives an increase of 0.51 pence per kWh of total output, or £1.9 billion, which in turn implies that the base cost for each kWh of renewable output is about 2 pence higher than the base cost of the kWh of conventional output it replaced. Our figures are based on Table 2, which predicts offshore wind to cost roughly 4 pence per kWh more than coal- or gas-fired electricity.

distances—to accommodate 40% of renewable generation would cost around £3.5 billion. This included reinforcements to the transmission network to accommodate an additional 10 GW of renewable generation in Scotland, developments in Eastern England to accommodate up to 19 GW of offshore wind generation in the North Sea and an overhead line in mid-Wales to accommodate an extra 1 GW of onshore wind generation (p 127 and appendix 2; Q 267).

122. These figures cover only the cost of upgrading the onshore transmission system. Laying cables along the sea bed to connect offshore wind farms will be expensive. National Grid expected the cost for the 19 GW of offshore wind—which it views as necessary if the EU 2020 targets are to be reached—to be in the region of £6–10 billion (Q 271). To connect 33 GW of offshore capacity to the Grid, Ofgem expected a cost of around £10 billion which is at the more optimistic end of National Grid's range of costs. Any of these figures would be well above the amounts for local connection costs included in the estimates of power station costs presented in Chapter 3.

123. National Grid's figures did not include the costs of improving local distribution networks that may be necessary in some areas to connect up the new generators. In areas where renewable resources are plentiful, the distribution system is often sparse, and new generation will trigger significant infrastructure investment, in many cases including the construction of new overhead lines. The Energy Networks Association described the provision of infrastructure to accommodate 2020 targets as challenging (p 285).

124. The SKM study cited by the Government estimated £10.2 billion would need to be spent in total on the transmission and distribution networks. That is at the low end of National Grid's range of estimates, despite the fact that SKM have included distribution costs. But SKM's figures apply to 34% of electricity coming from renewables while National Grid's are estimated for a 40% share.

125. SKM calculated these transmission and distribution costs would add a further 0.34 pence per kWh to the cost of the renewable scenario, or 1.25 pence per kWh of wind generation. Added to the other costs outlined earlier for balancing and security of supply the renewable scenario would be 27% more expensive than the conventional scenario, at 6.17 pence per kWh as opposed to 4.86 pence per kWh.

126. Table 4 gives our own estimates of the total cost of moving to a high level of renewable electricity generation in 2020. The top line of the table gives the predicted base cost of generation in 2020, on the assumption that there is no further increase in the share of renewable generation, taken from Table 3. The second line includes the cost of system balancing and consumers' payments for the existing transmission network. The third line gives our prediction for the total costs of generation and transmission in 2020, with 6% of renewable power.

127. The rest of the table considers the additional costs imposed by increasing the share of renewable generation. First, there is the higher base cost of renewable generation, from Table 3, which would add £4.3 billion. Second, there are the costs of system integration—additional balancing and reserve costs, and extra investment in the onshore and offshore transmission networks. We use the middle of the ranges given to us by National Grid for balancing and transmission costs, and the upper end of the UKERC range

for reserve costs. These add £2.5 billion to the predicted cost. In total, increasing the share of renewable generation to 34% would raise the annual cost of generation and transmission by £7.5 billion. In other words, the cost of generation and transmission would rise from 4.7 pence per kWh of total output to 6.7 pence per kWh.

TABLE 4

Predicted total costs in 2020 of electricity generation and transmission with 34% of generation from renewables, including allowance for back-up and grid integration

	Pence per kWh of **total** output	£ billion per year
Predicted base generation cost with 6% renewables	4.31 p/kWh	£ 16.2 bn
Cost of balancing and existing transmission system	0.41 p/kWh	£ 1.5 bn
Predicted total cost with 6% renewables	4.82 p/kWh	£ 17.7 bn
Extra costs of moving from 6% to 34% renewables		
Generation base cost	1.14 p/kWh	£ 4.3 bn
Predicted additional costs of system integration		
Intermittency (See para 102 and 113)	0.33 p/kWh	£ 1.3 bn
Transmission (See para 121–3)	0.32 p/kWh	£ 1.2 bn
Predicted total integration costs	0.65 p/kWh	£ 2.5 bn
All extra predicted costs for moving from 6% to 34% renewables	1.79 p/kWh	£ 6.8 bn
Predicted overall cost of generation and transmission with 34% renewables	6.61 p/kWh	£ 24.5 bn

128. **Our calculations suggest that the total extra annual cost of increasing the share of renewables in electricity generation from 6% to 34% in 2020 would be £6.8 billion or an extra 38%—the equivalent of an extra £80 a year for the average household. Emissions of carbon dioxide would be reduced by 52 million tonnes a year—in 2007, the UK's emissions were 544 million tonnes. This implies that the additional cost is about £130 per tonne of carbon dioxide emissions avoided.**

Grid connection policy

129. The current policy is for each project developer to arrange a separate connection between an offshore generating plant and the electricity network

on land. Ofgem is required to seek the best route forward through competition and markets wherever appropriate, and to secure value for money for consumers. They and BERR have decided to base future arrangements around competitive tenders for the major offshore transmission projects. (QQ 442–443, p 171).

130. National Grid and EDF agreed that this "radial connection" approach was fit for purpose when the decision was made. But the need to develop renewables offshore had changed significantly since then. They questioned whether this approach could be sustained for an offshore wind programme of three times the size originally envisaged. The proposed regime appeared overly complex to National Grid, with many areas still uncertain and undecided. The company believed simple, co-ordinated, regulated transmission build would be more effective to help ensure the infrastructure was in place when new renewables were ready to connect. Ofgem said if it transpired that they needed to develop an offshore grid, rather than taking a radial approach, they would not rule it out.

131. **We note that the regulator's statutory duties require the use of competition wherever appropriate, and therefore give it some discretion about the use of markets. Although competition is usually preferable, we are concerned that the use of competitive tenders implies a piecemeal approach to building the networks of wires and cables required to connect offshore wind farms to the electricity grid, and that as a result the programme could become overly complex and costly. We recommend that the regulator implements the new system in a way that allows a coordinated approach for organising grid connections to offshore wind farms.**

Grid charges and access

132. A second set of transmission-related issues concerns the terms on which renewable generators are able to access the grid. First, renewable generators in some parts of the country (and particularly in Scotland) face significant delays before they can be connected. In the face of insufficient transmission capacity, National Grid's response has been to delay connecting generators to the system, rather than to connect them and ration capacity (e.g. through market prices) when required. Second, there will be times when the grid cannot accept all the power generated within an area, and generators will be unable to sell their power. Third, we received some evidence querying whether the charges levied for using the transmission grid are appropriate.

Delays in Grid connections

133. National Grid has signed agreements with 49 GW of new generation since 2005, equivalent to nearly two-thirds of the 77 GW of capacity currently connected to the system. This has created a backlog for getting projects connected to the Grid. National Grid has established the "GB queue", which promises to give generators access to the grid in the order in which they signed connection agreements with the company. But new entrants may receive a connection date in ten years' time, according to Scottish and Southern Energy (p 85).

134. Ofgem and BERR have recently concluded a Transmission Access Review, which asked National Grid to take a more proactive approach to managing this queue, giving priority to projects that had received planning permission

for their plant. Ofgem told us that National Grid is now taking a more robust approach to removing unviable or purely speculative projects (p 171). **We welcome these measures to organise better the queue of renewable generation projects awaiting connection to the electricity grid. They should reduce delays in connecting viable generation projects and push back schemes unlikely to get off the ground.**

Surplus power

135. When National Grid is unable to accept power from a generator, through a lack of transmission capacity, it has to compensate the generator accordingly. But as wind output grows, flows on the transmission system will become more variable. British Energy pointed out that at very high levels of wind-generated electricity, there may be periods when it will be necessary for National Grid to instruct wind generators to spill power because renewable generation exceeds demand, net of other plants that are required to run. National Grid's policy at present is to invest in a way that keeps the cost of transmission constraints at about £100 million a year. They noted that without additional investment on the lines between Scotland and England, the cost of constraints might rise to between £500 million and £1 billion a year. This would cost a household consuming the average amount of electricity between £7 and £14 a year.

136. It is important that the transmission companies strike the right balance between investing in transmission and paying stations to be constrained off (p 311). It would not be economic to build a network in which transmission constraints were very rare, as the capacity needed to achieve this would cost too much. For an analogy, a motorway with six lanes in each direction might never see a traffic jam, but it would be a better use of resources to build a three-lane motorway and accept a few hours of congestion each month. A two-lane road that was congested for several hours a day would be inadequate, however. If the electricity transmission companies do not invest enough in the grid, congestion costs will be excessive; the cost of inadequate capacity is not a traffic jam, but that the system operators may have to use expensive stations near the loads rather than cheaper stations further away. Transmission access arrangements should address this issue. A series of proposals are outlined in Appendix 8. The key feature is that if new generators in areas likely to have a surplus of power must pay more to use the grid, they will tend to avoid these areas, reducing the amount that needs to be spent on transmission investments.

Transmission charges and losses

137. The Transmission Use of System charges are set by National Grid to recover the costs of all three transmission system owners in Great Britain. Generally, the more remote a generator, the higher the charges it has to pay because of the greater investment required in the transmission network to carry the electricity to centres of high demand. So a wind farm in the Highlands faces higher charges than an identical one near London. However, Professor Bain argued that the transmission charging system did not take account of the electricity lost in transmission (p 227). While these losses are only equal to 2% of electricity generated on average (p 144), they rise with the distance that power has to travel (Q 291). Furthermore, when power flows increase, the marginal losses are twice the average level. National Grid's Seven Year

Statement[44] shows that an extra 100 MW of generation in the Highlands would only replace 90 MW in the Midlands, as a result of the additional transmission losses incurred. In 2002, Ofgem proposed that transmission losses should be taken into account in the industry's trading mechanisms, but was over-ruled by the Government.

138. The Government was concerned about the impact on the costs of renewable generators located in Scotland. The higher the cost, the greater the financial support required (cf. chapter 6). If the system of support gives similar payments to every generator (of a given type), then the costs of the most expensive generator deemed to deserve support (the marginal generator) determine the payments to each of them. If the marginal generator is located in Scotland, then charging for transmission losses would increase the amount of support it required, and raise the amount of profit made by those generators in areas with lower transmission losses.

139. In the broader context, E.ON told us that charging for use of the transmission system should continue to reflect the costs to the system associated with generating from renewables and other generation at that location on the system. This would help ensure that these costs are taken into account in the decision where to site the project in the first place (p 108). But Scottish and Southern Energy, which has wind farms in remote parts of Scotland, argued against "the current perverse mechanism of regional charges". Ofgem has successfully defended a judicial review on the basis that "it was absolutely right that people who were at the extremities of the system should pay very high charges that reflected the economic costs of transmitting electricity a long way from where it is produced to where it is used" (Q 422). We agree with this position. **We consider that the current system of Transmission Use of System charges sends broadly appropriate signals of the costs of locating generators at different points on the system.**

Mitigating intermittency by more connections to the Continental grids

140. Over the long term the costs of intermittency could be mitigated by greater interconnection between the electricity grids of Britain and the rest of Europe (p 56, Q 20). Unlike Denmark, for example, Britain has very little capacity to import or export electricity to other countries. There is a link to France with 2 GW of capacity. National Grid and the Dutch transmission operator are building a cable to the Netherlands with 1 GW of capacity, expected to cost £480 million. Three other lines—to Belgium, Norway and the Republic of Ireland—have been studied, but no contracts have been signed. Even if all three were built, the total import capacity would be roughly 6 GW, compared to our peak demand of over 60 GW. Britain is, in effect, an 'island generator'. This complicates the task of managing intermittent generation.[45]

141. Greater inter-connectedness would allow Britain to tap renewable sources over a wider area which would reduce the problems with intermittency. For example, when the wind is blowing in Denmark but not Britain, electricity from Danish wind farms could then be imported. The wider the area of

[44] National Grid, *Seven Year Statement*, May 2008, table 7.5

[45] Spain, however, is in a similar (or worse) situation to the UK, in that its link with France allows it to import only about 1 GW of power, but has successfully integrated 15 GW of wind capacity, meeting 10% of demand. (p 464, para 13, plus European Transmission System Operators fttp://www.etso-net.org)

interconnectedness, the more likely it is that variations in wind patterns will cancel out, although the weather may sometimes be similar over even a wider area. For example, we received some evidence that low wind speeds in the UK could coincide with similar conditions in Germany, Ireland and even as far away as Spain.[46] Furthermore, it would not be economic to build enough interconnector capacity to solve our problems with intermittency, for wholesale electricity prices in the UK and on the Continent would then converge, whereas the interconnectors need different prices in the two markets to profit from trading between them. **Greater interconnector capacity with the Continent would reduce, but not solve, the problems of intermittent renewable generation.**

46 The Renewable Energy Foundation sent us a copy of a paper on this issue: Oswald, J., M. Raine and H Ashraf-Ball (2008) "Will British weather provide reliable electricity?" *Energy Policy*, vol. 36, no. 8, pp 3212–3225

CHAPTER 5: RENEWABLES FOR HEAT AND TRANSPORT

142. Most of the debate on renewable energy has focussed on electricity generation. This chapter considers renewable sources for the two other main uses of energy—heat and transport, which together account for roughly 80% of the UK's final energy consumption.

Heat

143. Renewable heat sources could make a significant contribution to reducing carbon emissions, according to a number of submissions. Scottish Power believe renewable sources of heat have "significant undeclared potential" while Philip Wolfe of the Renewable Energy Association said this area had been "neglected" (Scottish Power p 646, Philip Wolfe Q 175).

144. There are four main renewable sources for heat:

(a) Biomass

Biomass heat comes from the burning of organic matter with wood the most common source. Biomass heat is often generated on the site where it is to be used from households to intermediate industrial use but it can also be distributed through district networks or grids.

(b) Biomethane

Some types of biomass can also be used to produce 'biogas'—a mixture of methane and carbon dioxide—through anaerobic digestion, which turns the material into compost in the absence of oxygen. Removing the carbon dioxide leaves bio-methane. Akin to natural gas, bio-methane can be pumped through the gas networks or grid to customers. Such systems are already used in Sweden and Switzerland. Injecting bio-methane into the gas network effectively reduces the carbon intensity of gas.

(c) Heat pumps

Heat pumps work by first compressing a liquid or gas which naturally heats it, allowing the heat to be used to warm a building. The liquid or gas is then allowed to expand, releasing heat as it cools down (which could be used in air-conditioning or refrigeration). The resulting cooler liquid or gas is circulated via a pipe next to a natural source of warmth, either in the ground or the air. The cooler liquid or gas will absorb heat from the warmer surroundings until it reaches the same temperature. The process is repeated by compressing the liquid or gas again. The heat already absorbed by the liquid or gas reduces the amount of compression needed to reach a given temperature. This allows heat pumps to generate considerably more energy in heat than they consume in electricity, so they are regarded as renewable sources.

Ground source heat pumps extract the energy absorbed from the sun. A few metres below the ground, the earth keeps a constant temperature of around 11–12 degrees centigrade through the year. A length of pipe is placed in the ground through which a combination of water and anti-freeze is pumped to absorb the heat from the ground. Ground source heat pumps can transfer this heat from the ground into a building to provide space heating and, in some cases, pre-heating domestic hot water. For every unit of electricity used to pump the heat, 3–4 units of heat are produced, according to the Energy Saving Trust.[47] Some systems can be run in reverse to provide cooling in hot weather.

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[47] Energy Saving Trust factsheet on Ground Source Heat Pumps available at: http://www.energysavingtrust.org.uk/uploads/documents/myhome/Groundsource%20Factsheet%205%20final.pdf

(d) Solar thermal

Solar thermal panels use the energy from the sun for heating. These have been found to be most cost-effective when they produce 50–70% of a household's average hot water requirements, according to the Government's recent renewable energy consultation paper.

Combined Heat and Power

145. Combined Heat and Power (CHP) captures and uses the waste heat produced during generation of electricity and so can lower carbon emissions. It tends to work best at community level on residential developments rather than in individual houses. Some industrial firms also use CHP. But since in Britain CHP is mostly derived from fossil fuels, it is not a renewable source of energy. The Government's consultation paper on renewable energy nevertheless sees potential for renewable forms of CHP using biomass and biogas.

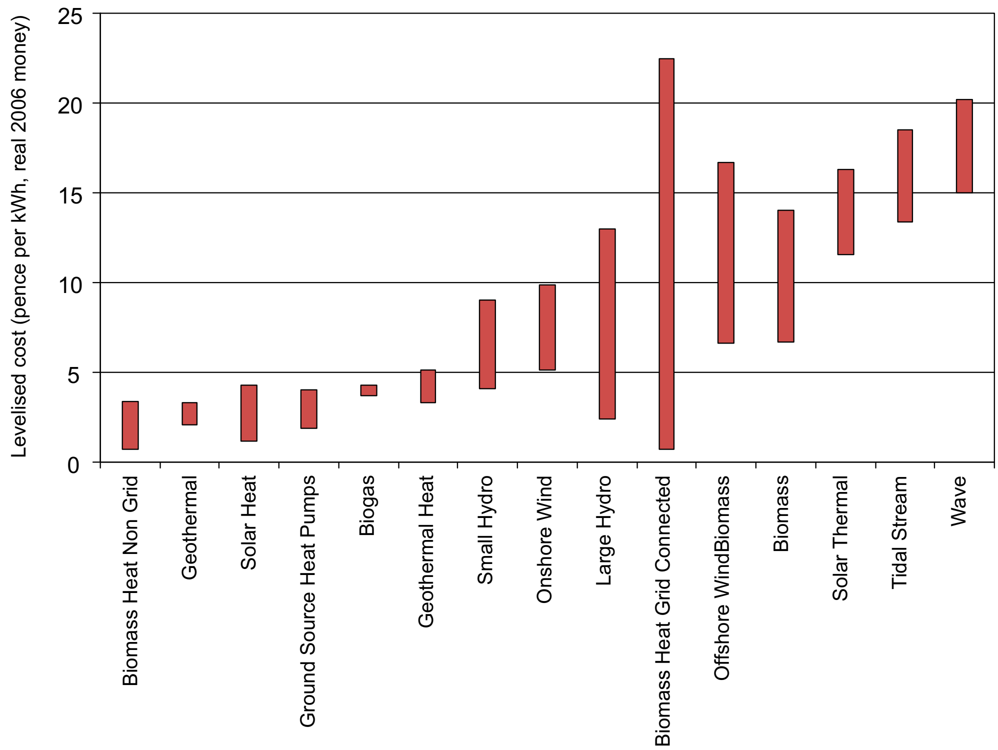
Costs surrounding greater deployment of renewable heat technologies

146. The Government stated in its consultation paper that biomass heat was "one of the most cost-effective potential sources of renewable heat", while Scientists for Global Responsibility argued: "Biomass can be used directly for heating—e.g. wood pellet boilers or domestic wood burning stoves—at low cost" (Scientists for Global Responsibility p 459).

147. Figure 8 shows small scale biomass heat—i.e. not connected to a grid for wider distribution—to be comparatively cheap. But the chart also shows that for larger scale biomass heat projects, which might well need to be connected to distribution grids, the costs range from relatively low to expensive. The wide range is due to the different costs of various biomass fuels and their high transport costs depending where they are sited. Biogas projects have a very small cost range and are only slightly more expensive than small-scale biomass heat.

FIGURE 8

Levelised project cost ranges at 2006 prices by the Pöyry energy consultancy group



148. Biomass and bio-methane are normally generated from locally sourced feedstock. But widespread deployment of biomass would require imports, with relatively high carbon emissions from transport. Both biomass and bio-methane may also use energy crops which compete with food crops for arable land.

149. Centrica cautioned: "More work needs to be done on the economics and supply chain risks of biomass, especially where it is produced from specifically grown crops (albeit it is less critical when using existing waste). This is a new commodity, global demand is likely to increase dramatically, and as such its future price and availability are extremely difficult to predict" (Centrica p 95).

150. Some bio-methane production could come from waste and sewage, with the added benefits of capturing the greenhouse gas methane and avoiding the need for incineration (National Grid p 145).

151. A report commissioned by the German government in 2007 on possible European biogas strategies found that EU-produced bio-methane has the potential to replace roughly 50% of EU natural gas imports from Russia by 2020. This highlights the potential for bio-methane injection into the gas network on a large scale (National Grid p 145).

152. But there are technical issues—in particular whether the bio-methane meets UK gas quality requirements; and the expensive equipment needed to inject bio-methane into the grid, so that large-scale deployment is required for economic viability (National Grid p 145).

153. Heat pumps, which are already widely used in parts of continental Europe, were favoured in a number of submissions as a good source of renewable energy (Renewable Energy Foundation p 327, EDF p 271, Mayer and Bentley p 399). The Pöyry chart shows they are only slightly more expensive than small-scale biomass heat. But heat pumps also consume some electricity, as already indicated at paragraph 144(c).

154. Other barriers to greater use of smaller scale renewable heat technologies include lack of familiarity among households, unsuitability for flats, and high up-front capital costs, although operating costs for heat pumps are lower and could lead to lower household energy bills (Renewable Energy Foundation p 327).

155. EDF favours heat pumps over biomass for "delivering low carbon heat as biomass supplies are limited and the transport of large volumes of biomass into urban environments is problematic" (EDF p 271).

156. Solar thermal heating is a high cost option compared to other forms of renewable heat as shown on the Pöyry chart. A good solar thermal system can provide around 50–70% of a dwelling's hot water demand and with more panels around 30% of its space heat demand (Genersys p 311).

157. The Government has estimated that 14% of heat would need to come from renewable sources if Britain is to hit the EU's proposed target of 15% of all energy in Britain coming from renewables by 2020. At present only 1.2% of heat comes from renewable sources. Biomass and heat pumps are the most cost-effective ways of increasing the share of heat from renewables, as shown in Figure 8. The Government expects they would make up the lion's share of any renewable heat deployment in the near term. But supplying enough biomass and heat pumps to ensure 14% of heat came from renewables by

2020 would be extremely difficult. So more expensive sources such as solar thermal and biogas might be used to reach the 14% target. The Government is considering ways to encourage renewable heat generation such as mandating energy companies to supply a proportion of heat from renewable sources, or requiring suppliers to pay generators of renewable heat an above market price. We note that the Secretary of State for Energy and Climate change stated on 16 October that he would soon make further announcements on the role of renewable heat.[48]

The costs of renewable heat compared to electricity

158. Some witnesses argued renewable heat should be making a greater contribution towards meeting Britain's carbon emission targets. Campbell Dunford of the Renewable Energy Foundation said the "low hanging fruit" of renewable heat was being missed because "everybody is fixated with the holy grail of generating electricity [from renewable sources] at a micro and a macro level" (Q 115). Philip Wolfe of the Renewable Energy Association said: "The heat sector is still largely ignored and its contribution can be as large as electricity. The cost of producing renewable heat, the incremental cost, is substantially lower than the incremental cost of producing renewable electricity and it has been estimated that one could achieve the same carbon savings in renewable heat for about a third of the cost of the same carbon savings in renewable electricity." He suggested that it had appeared to be easy to design policy for the small number of large electricity generators, whereas renewable heat would come from a large number of small plants (Q 175).

159. The Pöyry chart (figure 8) shows that various heat technologies such as biomass and heat pumps have lower costs than those for electricity such as wind generation. But solar thermal heat and the top end of the range for biomass heat connected to the grid are relatively expensive.

160. A number of witnesses argued that it was more cost-effective to use biomass for heat than for generation of electricity (Renewable Energy Association p 424, Centrica p 95). The Government's recent consultation paper on renewables also assessed the use of biomass for heat as more cost-effective in terms of pound per tonne of carbon abated than for electricity.

161. EDF argued that the key question when comparing the costs of renewable heat and electricity technologies was whether the marginal technology in the electricity sector—which they argued was likely to be offshore wind—requires more or less subsidy than the marginal technology in the heat sector. EDF expects heat pumps to be the key form of low carbon heat. EDF's analysis indicates that a heat pump, which can be retrofitted to a conventional hot water and radiator heating system in an existing property, would require less subsidy per kWh of renewable energy produced than an offshore wind farm. But the heat pump's cost per tonne of CO_2 abated is considerably higher because it runs on electricity, which itself involves carbon emissions. In the long term an increase in electricity generation from renewables might increase the carbon saved by heat pumps (EDF p 280).

162. Renewable heat can also help avoid costs associated with intermittency of many forms of renewable electricity generation such as wind farms. Heat can

[48] Hansard, 16 October 2008, col 936.

also be safely and easily stored, unlike electricity (EDF p 280, Genersys p 311).

163. **Harnessing renewable sources of heat is often cheaper than for electricity generation and it offers a larger target area, as heat accounts for two-fifths of final energy demand in the UK, as opposed to around 20% for electricity. Unlike wind power—the dominant source of renewable electricity generation and the renewable source to which the Government has paid most attention—there is no intermittency problem with renewable heat. We recommend that the Government should lay at least as much emphasis on encouraging the development and use of renewable heat as on renewable electricity generation.**

Transport

164. For transport the main alternative source of energy to fossil fuels is biofuels.

(a) Biofuels

Biofuels can be made from a range of organic materials including oilseeds, wheat and sugar, and are typically blended with conventional petrol and diesel. At present the two main types of biofuel are biodiesel and bioethanol. Biodiesel, a diesel substitute, is generally produced from oily feedstocks such as rapeseed, sunflower or palm oil, or from recovered cooking oil. Bioethanol, a petrol substitute, is generally produced from starchy feedstocks, such as wheat, sugar beet or sugar cane—although it can be produced from any organic substance such as wood, grass or municipal solid waste. Bioethanol and biodiesel can simply be added to existing liquid fossil fuels and at low percentages require little or no changes to either the vehicles or the fuel infrastructure. Other forms of biofuels include biomethane, which is a gas produced by the biological breakdown of organic matter and can be used as a renewable alternative to natural gas, either as a transport fuel or for electricity generation and heating.

(b) Electric and plug-in vehicles

Small cars powered by electricity through a battery rechargeable from the electricity mains are now available. Due to their limited power the current range is seen as suitable only for short daily journeys. For more general use, the plug-in hybrid, which has sufficient battery capacity charged from the mains supply for most daily use, with a small internal combustion engine able to provide power on extended journeys, may be more promising. Plug-in hybrids are to be marketed by US and Japanese manufactures in the near future (Scientists for Global Responsibility p 459).

(c) Hydrogen vehicles

Hydrogen fuelled vehicles are still being researched and may be a renewable technology of the future. Two types of hydrogen powered vehicles are possible. One uses hydrogen as the fuel for an internal combustion engine. The second uses hydrogen in fuel cells which when combined with oxygen is turned into electricity to power the vehicle. Most hydrogen today comes from non-renewable sources such as natural gas. But it could in theory be produced in a renewable way through electrolysis which splits water into hydrogen and oxygen. Transport for London has signed a contract to have 10 hydrogen fuelled buses operating in the capital by 2010 after trials.

165. The Government in April introduced a requirement that 2.5% of fuel sold in British forecourts must come from renewable sources.[49] The European Commission has proposed that 10% of energy for transport in each EU member state come from renewable sources by 2020.[50] The appeal of biofuels was outlined by the Royal Academy of Engineering: “Biofuels … can simply be added to existing liquid fossil fuels and at low percentages require little or no changes to either the vehicles or the fuel infrastructure. It is likely that the ease of adding biofuels to road transport fuel is one of the main reasons that governments … have introduced targets for their introduction” (Royal Academy of Engineering p 445).

Costs and carbon emissions

166. Biofuels have been controversial as some of them appear to have little impact on reducing carbon emissions—the key aim of all renewable energy. The Royal Academy of Engineering explained that in theory biofuels should be zero carbon. As with other plants, energy crops—which are used to make biofuels—absorb CO_2 as they grow. When the energy crop is burned or processed the CO_2 that has been absorbed during the plant’s growth is then released. In theory, the amount of CO_2 released should be the same as the amount absorbed during the plant’s growth making the process carbon neutral. But in practice there will often be more CO_2 emissions from fertiliser production and as biofuels are processed, so that they do not provide zero carbon energy. In some cases these emissions can “render the biofuel almost pointless in terms of carbon savings” (Royal Academy of Engineering p 445). Furthermore, soil degradation can occur where single energy crops, such as oil palms, replace rain forest. This is “ultimately unsustainable”, according to the Royal Academy of Engineering, and results in the loss of crucial carbon sinks—areas of soil which can store large amounts of carbon that have previously been absorbed by the rain forest (Royal Academy of Engineering p 445).

167. Today’s commercially produced biofuels are made from the parts of plants that could otherwise have a food use, such as wheat grain, beet or cane sugar, or vegetable oil. In the production of bioethanol or biodiesel, very little of the plant is actually converted into the fuel with most of the plant discarded (Royal Academy of Engineering p 445).

168. The Gallagher Review commissioned by the Government expressed concerns about the impact on people in developing countries from agricultural land and food crops being used for biofuels.[51] It concluded that: “The introduction of biofuels should be significantly slowed until adequate controls to address displacement effects are implemented and are demonstrated to be effective. A slowdown will also reduce the impact of

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[49] The Government initially planned to increase the share of fuel sold in forecourts coming from renewables to 5% in 2010–11. But in July the Government decided to consult on whether this should be slowed down to reach 5% in 2013–2014 in line with the recommendations of The Gallagher Review of the *Indirect Effects of Biofuels*, July 2008.

[50] The target does not cover transport energy from oil products other than diesel and gasoline, and therefore means that aviation (which uses kerosene) is excluded, although it is included in the denominator of the 20% EU target for the overall use of renewable energy.

[51] The Gallagher Review of the *Indirect Effects of Biofuels*, July 2008, which can be viewed at: http://www.dft.gov.uk/rfa/reportsandpublications/reviewoftheindirecteffectsofbiofuels.cfm

biofuels on food commodity prices, notably oil seeds, which have a detrimental effect upon the poorest people."

169. Second generation biofuels are manufactured from waste, residues such as straw and whole plants not suitable for food. So they should offer greater benefits, using about one third of the land and lower other inputs. But they are still emerging and not yet available on a commercial scale (Scientists for Global Responsibility p 459).

170. Others argued that many of the first generation of biofuels lead to sharp reductions in greenhouse gas emissions compared to fossil fuels. The Renewable Energy Association argued: "Many current generation biofuels produced in the UK can deliver significant greenhouse gas savings entirely sustainably. For example, British Sugar has announced that its sugar beet-to-ethanol plant in Norfolk delivers a 71% saving against fossil petrol, and Argent Energy delivers an 83% saving against fossil diesel at its tallow-to-biodiesel plant in Motherwell" (Renewable Energy Association p 424).

171. Yet the cost of obtaining reductions in carbon emissions from biofuels was far higher than for renewable sources of electricity and heat. A study by Pöyry for the Government modelled the most likely mix of renewables in electricity, heat and transport sectors to meet the EU's proposed targets that 15% of all of Britain's energy and 10% of transport fuels come from renewables in 2020. The study also estimated the costs and the reduction in carbon emissions in the electricity, heat and transport sectors over the lifetime of the renewable projects.[52] From these figures, Pöyry calculated the cost of reducing each tonne of carbon dioxide emissions over the lifetimes of the renewable projects in each sector—known as the lifetime abatement costs—as shown in Table 5. This differs from earlier cost tables in the report which show the cost per unit of energy. The estimated cost of reducing carbon dioxide emissions by one tonne using biofuels for transport was £189—more than 5 times the average cost of using renewable sources of electricity and heat.

TABLE 5

Cost estimates of carbon reduction using renewable energy sources

	£/tonne of CO_2 abated [53]
Electricity and Heat	36
Transport	189
Weighted average	46

Source: Pöyry Energy Consulting, Compliance costs for meeting the 20% renewable energy target in 2020

172. In transport there are few renewable options other than biofuels. Electric and hydrogen powered vehicles, described in paragraph 164, both use electricity. They can only count as renewables if they use renewable sources, and, as we

[52] Lifetime costs and emissions figures cover periods beyond 2020. For example, a wind farm built today to help meet the EU's proposed targets will most likely continue to operate after 2020 incurring costs and reducing carbon emissions.

[53] The figures were originally in euros:—Total Renewable Energy Sources €57, Electricity and Heat RES €45 and Transport RES €236. These figures were converted at an exchange rate of €1.25 to the pound.

have seen, renewables still only account for around 5% of total electricity. But if, for example, wind farms generate a larger share of electricity in future, electricity generated during periods of low demand, such as the early hours of the morning, could be stored in the batteries of electric cars (Q 223).

173. **We share the concerns raised in the Gallagher Review about existing biofuels. We consider that steps should be taken towards developing second generation bio-fuels as soon as possible. Until the costs of carbon emissions reduction through biofuels come down we recommend that the Government should not seek to increase further the use of biofuels.**

CHAPTER 6: POLICY ON RENEWABLE ENERGY

174. This chapter considers a range of policy issues relevant to renewable energy. We cover the role of renewable energy in UK energy policy, the justification for supporting it, and the best means of doing so. We also comment on micro generation, the impact on consumers' bills, support for technology development and the planning system. Finally, we ask whether the proposed 15% target for UK renewable energy by 2020 is achievable, and if so, at what cost.

The role of renewable energy in UK energy policy

175. In July the Government published its consultation on a UK Renewable Energy Strategy. The Secretary of State for Business, Energy and the Regions (BERR) wrote that "Renewable energy is key to our low-carbon energy future" The UK already has a legal commitment to the EU's target that 20% of Europe's energy should come from renewable sources by 2020, within which the proposed UK target is a renewable energy share of 15%. The (then) Minister of State for Energy told us that "decisions on renewable energy cannot be made merely on the basis of cost in the short term; it is about tackling climate change and securing energy supplies for the future. The Stern Review into the economics of climate change was absolutely clear that we need to invest now or pay a higher price later" (Q 472).

176. The then Minister said we needed a suite of policies. Diversity in our energy sources was important. The more energy the UK produced for itself, the better for security of energy supply. Civil nuclear power should play a role, although public spending would not subsidise it. The earliest a nuclear power station could be built was 2017–2020 (QQ 476, 477, 479, 480). Fossil fuel generation was also important, for diversity and for operation of the network, and because it could come on stream faster than nuclear power; development of carbon capture and storage (CCS) would be important to reduce emissions. It was hoped that a Government-funded CCS demonstration project would be operating by 2014.

177. **It is clear that, although the cost of the technology for carbon capture and storage (if and when it becomes a practical possibility) is inevitably highly speculative, it will always be more expensive than large-scale carbon-based energy without CCS.** Retrofitting the technology to stations not designed for it might be particularly expensive, but would be necessary to have a significant impact on the very large volume of emissions from existing plant.

178. We note that the Government has announced arrangements to charge a fixed unit price for disposal of some nuclear waste and spent fuel, and some respondents to a recent consultation on this issue expressed the view that this might provide a potential subsidy to nuclear power.[54] While the Government rejects this view, and we would not argue for a nuclear subsidy, we are conscious of the anomaly that the Government publicly supports a subsidy for renewable energy but not for the other main source of low-carbon energy.

54 BERR (2008) *The Government Response to the Consultation on Funded Decommissioning Programme Guidance for New Nuclear Power Stations*, September 2008, para 4.3.

179. Other witnesses had a range of views on the place of renewables in the Government's energy policy. Professor Paul Ekins told us that renewables could contribute to the objectives of carbon reduction and energy security. He believed that the government was currently "giving most attention to the reduction of carbon emissions, but energy security is coming up fast on the inside track and may indeed overtake it at some point" (Q 3). Malcolm Keay of the Oxford Institute for Energy Studies argued that renewables had had very little impact on the UK's carbon emissions so far and were unlikely to make a significant impact by 2020. Much of the reduction in emissions in Britain had come from replacing coal with gas-fired plants in the 1990s. Countries with very low carbon electricity systems had a combination of nuclear and hydroelectric generation (Q 82). Mr Keay saw a danger that uncertainty over Government policy on renewable energy might deter needed investment in new conventional generating capacity, with some risk of power shortages, or, more likely, increased carbon emissions from running on old plant. If the capacity was then replaced in haste with new gas-fired plant, the renewables policy might increase the risks to the UK's energy security (Q 88).

180. Professor Gordon MacKerron saw a potential trade-off between objectives: policies designed to counteract climate change were nearly always good for security,[55] while policies designed to be good for security, such as more use of coal, were not always good for climate change. Renewables added diversity to the UK's energy portfolio, and reduced pressure on world fossil fuel markets. The real difficulty for the Government would be to retain public support for difficult choices in meeting emissions targets (Q 248).

181. The Renewable Energy Foundation told us that renewable generation had to fit in with the rest of the system, where new conventional plant would contribute to emissions reduction through better thermal efficiency. If renewable investment did not support conventional generation, the money would be "wasted". Renewable energy policy should also devote more attention to the heat sector, where solar thermal and ground source heat pumps could make a big contribution (Q 114).

Government intervention in the energy market

182. Cost comparisons between renewable and conventional electricity generation are complex and depend on many variables. But witnesses generally agreed that renewables are more expensive.

183. **It seems clear there would be little investment in renewable energy without substantial Government support and that a 15% target would not be met without it.**

184. Professor David Newbery told us that the context for renewable policy was a world in which some countries were tackling carbon emissions through the most obvious and direct way of pricing them, but some countries were not going to be part of the carbon pricing system. Support for renewable energy therefore helped to develop low-carbon technologies to the point where they might be commercially viable and adopted abroad (Q 184)

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55 We infer that he was talking of energy security in the medium-term sense of being able to rely on adequate supplies of fuel, since large amounts of intermittent renewable generation can make it harder to maintain the minute-by-minute availability of electricity.

185. The then Minister of State for Energy told us that in Phase III of the EU Emissions Trading Scheme, people were projecting a carbon price of about €35 per tonne of CO_2 (£28 per tonne at current exchange rates), whereas a price of somewhere between €100 and €200 per tonne would be required to develop renewables through that mechanism alone. The Minister did not think that this gap reflected a weakness in the trading mechanism, and agreed that it indicated that renewables were a high cost means of achieving reductions in CO_2 emissions. Over time, he expected costs of renewables to come down (QQ 473–475).

186. Many companies told us that even if the present level of carbon and fossil fuel prices were enough to cover the cost of onshore wind power, there was no guarantee these prices would continue, so that there was no sound basis for investment without additional support.

Support mechanisms and their costs

187. The most direct mechanism used by the British Government is Renewables Obligation Certificates (ROCs), which replaced a Non-Fossil Fuel Obligation. ROCs require electricity suppliers to deliver a set proportion of power from renewable sources. Generators receive one ROC for every 1,000 kWh of renewable electricity generated, and can sell these to suppliers. A supplier unable to surrender ROCs equal to the set percentage must pay for each missing certificate into a buy-out fund which is then redistributed amongst the suppliers who surrendered ROCs. The market price of ROCs rises above the buy-out price if a shortfall is expected, for each ROC allows the holder not only to avoid paying the buy-out price, but also to share in the money paid in by those with a shortfall. The design of the Renewables Obligation effectively means that the total payment to renewable generators, over and above the market price they receive for their power, should be fixed. A fuller description of the Renewables Obligation is at Appendix 9. The equivalent mechanism in use in Germany is the feed in tariff, which guarantees a price to the producer. In both cases, the extra cost is passed on to the consumer.

188. Witnesses expressed a range of views on the relative merits of the schemes. Some saw the RO rewarding the least capital intensive technology (Renewable Energy Foundation Q 123).The overall cost in Britain was seen as less but the feed-in tariff in Germany has produced more renewable energy at lower unit cost (Ekins Q 11). There is some convergence between the two systems as the UK introduces banding of the RO, which will give some technologies more than one ROC per 1,000 kWh, while some countries are changing feed in tariffs from a fixed total payment to a fixed supplement to the market price (IEA Q 399). Power companies valued a stable investment framework and generally preferred to retain the RO in the British market (Scottish and Southern Energy, Centrica Q 241; E.ON p 108). A number of witnesses however supported the adoption of a feed-in tariff for small scale generation (Friends of the Earth Q 60; Keay Q 96).

189. **We note the evidence that the cost per kWh of renewable electricity supported by the Renewables Obligation has been significantly higher than the amounts paid via feed-in tariffs abroad, and that much of the excess has been due to other differences in the environment for renewable generation, particularly in the planning system.** The renewables support mechanisms have already gone through a number of

changes including the banding of the Renewables Obligation to give different levels of support to different forms of electricity generation. Introducing feed-in tariffs at this stage for large-scale generation[56] would create more uncertainty and risk deterring investment in the sector. **Given investors' need for a predictable framework, it seems right to retain the Renewables Obligation, if it is desired to continue increasing generation of electricity from renewable sources.**

190. The EU Emissions Trading Scheme (ETS) also supports renewables by putting an additional cost on emitting carbon. Every EU Member State has allocated allowances to electricity generators and companies in some industrial sectors, and each allowance gives the holder the right to emit one tonne of carbon dioxide. Should individual generators or companies need to emit more than this, they can buy extra permits from groups who did not use up all their carbon allowances. So far, most permits have been allocated without payment, but because every tonne of carbon dioxide either requires the generator to buy a permit or to forgo the opportunity of selling a spare permit, the scheme raises the marginal cost of generating power from fossil fuels. This raises the price of power, creating an incentive to invest in low carbon or renewable forms of energy by tagging a cost on to carbon emissions.

191. The Government has also operated a separate UK-only emissions trading scheme for large companies and public sector organisations that are not heavy emitters of carbon. The UK Emissions Trading Scheme was launched in 2002 and operated in a similar way to its EU counterpart. The scheme ended in 2006 and a replacement, the Carbon Reduction Commitment is being developed. The new scheme will place an emissions cap on up to 5,000 large business and public sector organisations.[57]

192. The Climate Change Levy is a tax on the use of energy in industry, commerce and the public sector, with offsetting cuts in employers' national insurance contributions and additional support for energy efficiency schemes and renewable sources of energy. The aim is to encourage users to improve energy efficiency and reduce emissions of greenhouse gases through greater use of renewables. Fuels used by the domestic and transport sectors and to generate electricity are exempt from the levy, as is energy used by charities or very small firms. Climate Change Agreements allow energy intensive businesses to receive an 80% discount from the levy, in return for meeting energy efficiency or carbon saving targets.

193. The Carbon Emissions Reduction Target (CERT)[58] requires gas and electricity suppliers, each with over 50,000 household customers, to achieve targets for a reduction in carbon emissions generated by the domestic sector. Ofgem, which administers the CERT, checks whether suppliers' schemes will result in an improvement in energy efficiency and therefore a reduction in carbon emissions.

194. Finally, the Renewable Transport Fuels Obligation introduced in April requires 2.5% of the petrol and diesel sold in forecourts comes from

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[56] On 16 October the Secretary of State for Energy and Climate Change announced his intention to introduce feed-in tariffs for small-scale generation, complementing the Renewables Obligation.

[57] House of Commons, Written Ministerial Statement by Hilary Benn, Secretary of State for Environment, Food and Rural Affairs: Update on the Carbon Reduction Commitment—16 July 2008

[58] This follows on from the Energy Efficiency Commitment which was run in a similar way to the CERT.

renewable sources or biofuels. The obligation will rise to 5% by 2010. If petrol companies do not meet the renewable obligation they have to buy out the balance of their obligation at a price set by the Government. This has been set at 15p per litre until 2010. Biofuels also pay 20 pence a litre less tax than petrol or diesel.

195. Table 6 gives estimates of the current annual cost of these various support schemes. These costs are likely to rise significantly as the level of renewable energy increases in future. Most are borne by energy consumers, rather than by taxpayers. Renewable generators receive around £1¼ billion a year from increased electricity prices caused by the Renewables Obligation, Emissions Trading Scheme and Climate Change Levy, mostly from consumers. Taxpayers fund the Research Councils, £30 million a year on renewable energy research, and the Environmental Transformation Fund, about £130 million a year on grants to renewable generators and farmers growing energy crops. The amount that the Energy Technologies Institute (part-funded by taxpayers) will spend on renewable energy has not yet been announced; nor the proportion of the Carbon Emissions Reduction Target that will be spent on microgeneration. The total support for renewable generation, from taxpayers and from energy consumers, is now of the order of £1.4 billion a year.

196. We can only estimate the cost of support for renewable transport fuels. In 2007, the duty rebate on biofuels cost the taxpayer £100 million, but these comprised only about 1% of road transport fuel. In the first three months of the obligation, biofuels provided 2.6% of road transport fuels, and the annualised cost would have been correspondingly higher. Since fuel suppliers have chosen to meet the target for biofuels, this must imply that the cost of doing so (net of the rebate) is less than the buy-out price of 15 pence per litre. The change in the cost (and hence price) of fuel will be between zero and £200 million in 2008/9.

TABLE 6

Support for renewable energy

Scheme	Description	Cost	Paid by
Renewables Obligation	Electricity suppliers must buy a proportion of their sales from renewable generators, or pay a buy-out charge	£874 million in 2007/8 [a]	Electricity consumers
EU Emissions Trading Scheme	Renewable generators indirectly benefit from the increase in electricity prices as other companies pass the cost of emissions permits into the price of power	Perhaps £300 million in 2008, given current permit prices [b]	Electricity consumers
Carbon Emissions Reduction Target	Energy companies must install low-carbon items in homes, which could include microgeneration from 2008	Total cost will be £1.5 billion over 3 years—most spent on energy efficiency	Gas and electricity consumers

Scheme	Description	Cost	Paid by
Renewable Transport Fuel Obligation	Fuel suppliers must supply a proportion of biofuels or pay a buy-out charge	No more than £200 million in 2008/9 [c]	Consumers
Climate Change Levy	Electricity suppliers need not pay this tax (passed on to non-domestic consumers) on electricity from renewable generators	£68 million to UK generators; £30 million to generators abroad in 2007/8	Taxpayers, via reduced revenues
Lower fuel duty for biofuels	The rate of fuel duty is 20 pence per litre below that for petrol and diesel	£100 million in 2007	Taxpayers, via reduced revenues
Environmental Transformation Fund	Grants for technology development and deployment, including subsidies for installing renewable generation, planting energy crops and developing biomass infrastructure.	£400 million over three years from 2008/9	Taxpayers
Research Councils	Grants for basic science research	£30 million in 2007/8	Taxpayers
Energy Technologies Institute	Grants to accelerate development (after the basic science is known) of renewables and other energy technologies	Allocation (and eventual size) of budget not yet announced.	Taxpayers and sponsoring companies

a This is the buy-out price multiplied by the size of the obligation. Source: Ofgem

b Permit prices are currently about £19/tonne CO_2, and coal-fired generators are normally setting the electricity price, passing 0.9 kg per kWh through to consumers

c This upper limit is set by the buy-out price of 15p per litre—if the extra cost of biofuels (net of the fuel duty rebate) is more than this, companies will opt for the buy-out instead.

Micro generation

197. Witnesses' views on micro generation of energy by households and businesses varied. For micro-generated electricity, the Renewable Energy Foundation said: "We see the costs as astonishingly high and the gains as very modest." As a result the organisation felt that any policies requiring a certain amount of micro-generated electricity would "only drive in sub-optimal technologies at enormous expense" (Renewable Energy Foundation p 45).

198. The Government supports micro-generation for reasons other than economics. Former energy minister Malcolm Wicks said: "If we were just focusing on the economics, we probably would not want to look seriously at micro-generation [but] many concerned citizens are asking how they can personally make a difference" (Q 503). **We are not persuaded that the wish of concerned citizens to make their own contribution to emissions reduction is an adequate justification for a public subsidy to micro-generation.**

199. Energywatch accepted that micro-generation had "a high cost for a modest contribution to fuel saving and emissions reduction" (p 294), but supports the introduction of a feed-in tariff for small scale renewables as it could attract new investment, change the balance between consumers and energy companies, stimulate energy-reducing behavioural changes and alleviate fuel poverty. This last benefit was contingent on mechanisms such as installation subsidies to ensure that low-income consumers could benefit from the technologies, particularly in hard-to-treat properties (pp 294–297).

200. While Professor MacKerron described micro-wind generation for individual urban households as a "dead duck" he argued there was potential for the micro-generation of electricity for blocks of flats. He called for improvements to the grid and distribution system to enable the sale of micro-generated electricity. The grid was originally designed to carry electricity from large power plants **to** homes and businesses. But the system needs to be adjusted to be able to take more easily micro-generated power **from** households and businesses as well, said Professor MacKerron (QQ 254–255).

201. When people approach the power suppliers they find themselves "bogged down in a set of tariffs [that]require a PhD and an awful lot of time to work out which of the suppliers is offering you the best deal", according to Stephen Smith, managing director of networks at Ofgem. The regulator is working with the industry to simplify the arrangements for micro generation. It argued micro generators needed a one-stop shop to provide advice and suggested that the Government should fund an existing price comparison web site to do this (Ofgem QQ 448–449).

202. While the economics of micro-generated electricity appear dubious, especially at the individual household level, the potential for the micro-generation of heat is much greater. Much of the technology for generating renewable heat is at the household level. As was shown in Chapter 5, the cost of renewably generated heat is relatively cheap compared to electricity, and it avoids the problems of intermittency.

203. The Renewable Energy Foundation—which was very sceptical about micro-generated electricity—argued in favour of measures to boost micro-generated heat. While they argued that the sector would not need much help Campbell Dunford, chief executive, said: "We believe that measures to encourage the take-up of heat saving and heat generation measures within the household are fundamentally good" (p 52, Q 133).

204. **The returns from micro-generated electricity look too small and uneconomic for the Government to support. But the gains from households using micro-generated heat look much more promising. Government policy should focus instead on households generating renewable heat and on schemes that use renewable heat on a larger scale, such as those covering a housing development, or group of public buildings.**

Fuel bills

205. The Committee are very conscious of the high cost of energy—driven mainly by the record oil prices reached this year—and its impact on the heat and electricity bills of households and businesses. Support for renewable energy increases costs further. Alistair Buchanan, chief executive of Ofgem, said: "One of the features of the renewables strategy is that of a £1,000 bill

currently for the average household, £80 is environmental connected" (Q 413).

206. Energywatch estimate that the current Renewables Obligation—which is only one of the support mechanisms for renewables—will cost households an extra £33 a year by 2020. But this is based on the scheme only delivering 20% of electricity from renewables. If the EU targets are to be met, with relatively small contributions from heat and transport, many expect 30–40% of electricity to have to come from renewables with greater costs to consumers.[59] With this in mind, Energywatch called for measures to help low-income households deal with the likely extra costs (Energywatch p 290).

207. The Church of England's House of Bishops Europe Panel were concerned that higher energy prices arising from renewable energy would lead to more people facing fuel poverty[60] (p 349). Alistair Buchanan, chief executive of Ofgem, told us that for every 1% increase in power prices 40,000 people were added to the fuel poor lists (Q 413). Given that he had calculated that environmental measures were raising prices by 8%, this would place an extra 320,000 people in fuel poverty.

208. **On the evidence submitted to us, renewable electricity is clearly more expensive than fossil fuel-fired and nuclear generation and leads to higher energy bills for consumers and businesses. We estimate that a household which consumes the average amount of electricity will have to pay in 2020 about £80 extra a year. The Government will need to take this on board in framing its policies towards fuel poverty, noting the high correlation between fuel poverty and poorly-insulated homes.**

Support for the development of renewable energy technology

209. The then Minister told us that the Government believed renewable energy could create thousands of business and employment opportunities, and that the Government was committed to ensuring that many of these jobs were created in the UK (Q 472).

210. The IEA told us that the costs of Danish wind power were amongst the lowest they had looked at, because learning by doing had brought the cost down. Denmark's strategic decision 20 years ago to develop wind energy meant that their wind turbine manufacturing industry was now a world leader (QQ 394–398). China was by far the leading country in thermal solar

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59 We set out the additional costs of renewable electricity in Chapter 4. The Renewables Obligation exists so that renewable generators can recover the difference between their base costs and prices in the electricity wholesale market. In Appendix 9, we estimate that the Renewables Obligation, or equivalent schemes, will cost an average household £50–£60 a year in 2020. Higher charges from National Grid for transmission and system operation, to cover the cost of integrating renewable generators, will cost an average household £30 a year. This does not include the benefits renewable generators get from not having to buy carbon permits. Renewable generation will have little impact on the amount by which emissions trading raises the price of power, since this works by changing the prices charged by coal- and gas-fired generators. As long as the number of permits available is adjusted to reflect the amount of renewable output, renewable generation will not affect these prices. Electricity bills also cover the existing distribution and retailers' costs—these would be hardly affected by the growth of renewable generation. For an average household electricity bill of £400 an extra £80 represents a 20% increase—smaller than the 38% increase in the cost of producing the electricity.

60 Fuel poverty is defined at the household level as needing to spend more than ten per cent of income (after tax and benefits) on heating and lighting to achieve an acceptable standard of comfort.

heating for domestic water, developing a huge industry and a low-cost technology with millions of installed systems (Q 408).

211. The ETI saw an opportunity to use the UK to demonstrate technological and engineering developments and sell capability worldwide (Q 326). The UK also had the potential to develop a renewable power industry: Vestas Wind Turbines, on the Isle of Wight, sells every turbine blade it produces to the United States (Q 330).

212. It would help the UK meet the EU renewable target if the supply chain for renewable energy were to be developed. But this is unlikely to lead to an overall increase in employment, as the number of jobs in the UK depends on conditions in the economy as a whole. People who might gain jobs in renewable energy would normally have been able to work in a different sector, possibly more productively,[61] had renewable energy not been expanded.

213. The Committee heard that a much greater research and development effort is needed on renewables and other measures to cut carbon emissions. Professor Paul Ekins of King's College London argued for the equivalent of twin Manhattan projects—the scientific research programme which developed the atomic bomb. One would enhance energy efficiency, the other promote energy supply technologies including renewables. In his view, countries need to work together on this research. He said: "It is terribly important that we get globally the biggest bang for our buck and have properly coordinated basic scientific research." (Q 16). We draw attention (Paragraph 117) to the need for a greater research effort on electricity storage. We heard of research in areas ranging from floating marine turbines to solar thermal arrays in deserts. A substantial annual prize for research for the best technological contribution to renewable energy development, as recommended in paragraph 93, would symbolise the importance of applied research in the field. **We call on the Government to look afresh at the UK's research effort into renewables and to consider what more might be done, in a global context, to promote more, and more focussed, research across a range of technologies leading to new, effective and economical ways to reduce carbon emissions.**

Renewable energy in the Planning system

214. Many generators complain about delays in obtaining planning approval, leading to delays in the deployment of renewable generators. A lower level of capacity than expected means that the payments via the Renewables Obligation are spread across a lower level of generation, increasing the support cost per kWh.

215. Scottish and Southern described the planning system as "not fit for purpose" (p 88). A new onshore wind farm could require around 2–3 years of preparatory work, and the planning process could take up to 5 years, followed by a further 1–2 years of construction. Building new transmission infrastructure could in parallel take 3–4 years preparation, plus 2–4 years to construct, and again up to 5 years in planning. Centrica added that around 8 GW of renewable developments are held up in the planning system—the equivalent of 10% of total existing generation capacity (p 97).

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[61] Prima facie, subsidised employment will be less productive than unsubsidised.

216. National Grid saw planning delays as the most significant obstacle to the timely connection of projects and the development of network capacity. Of contracted wind projects in Scotland, only 17% have planning consents. Across Great Britain, only 23% have consents. National Grid supports reform of the planning regime and in particular the Government's proposals to provide for greater certainty in reaching decisions. Scottish and Southern Energy told us that they did not expect every planning decision to be a yes, but they wanted "quick 'yeses' and quick 'nos'". The Renewable Energy Systems said of the planning system: "It is time-consuming and unpredictable, making it a lottery for developers large and small" (Scottish and Southern Energy p 88, Q 229, National Grid p 129, Renewable Energy Systems p 433).

217. But many individuals and community groups felt their views were being ignored, as outlined in Chapter 3. They argued that the planning process did not take account of the effect of wind farm developments on surrounding properties, the landscape and the effects on quality of life through constant low level noise (Two Moors Campaign p 491, John Muir Trust p 382, Barker p 230, Hadden p 325).

218. The Government meanwhile aims to streamline planning processes for major infrastructure projects including energy, establishing a new Infrastructure Planning Commission (IPC). Its remit would cover only onshore wind farms generating more than 50 MW, in England and Wales, so that, in the view of Renewable Energy Systems (p 434) "only 300MW out of the 8000MW of capacity currently in the planning system is affected and not until after 2010".

219. Law firm Lawrence Graham argued that too many obstacles were being put in the way of smaller offshore renewable energy projects, which will be not be handled by the IPC but, amongst others, the proposed Marine Management Organisation "The MMO will have wide-ranging responsibilities, not just in relation to licensing but also nature conservation, spatial planning and enforcement, and concerns have already been expressed as to whether it will also have the resources necessary to handle applications for the more complex developments in any sector. Any perception that as a result the operators of smaller offshore projects may be subject to a less favourable consenting process is likely to make it harder for them to raise capital and may well discourage innovation and more experimental developments offshore" (Lawrence Graham p 397).

220. **We recognise that power companies need a streamlined planning system to approve or reject projects more quickly.** Otherwise the Government's targets for renewable (or, indeed, conventional) energy will be more difficult to meet. **But local and national concerns about environmental degradation must also be addressed and we have received much evidence that this may not be the case at present. It is important to ensure that the planning system adequately assesses the costs to local communities and the balance between national priorities and local decision-making. The Government should also examine how far local communities share in the economic benefits created by wind farm deployment and other renewable projects.**

The 15% target

221. The former Minister of State told us the Government was committed to achieving the 15% target and the resultant ten-fold increase in renewable energy use. It would however be hugely challenging, a view shared by most other witnesses. The Government favoured some trading within the EU if it would bring down the cost to consumers. In particular, the former Minister told us that the last percentage point of renewable energy, needed to raise its share in the UK from 14% to 15% "would probably be the most expensive point to achieve." But in the former Minister's view the target could still be achieved without trading (Q 492). Much may depend on the outcome of negotiations in the EU; there was substantial disagreement over individual national targets at the October European Council.

222. Professor MacKerron thought it was possible but unlikely the target would be achieved, If it were met, it would be at high cost as we would have to build renewable generators at less and less favourable locations (Q 265). Dr David Clarke of the ETI cited the Renewables Advisory Board which believes it is nearly achievable (Q 333).

223. BP saw a risk that because the time scale for the targets was short, investment would be skewed to technologies that worked today as opposed to those which might be right for the longer term (Q 360) Malcolm Keay suggested the pressure to meet the EU target led to too much emphasis now on increasing the quantity of renewable projects at the expense of all other factors and interests involved. He said: "the problem with renewables now is that it is based very much on just getting a certain quantity of renewables built rather than thinking about the ultimate objectives which include reducing carbon emissions but also include preserving local landscapes, amenities and many other things" (Q 101). He thought that "an approach more focused on actual technology development rather than just building arbitrary quantities of renewables might be more effective" (Q 104).

224. A number of witnesses thought the target was impossible to achieve. Mr Keay pointed out that "every single renewables target ever in the UK has been missed and by quite a long way" (Q 82). Professor Helm's view is that "we should have a credible [renewables target] that there is a reasonable prospect that we can achieve" (Q 184). He believed that the government had a policy of providing leadership, and had set a policy of reducing carbon dioxide emissions by 20% between 1990 and 2010. The intention was to demonstrate that, through renewable energy and energy efficiency, this could be done at an extremely low cost, so that other countries would be willing to sign up to Kyoto. In practice, he believed that we had demonstrated that we were unable to achieve the objective, that what we have achieved has been at extremely high cost, and this has not been persuasive. Professor Helm agreed that "we should show leadership and … adopt a tight set of carbon targets, but what I think is most important is that we do not go around wishfully promising that we are going to achieve this renewables target or that particular CO_2 target in a way that is just not credible" (Q 183).

225. **We endorse the Government's objective of ensuring a secure, reliable and affordable supply of energy.**

226. **The Government is right in stating that a portfolio of policies is needed to achieve this objective, if we are also to bring about reduced carbon emissions.** Renewable energy has a part to play, as does nuclear

power, the only other currently existing source of low-carbon energy. Investment in conventional power (preferably equipped with CCS, if and when it becomes available) will also be needed, together with improvements in energy efficiency. **Against a background of developing technologies and uncertain costs, the Government will need to give a firm lead, with clear priorities and realistic objectives, while maintaining the stable framework needed by investors in the context of the long lead times needed by many energy projects.**

227. The main plank of Government policy on renewables is the proposed target of a 15% share of total energy by 2020, most of which is expected to be met by increasing to 30–40% the share of renewables in electricity generation, with most of that coming from wind power, onshore and later offshore. Witnesses' views of the target ranged from challenging to unattainable. The Government is however committed to achieving it and estimates that £100bn of private investment will be needed by 2020. Most, if not all of the cost is to be passed on to the consumer.

228. **We recognise that the Government has committed the UK to contribute to the EU target of 20% renewable energy by 2020 and that a target of 15% for this country is envisaged. But the bulk of the evidence presented to us casts doubt whether, under current policies and with current resources, it will be feasible to increase the share of renewable energy so much in the UK over the time available. This is especially so, as most of the growth is expected to occur in power generation, which represents only a fifth of the UK's energy use, and that this growth will be largely in addition to the substantial replacement programme of old conventional and nuclear plant that has to take place over the same time period.** The UK has a track record of missing its targets in this area and, although meeting this one would mark a step change in the use of renewable energy, failure to meet it would negate the effect of setting and achieving realistic targets and reduce the UK's credibility still further.

229. **We are also concerned that determination to meet the target may lead to an over-emphasis on promoting short-term options, simply because they are available, rather than because they offer the most effective and economical means of reducing carbon dioxide emissions over the longer term.** For example, as we have mentioned earlier in this Report (Chapter 5) the Government should lay at least as much emphasis on the opportunities for renewable heat as on power generation.

230. **We have a particular concern over the prospective role of wind generated and other intermittent sources of electricity in the UK, in the absence of a break-through in electricity storage technology or the integration of the UK grid with that of continental Europe. Wind generation offers the most readily available short-term enhancement in renewable electricity and its base cost is relatively cheap. Yet the evidence presented to us implies that the *full* costs of wind generation (allowing for intermittency, back-up conventional plant and grid connection), although declining over time, remain significantly higher than those of conventional or nuclear generation (even before allowing for support costs and the environmental impacts of wind farms). Furthermore, the evidence suggests that the capacity credit of wind power (its probable power output at the time of need) is very**

low; so it cannot be relied upon to meet peak demand. Thus wind generation needs to be viewed largely as additional capacity to that which will need to be provided, in any event, by more reliable means.

231. **We consider that the Government, if it pursues a renewable energy target in addition to its targets for reducing carbon dioxide emissions across the board, should prioritise the development and promotion of the other effective and economic options, both to bring down carbon dioxide emissions and to achieve security of electricity supply. In that regard it will be important to ensure that incentives to promote those renewables which offer only intermittent supply do not divert attention from, and deter investment in, other low-carbon generation options and thereby risk power shortages. So far as reliability is concerned, the best options among renewable sources of generation are tidal barrage and biomass, which are problematic for other reasons, and hydro-power, which is not, but is already near the limit of its potential in the UK. The most reliable low-carbon alternative to renewables is nuclear power (together with conventional fossil fuel generation with carbon capture and storage, if and when that becomes available).**

CHAPTER 7: RECOMMENDATIONS AND CONCLUSIONS

232. We cannot consider renewable energy in isolation from the rest of the UK energy system and we support measures to include nuclear plants as an essential element of the UK's energy mix (paragraph 74).

233. The cost of electricity from onshore wind farms at good locations would only be comparable with that from fossil fuel generators when the prices of oil, gas and coal are very high or allowance is made for the price imposed for carbon emissions permits (effectively a tax). It is more expensive than nuclear generated power—base cost 7 pence per kWh, as opposed to around 4 pence per kWh for the other technologies. Offshore wind, biomass, wave and tidal power are even more expensive. And these estimates exclude the additional costs of integrating more renewable generation into Britain's electricity grid (paragraph 74).

234. Future developments depend upon many variable factors But it seems clear that the base costs of generation of electricity from onshore wind are likely to remain considerably higher than those of fossil or nuclear generation and that costs of generation of marine or solar renewable electricity are higher still (paragraph 85). We hope that the Energy Technologies Institute's work will yield technological advance and lower costs. The Government should consider, perhaps in collaboration with others, offering a substantial annual prize for the best technological contribution to renewable energy development (paragraph 93).

235. Although their declared purpose is to improve the environment, it is clear that renewable energy installations can also have adverse environmental impacts which the Government should bear in mind as it weighs the benefits and costs of expansion of renewable generation (paragraph 96).

236. Fluctuations in wind speed lead to short term changes in electricity output from wind farms. Greater use of wind power and other intermittent renewable sources therefore requires more backup generation capacity to respond very quickly to, for example, reductions in the output of wind turbines when the wind drops. But the technical challenges and costs of backup generation on a scale large enough to balance an electricity system with a high proportion of intermittent renewable generation are still uncertain. Whereas the highest share of intermittent renewable electricity now being generated in Europe is 15% in Denmark, the UK is expected to reach a share of some 30%–40%. We recommend that the Government should ensure that further work is carried out to clarify the costs and encourage development of technical solutions to deal with intermittency (paragraph 104).

237. The need to part-load conventional plant to balance the fluctuations in wind output does not have a significant impact on the net carbon savings from wind generation (paragraph 105).

238. If some 30 GW of additional (Ev Q 487) renewable capacity were required to meet the EU's 2020 target for the UK a further 14–19 GW of new fossil fuel and nuclear capacity will still be needed to replace plants due to close and meet new demand. The total new installed electricity generating capacity required by 2020 would thus be roughly double the level needed if renewable generation were not expanded (paragraph 111). Investment in renewable generation capacity will therefore largely be in addition to, rather than a

replacement for, the massive investment in fossil-fuel and nuclear plant required to replace the many power stations scheduled for closure by 2020. The scale and urgency of the investment required is formidable, as is the cost (paragraph 112).

239. A breakthrough in cost-effective electricity storage technology would help solve the problem of intermittency and remove a major stumbling block to wider use of renewable energy in the longer term. However, no evidence we received persuaded us that advances in storage technology would become available in time materially to affect the UK's generating requirements up to 2020. We recommend that the Government should as a matter of urgency encourage more research, development and demonstration in energy storage technologies (paragraph 117).

240. Our calculations suggest that the total extra annual cost of increasing the share of renewables in electricity generation from 6% to 34% in 2020 would be £6.8 billion or an extra 38%—the equivalent of an extra £80 a year for the average household. Emissions of carbon dioxide would be reduced by 52 million tonnes a year—in 2007, the UK's emissions were 544 million tonnes. This implies that the additional cost is about £130 per tonne of carbon dioxide emissions avoided (paragraph 128).

241. Ofgem is required to use competition wherever appropriate. We are concerned that the use of competitive tenders implies a piecemeal approach to building the networks of wires and cables required to connect offshore wind farms to the electricity grid, and that as a result the programme could become overly complex and costly. We recommend that Ofgem implements the new system in a way that allows a coordinated approach for organising grid connections to offshore wind farms (paragraph 131).

242. We welcome measures to organise better the queue of renewable generation projects awaiting connection to the electricity grid. They should reduce delays in connecting viable generation projects and push back schemes unlikely to get off the ground (paragraph 134).

243. We consider that the current system of Transmission Use of System charges sends broadly appropriate signals of the costs of locating generators at different points on the system (paragraph 139).

244. Greater interconnector capacity with the Continent would reduce, but not solve, the problems of intermittent renewable generation (paragraph 141).

245. Harnessing renewable sources of heat is often cheaper than for electricity generation and offers a larger target area, as heat accounts for double the final energy demand of electricity. There is no intermittency problem with renewable heat. We recommend that the Government should lay at least as much emphasis on encouraging the development and use of renewable heat as on renewable electricity generation (paragraph 163).

246. We share the concerns raised in the Gallagher Review about existing biofuels. Steps should be taken towards developing second generation bio-fuels as soon as possible. Until the costs of carbon emissions reduction through biofuels come down we recommend that the Government should not seek to increase further the use of biofuels (paragraph 173).

247. It is clear that, although the cost of the technology for carbon capture and storage (if and when it becomes a practical possibility) is inevitably highly

speculative, it will always be more expensive than large-scale carbon-based energy without CCS (paragraph 177).

248. It seems clear there would be little investment in renewable energy without substantial Government support and that a 15% target would not be met without it (paragraph 183).

249. We note the evidence that the cost per kWh of renewable electricity supported by the Renewables Obligation has been significantly higher than the amounts paid via feed-in tariffs abroad, and that much of the excess has been due to other differences in the environment for renewable generation, particularly in the planning system. However, given investors' need for a predictable framework, it seems right to retain the Renewables Obligation, if it is desired to continue increasing generation of electricity from renewable sources (paragraph 189).

250. We are not persuaded that the wish of concerned citizens to make their own contribution to emissions reduction is an adequate justification for a public subsidy for micro-generation (paragraph 198).

251. The returns from micro-generated electricity look too small and uneconomic for the Government to support. But the gains from households using micro-generated heat look much more promising. Government policy should focus instead on households generating renewable heat and on schemes that use renewable heat on a larger scale, such as those covering a housing development, or group of public buildings (paragraph 204).

252. On the evidence submitted to us, renewable electricity is clearly more expensive than fossil fuel-fired and nuclear generation and leads to higher energy bills for consumers and businesses. We estimate that a household which consumes the average amount of electricity will have to pay in 2020 about £80 extra a year. The Government will need to take higher costs on board in framing its policies towards fuel poverty, noting the high correlation between fuel poverty and poorly-insulated homes (paragraph 208).

253. We call on the Government to look afresh at the UK's research effort into renewables and to consider what more might be done, in a global context, to promote more, and more focussed, research across a range of technologies leading to new, effective and economical ways to reduce carbon emissions (paragraph 213).

254. We recognise that power companies need a streamlined planning system to approve or reject projects more quickly. But local and national concerns about environmental degradation must also be addressed. It is important to ensure that the planning system adequately assesses the costs to local communities and the balance between national priorities and local decision-making. The Government should also examine how far local communities share in the economic benefits created by wind farm deployment and other renewable projects (paragraph 220).

255. We endorse the Government's objective of ensuring a secure, reliable and affordable supply of energy (paragraph 225).

256. The Government is right in stating that a portfolio of policies is needed to achieve this objective, if we are also to bring about reduced carbon emissions. Against a background of developing technologies and uncertain costs, the Government will need to give a firm lead, with clear priorities and realistic objectives, while maintaining the stable framework needed by investors in the

context of the long lead times needed by many energy projects (paragraph 226).

257. We recognise that the Government has committed the UK to contribute to the EU target of 20% renewable energy by 2020 and that a target of 15% for this country is envisaged. But the bulk of the evidence presented to us casts doubt whether, under current policies and with current resources, it will be feasible to increase the share of renewable energy so much in the UK over the time available. This is especially so, as most of the growth is expected to occur in power generation, which represents only a fifth of the UK's energy use, and that this growth will be largely in addition to the substantial replacement programme of old conventional and nuclear plant that has to take place over the same time period (paragraph 228).

258. We are also concerned that determination to meet the target may lead to an over-emphasis on promoting short-term options, simply because they are available, rather than because they offer the most effective and economical means of reducing carbon dioxide emissions over the longer term (paragraph 229).

259. We have a particular concern over the prospective role of wind generated and other intermittent sources of electricity in the UK, in the absence of a break-through in electricity storage technology or the integration of the UK grid with that of continental Europe. Wind generation offers the most readily available short-term enhancement in renewable electricity and its base cost is relatively cheap. Yet the evidence presented to us implies that the **full** costs of wind generation (allowing for intermittency, back-up conventional plant and grid connection), although declining over time, remain significantly higher than those of conventional or nuclear generation (even before allowing for support costs and the environmental impacts of wind farms). Furthermore, the evidence suggests that the capacity credit of wind power (its probable power output at the time of need) is very low; so it cannot be relied upon to meet peak demand. Thus wind generation needs to be viewed largely as additional capacity to that which will need to be provided, in any event, by more reliable means (paragraph 230).

260. We consider that the Government, if it pursues a renewable energy target in addition to its targets for reducing carbon dioxide emissions across the board, should prioritise the development and promotion of the other effective and economic options, both to bring down carbon dioxide emissions and to achieve security of electricity supply. It will be important to ensure that incentives to promote those renewables which offer only intermittent supply do not divert attention from, and deter investment in, other low-carbon generation options and thereby risk power shortages. So far as reliability is concerned, the best options amongst renewable sources of generation are tidal barrage and biomass, which are problematic for other reasons, and hydro power, which is not, but is already near the limit of its potential in the UK. The most reliable low-carbon alternative to renewables is nuclear power (together with conventional fossil fuel generation with carbon capture and storage, if and when that becomes available) (paragraph 231).

APPENDIX 1: ECONOMIC AFFAIRS COMMITTEE

The members of the Select Committee which conducted this inquiry were:

Lord Best
Lord Griffiths of Fforestfach
Baroness Hamwee
Lord Kingsdown
Lord Lamont of Lerwick
Lord Lawson of Blaby
Lord Layard
Lord Macdonald of Tradeston
Lord MacGregor of Pulham Market
Lord Moonie
Lord Paul
Lord Turner of Ecchinswell*
Lord Vallance of Tummel

* Lord Turner has not taken part in the work of the Committee since July 2008.

Professor Richard Green, Director, Institute for Energy Research and Policy, University of Birmingham, was the Committee's Specialist Adviser.

Declaration of Interests

Full lists of Members' interests are recorded in the Lords Register of Interests. Details can be found at the following web address:

http://www.publications.parliament.uk/pa/ld/ldreg.htm

APPENDIX 2: LIST OF WITNESSES

The following witnesses gave evidence. Those marked * gave oral evidence.

* BP
* Professor AbuBakr Bahaj, Southampton University

Mr Andrew Bain

Ms Carolyn Barker

Mr Derek Birkett

Bishopton Village Hall Management Committee

Mr Philip Bratby

* Professor Tony Bridgwater, Aston University

British Energy

British Hydropower Association

* British Wind Energy Association

Campaign for Responsible Energy and Development in Tynedale

Campaign to Protect Rural England, Devon

Campaign to Protect Rural England, Durham

Carbon Capture and Storage Association (CCSA)

Maureen and Peter Caswell

* Centrica

Christofferson Robb and Company

* Climate Change Capital

Jane and Julian Davis

* Department for Business Enterprise and Regulatory Reform: Malcolm Wicks, a Member of the House of Commons, Minister of State for Energy, Mr Simon Virley, Head of the Renewable Energy and Innovation Unit, and Ms Tera Allas, Chief Economist Energy Group
* E.ON UK

EDF Energy

EEF

* Professor Paul Ekins, King's College London

Energy Networks Association

* Energy Technologies Institute

Energy Technology for Sustainable Development Group

Energywatch

Environmental Defense Fund

Environmental Industries Commission

Environmental Research Institute

Dr John Etherington

* Falck Renewables Limited

Mrs Barbara J Frey

* Friends of the Earth

Genersys plc

Mr Colin Gibson

Christiane Golling and Marco Nicolosi, Institute of Energy Economics, Cologne

* Greenpeace

Grünhaus Project, Liverpool

Mr Peter Hadden

J.H.R. Hampson

* Professor Dieter Helm, Oxford University

Highlands Against Wind Farms

Highlands Before Pylons

Rear Admiral Robin Hogg and Professor Leslie Bradbury

Mr Robert Horler

House of Bishops' Europe Panel, Church of England

W.J. Hyde

Institute of Physics

Institution of Engineering and Technology (IET)

Institution of Mechanical Engineers

International Energy Agency

Mrs Delia Jack

Professor Michael Jefferson

Professor Nick Jelley

John Muir Trust

* Mr Malcolm Keay, Senior Research Fellow, Oxford Institute for Energy Studies

Mr Neil Kermode

Professor Michael Laughton

Lawrence Graham LLP

Dr and Mrs J Lyne

Dr Rayner Mayer and Dr Roger Bentley

Sir Donald Miller

Mynydd Llansadrwn Action Group

* National Grid

Natural England

Mr Michael Negus
* Dr Karsten Neuhoff, University of Cambridge
* Professor David Newbery, Cambridge University
* Ofgem
Mrs N Penk, Mr C Penk and Mr DPC Penk, Pitfield Farm
Richard Phillips
Renewable Energy Association
* Renewable Energy Foundation
Renewable Energy Finance-Policy Project, Chatham House
RES UK & Ireland Ltd
Research Councils UK (RCUK)
Royal Academy of Engineering
Royal Society of Edinburgh
Scientists for Global Responsibility
* Scottish and Southern Energy plc
Scottish Power Ltd
Scottish Sustainable Energy Foundation
Mr Alan L. Shaw
* Shell UK
Professor Peter Smith
Mr Paul Spare
* Dr Neil Strachan, King's College London
Town and Country Planning Association
Two Moors Campaign
* Dr Simon Watson, Loughborough University
Wavegen
Revd John Wylum

APPENDIX 3: CALL FOR EVIDENCE

The Economic Affairs Committee has decided to conduct an inquiry into 'The Economics of Renewable Energy'.

Evidence is invited by 16 June 2008. The Committee will welcome written submissions on any or all of the issues set out below.

Amid concerns over climate change the Government aims to increase the use of renewable energy sources, such as wind, tidal, biomass, biofuels and solar power, alongside other measures to reduce greenhouse gas emissions such as promoting greater energy efficiency.

Under EU targets, 15% of energy consumed in the UK should come from renewable sources by 2020. Yet Government figures show only 1.8% of Britain's energy came from renewables in 2006. Electricity generation, as opposed to heating and transport, is widely thought to have the most potential for greater use of renewable sources. But while the share of renewables in electricity generation has been growing, it was still only 4.5% in 2006.

This inquiry aims to set out the costs and benefits of renewable energy and establish how they compare with other sources of energy. It will also examine the Government's policy towards renewable energy.

Among the issues being examined in the inquiry are:

(1) How do and should renewables fit into Britain's overall energy policy? How does the UK's policy compare with the United States, Australia, Canada, and other EU countries?

(2) What are the barriers to greater deployment of renewable energy? Are there technical limits to the amount of renewable energy that the UK can absorb?

(3) Are there likely to be technological advances that would make renewable energy cheaper and viable without Government support in the future? Should, and how could, policy be designed to promote such technological advances?

(4) Has Government support been effective in leading to more renewable energy? What have been the most cost-effective forms of support in the UK and other countries and what should the balance be between subsidies, guaranteed prices, quotas, carbon taxes and other forms of support? Should such support favour any particular form of renewable energy over the others? For instance, what are the relative merits of feed-in tariffs versus the UK's present Renewables Obligation Certificate (ROC) regime?

(5) On top of the costs of building and running the different types of electricity generators, how much investment in Britain's transmission and distribution networks will different renewable energy sources require compared to other forms of generation? Are the current transmission and distribution systems capable of managing a large share of intermittent renewable electricity generation and, if not, how should they be changed? Are the rules about how we connect capacity to the grid supportive of renewables?

(6) How do the external costs of renewable generation of electricity—such as concerns in many affected rural areas that wind farms and extra pylons

spoil areas of natural beauty—compare with those of fossil fuels and nuclear power? How should these be measured and compared? Is the planning system striking the right balance between all the different considerations?

(7) How do the costs of generating electricity from renewables compare to fossil fuel and nuclear generation? What are the current estimates for the costs of "greener" fossil fuel generation with carbon capture and storage and how do these costs compare to renewable generation? What impact do these various forms of electricity generation have on carbon emissions?

(8) How do the costs and benefits of renewable electricity generation compare to renewables in the other key forms of energy consumption—transport and heating?

(9) If the UK is to meet the EU target that by 2020 15% of energy consumed will come from renewables, will most of this come from greater use of renewable sources in electricity generation? If so, why? Should British support for renewables in other countries be allowed to contribute towards meeting the target for the UK?

(10) How would changes in the cost of carbon—under the European emissions trading scheme—affect the relative costs of renewables and other sources of energy? Would a more effective carbon emissions trading scheme remove the need for special support of renewable energy?

(11) What are the costs and benefits of the present generation of biofuels? Will there be a second generation of biofuels and, if so, what are the estimated costs? What are, or are likely to be, the carbon emission impacts of first and second generation biofuels, and what are the other relevant environmental effects?

APPENDIX 4: CURRENT STATUS, FUTURE PROSPECTS AND ACTIONS ON RENEWABLE TECHNOLOGIES IN THE UK

Where are we?	What can be achieved?	What is holding it back?	What needs to be done?
ON-SHORE WIND POWER Technology is mature and economical with current policies in utility scale application. Not really effective in small scale application. Very large projects will have significant visual impact in UK landscape	Gradual expansion of capacity (over 15GW of potential wind capacity has been applied for in Scotland alone).	Objections under planning regime. Transmission grid capacity. Increasing costs due to global competition for raw materials and equipment. Concerns about managing variability for increased wind capacity.	R, D&D into active grid management.
OFF-SHORE WIND POWER Fundamental technology is mature but uneconomic under current policies. Deployment offshore will continue to bring technological and operational challenges.	Potential for large scale development.	High capital cost—increasing due to global competition for raw materials and equipment. Transmission grid capacity. Transmission/ distribution grid expansion. Concerns about managing variability for increased wind capacity.	May be favoured under reformed (banded) Renewables Obligation. R, D&D into active grid management.
HYDROELECTRIC POWER Mature technology.	Around 1000 MW of future potential in UK, vast remaining potential worldwide		
TIDAL POWER Several technologies exist in prototype, in need of full-scale demonstration and commercialisation. About 10–15 years from full commercialisation, and uncertainties over cost competitiveness.	Sizeable natural resource to be exploited in UK. Potential for technology export.	Risk/cost of demonstration. High initial costs and extended operating lifetimes.	Demonstration support. Development of standards.

Where are we?	What can be achieved?	What is holding it back?	What needs to be done?
WAVE POWER Several technologies exist in prototype—all inevitably large with high embedded energy and uncertain maintenance and operating costs. At least 15 years from large scale commercialisation.	Sizeable natural resource to be exploited in UK. Potential for technology export.	Risk/Cost of demonstration. No large companies pushing the technology. Size of devices (typically 100m per MW) and impact on shipping. Requires hundreds of machines, each the size of a tube train, packed with hydraulics, generators, etc Energy transmission from large numbers of floating structures. Limited supply chain.	Demonstration support. Development of standards. Deployment requires the commitment of large shipbuilders and power engineering companies—commitment that will take time to build.
TIDAL BARRAGE Technology is proven, but capital costs tend to be very high.	Multi GW scale possibilities in UK (e.g. Severn Barrage), but power limited to certain (changing) times of day.	Cost, environmental issues, investment risk, grid connections.	Studies in progress. Substantial structural change to electricity market and/or government subsidies probably needed for large schemes.
SOLAR PHOTOVOLTAICS Mature but costly technology, currently used mainly in niche and 'showcase' applications.	Limited potential for improvement of current (first and second generation) technology but some scope to improve production costs through improved manufacturing processes. Higher efficiency and more flexible materials currently in development could result in lower-cost, higher-efficiency applications. Mass deployment has been achieved where government support has been substantial (e.g. Germany, Japan).	High capital cost. Competition for raw materials (silicon) resulting in high cost. Lack of skilled installers. Lack of information and accreditation schemes.	R&D into manufacturing. R&D into "second generation" thin film silicon PV, organic PV and high-efficiency "third generation" PV (e.g. quantum dots). Skills development. Technology and installation accreditation.

Where are we?	What can be achieved?	What is holding it back?	What needs to be done?
SOLAR THERMAL ENERGY Technology is mature and relatively cost-effective.	Large potential for domestic use, both retrofit and new build.	Lack of skilled installers. Lack of information and accreditation schemes. Integration with building stock.	Skills development. Technology and installation accreditation. Introduction of 'microgeneration-ready' standards for new homes.
CONCENTRATED SOLAR ELECTRICITY Mature but quite expensive.	Very suitable for desert regions—requires plenty of sunshine and large land areas.	Not suitable for UK; long term potential for mass application in North Africa and export to Europe.	Support studies.
ENERGY FROM WASTE A variety of mature or near-market technologies exist for recovering energy from waste. Electricity generation from landfill gas is the most widely used.	Significant potential, depending on local circumstances.	Potential for landfill gas limited by restrictions on landfill. Planning consent for thermal waste to energy plants.	Interaction with waste management policies.
BIOMASS Technologies using 'first generation' biomass resources for heat, power generation and transport are fairly mature but relatively costly. Higher-yield 'second generation' biofuels are being researched but are at least 10–15 years from commercialisation.	Biomass for heat and power generation could be more widely used in parts of the country. Potential limited by other demands for land use, especially food crops. Currently biomass is imported from Europe, this is likely to reduce as EU states all turn to biomass to achieve their renewable energy targets.	Lack of supply chain coordination. Lack of skilled installers. Lack of information and accreditation schemes.	Establishment of sustainable supply chains. Skills development. Resource, technology and installation accreditation. R&D into 'second generation' biofuels.

Where are we?	What can be achieved?	What is holding it back?	What needs to be done?
GEOTHERMAL Mature but costly technology for UK. Applied on a large scale at lower costs in countries with good resource (e.g. Iceland, Philippines).		High cost of installation. Lack of skilled installers. Lack of information and accreditation schemes. Integration with building stock.	Skills development. Technology and installation accreditation. Introduction of 'microgeneration-ready' standards for new homes.
GROUND SOURCE HEAT PUMPS Mature technology that can be cost effective.	Significant opportunities in space heating, easiest to apply in new buildings or major refurbishments.	Getting people to apply the technology.	Changes to building regulations
GREEN BUILDING DESIGN (USING NATURAL HEAT, LIGHT AND COOLING) Exemplar projects abound but not deployed universally.	Huge opportunities for new construction and retrofit, more examples of best practice needed for retrofit.	Lack of interest/ knowledge amongst people commissioning buildings or retrofits; weak building regulations and enforcement.	Aggressive approach to building regulations and their enforcement; better marketing of the benefits, higher energy prices.
HYDROGEN AND FUEL CELLS Hydrogen is not inherently renewable; in the near term, the most likely sources are fossil fuels, resulting in CO_2 emissions unless accompanied by abatement technology. This is an immature technology.	Trials in USA using fuel cells power by off peak electricity to provide hydrogen for motorcycles. Portable power sources (e.g. phones, laptops) in advanced development.	Finding cost effective applications and developing hydrogen production infrastructure. Also ensuring that power to make the hydrogen does not come from high carbon sources.	Basic R&D on hydrogen generation. R&D on hydrogen transport infrastructure requirements.

Where are we?	What can be achieved?	What is holding it back?	What needs to be done?
STORAGE TECHNOLOGIES			
PUMPED STORAGE HYDRO Mature technology, often quite expensive	Allows storage of energy to balance intermittent renewables and/or demand peaks and troughs. Large scale possibilities exist in UK and have been studied in the past.	Not an attractive investment, also potential environmental issues.	Flagging of opportunities, and impact on market price of intermittency. Will not be commercially attractive until value of intermittency or gap between peak and base prices becomes high.
DEMAND CONTROL Technically possible but massive deployment challenge	Potentially allows non essential demand to be removed at times of peak demand or low outputs from intermittent generation.	Market not yet ready to deploy it; attention needed to regulatory and legislative frameworks.	Deployment of smart meters is a first step and government is active through Energy Bill enabling provisions, changes to domestic appliance standards and wiring regulations may be needed. Deployment of ESCOs would help (as in Energy White Paper)
SMART WHITE GOODS Manufacturers are engaged with innovators; selective trials taking place.	Potentially allows interruptible demand to be 'intelligently disconnected' at times of power system stress. The value of this is could be significant because it may be a cost effective way of replacing expensive fast-response standby generation on the grid.	Constructing the 'value chain' so that those who bear the costs can receive the rewards. Also needs mass roll out. Needs consumer acceptance.	Proving the technology (in hand with some big white goods manufacturers); demonstrating it effectiveness and commercial value; constructing a route to market and the value chain for rewards.
ELECTROCHEMICAL STORAGE Significant R,D and D done in UK a few years ago but subsequently abandoned.	Short term energy storage to manage demand peaks or low intermittent generation	Market not yet interested.	More development work. Will not be commercially attractive until value of intermittency or gap between peak and base prices becomes high.

Source—The Institution of Engineering and Technology

APPENDIX 5: COMPARATIVE COST ESTIMATES SUBMITTED TO THE INQUIRY IN MID-2008 OF RENEWABLE (EXCLUDING HYDRO), FOSSIL AND NUCLEAR ENERGY GENERATION. IN THE CASE OF RENEWABLES, THEY DO NOT ALLOW FOR EXTRA COSTS OF BACKUP CONVENTIONAL GENERATING CAPACITY OR GRID INTEGRATION, WHICH ARE EXPLORED IN CHAPTER 4.

	Laughton and REF[a] using figures from PB Power	REF[a] using IPA figures	British Energy using IPA for REF[a] (with varying carbon price)	British Energy using BERR Energy Review 2006	Centrica	E.On	British Wind Energy Association
Offshore wind	10	6.4–6.9	6.6	5.6–8.9	7.4–11	10.7	
Onshore wind	5.6	4.1–4.8	4.4	5.1–6.4		7.5	6.2
Biomass	7						
Tidal	12.6						
Wave	21.8						
Combined Cycle Gas Turbine (CCGT) [c]	4.2	4.8–5.1	4.7–5.7	4.5–5.2	5.6–9.2	4.4–5.9	5.5–6.3
Open Cycle Gas Turbines [c]	7						
Coal Plant with no carbon abatement technologies	4.2	4.4–4.9	4.2–6.4	2.6–4	5.5–8.0	4.2–7.1	5.0–6.8
Coal with carbon capture and storage [b]		4.9–5.4	5.1–5.3			6.8–7.1	
Cleaner coal—Integrated Gasification Combined Cycle (IGCC)	6.4	4.9–5.1	4.5–6.6	2.9–4.3	6.0–8.9		
IGCC with carbon capture [b]				4.5–5.2	5.7–8.5		
Nuclear	3.8	3.6–3.9	3.7	3–4.4	5.0–7.0	3.9	6.0

a REF stands for Renewable Energy Foundation.

b No power plant currently operates with carbon capture and storage.

c Both Closed Cycle and Open Cycle Gas Turbines use gas mixed with air to fuel a turbine. But the CCGT also uses the heat from the turbine exhaust to also create steam which turns a second turbine. The CCGT is therefore more efficient and hence cheaper.

APPENDIX 6: FUTURE RENEWABLE ENERGY TECHNOLOGIES

New forms of renewable energy and improvements to existing technologies such as wind would help cut carbon emissions. A long term prospect sometimes discussed is the possibility of importing electricity generated from panels of solar photovoltaic cells placed in the Sahara desert. Another possible development in the Sahara is solar thermal power. Steel and glass mirrors would capture energy from the sun to boil water with the resulting steam used turning turbines to generate electricity. Algeria is reported to be building an experimental solar thermal power plant 400 miles south of Algiers which could open next year.[62] One of the key difficulties with both ideas would be transmitting the electricity over the huge distance from the Sahara to consumers in Britain. The Institution of Engineering and Technology argued such projects had long term potential for North Africa with energy being exported to continental Europe but were not suitable for the UK. Another possibility might be to use solar generated electricity to obtain hydrogen which could then be shipped to the UK (and other countries) as a transport fuel.

Researchers are also examining ways to improve wind power, a relatively well-established form of renewable generation. Norwegian oil company StatoilHydro is testing technology that would enable offshore turbines to float instead of having to plant them on the seabed. If the tests are successful turbines could then be used in much deeper water where the stronger wind is more consistent. More power could then be generated which could help bring down the cost per unit of electricity of offshore generation which is currently higher than that of the more widely used onshore turbines.

As outlined in Chapter 5 a heat technology that could be developed in the future is the injection of biomethane that can be injected into the gas grid. Biogas—a mixture of methane and carbon dioxide—is first produced by bacteria breaking down organic material such as food waste in the absence of oxygen through a process called anaerobic digestion. The carbon dioxide is then removed from the biogas to leave biomethane. Some European countries have already begun injecting biomethane into their gas grids but the Government's renewable energy consultation document says such technologies require more innovation before they can be deployed in the UK. The Government has contributed £10m towards the construction of new anaerobic digestion plants.

In transport, scientists are developing 'second generation' biofuels. First generation biofuels—which are in commercial production today—are made from the parts of plants that could otherwise be used as food such as wheat grain and sugar cane. But second generation bio-fuels—which are not yet available on a commercial scale—would be made using parts of plants not used for food or whole plants that are not suitable for food. Other possible avenues include electric cars, which are not yet widely available, and hydrogen powered vehicles, which are still in development. While both use electricity they could count as renewable technologies if they use renewable sources of power. Furthermore, as outlined in Chapter 5, such vehicles could store electricity which would help ease the problems of intermittency associated with most forms of renewable power generation.

62 The Economist, The Future of Energy, June 19, 2008

APPENDIX 7: RENEWABLE ELECTRICITY IN DENMARK

Denmark has the highest share of wind-generated electricity in the EU—15.7% of its total consumption in 2006. The country is accordingly held up as an example by some commentators, while others draw attention to features of the company's experience that may not be transferable abroad. Denmark is a relatively small country, with strong transmission links to Germany, Norway and Sweden. The (separate) electricity systems in Eastern and Western Denmark joined the Nordic electricity wholesale market, Nord Pool, in 1999 and 2000 respectively. When the transmission lines are not congested, this market sets a single price for power in Denmark, Finland, Norway and Sweden, ensuring efficient levels of cross-border trade.

The columns in figure below show how the level of generation in Denmark has varied over time. The output of wind generators has increased by a significant amount, whereas the output of coal-fired plants has fluctuated dramatically from year to year. The top line in the figure shows that Danish electricity consumption has grown steadily, and cannot be the cause of the fluctuating output.

The bottom line in the figure shows Denmark's net exports of electricity.[63] There is clearly a strong relationship between net exports and the output of coal-fired generation. The graph does not show this, but those net exports are, in turn, strongly linked to the output of hydro-electric power in Finland, Norway and Sweden. In dry years, with relatively little hydro output, exports from Denmark (and Germany) make up some of the slack.[64] There is little sign of a long-term trend for exports to either increase or decrease over time.

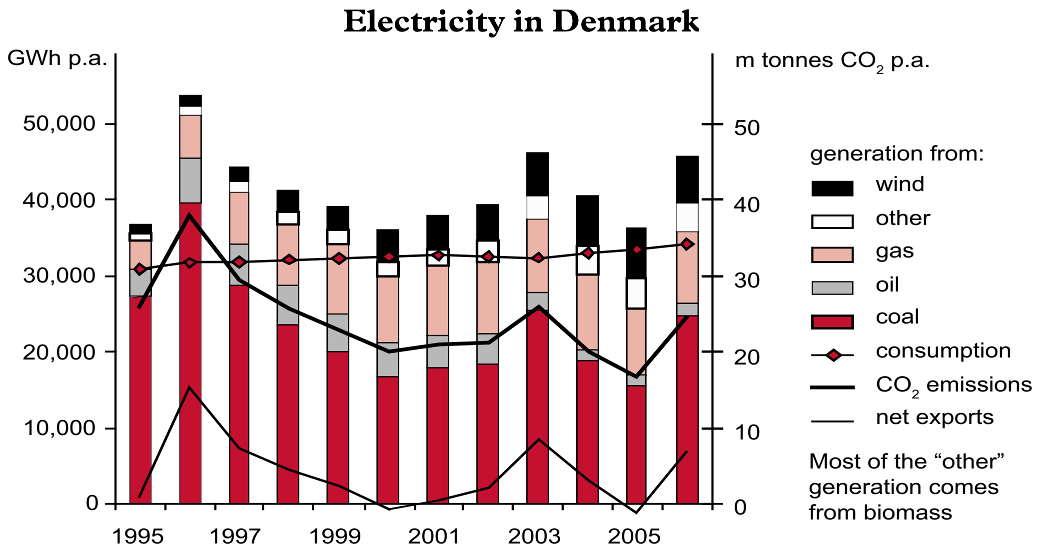
The middle line in the figure shows Denmark's emissions of carbon dioxide from electricity generation. These emissions are clearly linked to the amount of coal- (and oil) fired generation. In other words, Denmark emits more carbon dioxide in years when dry conditions in Scandinavia mean that Danish generators are able to send more power northwards. They do so by increasing the output of coal-fired power stations.

Since Denmark's total output of electricity does not depend solely on conditions within the country, the country's movement towards a lower-carbon energy system is better measured by emissions of carbon dioxide per kWh generated than by total emissions. Carbon dioxide emissions per kWh of electricity generated were 24% lower in 2006 than in 1995.[65]

63 The vertical axis starts at zero, although net exports can be negative, because in the two years in which Denmark was a net importer of electricity, the amounts involved were small (665 GWh in 2000 and 1,369 GWh in 2005).

64 The correlation coefficient between Denmark's net exports and hydro generation in the other three countries is -0.75, showing a strong inverse relationship, while the correlation between Danish net exports and coal-fired generation is even stronger, at 0.89.

65 The 2006 figure did represent a slight increase on 2005, but this was because the increase in net exports led to an increase in the level of coal-fired generation, and the average emissions rose accordingly.



The Danish wind industry does gain significantly from the country's strong interconnections to its neighbours. On an hour-to-hour basis, there is a clear tendency for Denmark to export power when the wind is high, and to import power when it has little wind generation. Without the ability to exchange power with its neighbours, Denmark would find it more difficult to integrate its wind generators—we have not attempted to assess how difficult. However, the exchanges within a year tend to balance themselves out—over a year as a whole, we found no evidence of a correlation between Denmark's net exports and its output from wind generation.

APPENDIX 8: TRANSMISSION ACCESS PROPOSALS

The industry is currently assessing longer-term changes to the organisation of transmission access. National Grid told us that it is developing three proposals (p 129). The first is to move away from a philosophy of "invest then connect" to one of "connect and manage". Rather than waiting for distant reinforcements to the grid to be completed, the transmission companies would connect a new generator as soon as the local system was capable of accepting its output. If constraints elsewhere on the system meant that from time to time the generator's output could not be accepted, the station would have to be "constrained off", and would be compensated for the fact that it could not sell its power.

The second proposal involves the short-term trading of access rights between generators. This would allow a wind farm to connect to the system with access rights to sell only a proportion of its potential output, if that was all that the grid could accept. If the wind is strong and the wind farm could generate more than this proportion, it would find another generator (which would probably have to be in the same area) that was not using all of its access rights, and buy the surplus. Since the conventional stations would not all be needed when the wind was strong, there should in principle be rights available, and this would allow stations to share transmission capacity.

The third proposal is to bring in a series of auctions for long-term capacity rights. Ofgem told us that if generators have to make a clearer financial commitment of their future demand for capacity, this would give National Grid a lot more information about generators' demand for access to the network (p 176).

A number of companies commented on this review. A key concern of EDF Energy is that the Transmission Access Review primarily introduces measures to improve short term allocation efficiency which could in turn increase long term uncertainty for market participants, and undermine long term investment in both generation and transmission. In the company's view, the core issue is the scarcity of transmission capacity, and so securing this capacity and utilising it well must remain the prime objective of the review (p 174).

Renewable Energy Systems UK and Ireland Ltd argued that "giving priority access for connection and production to renewable energy capacity means not doing so for centralised fossil plant. It is essential to overcome resistance from the affected incumbents. Renewables must have priority grid access and dispatch. Shared access rights and flexible security of supply rules need to be introduced" (p 436).

E.ON argued that the reform of transmission access arrangements will need to balance the need to connect new renewable generation and the need to avoid imposing additional costs on the system by constraining off thermal and fossil plant which National Grid then has to compensate (p 108). The Renewable Energy Association argued that renewable generators should be given priority access and dispatch rights, and that this was likely to become law under the forthcoming EU Renewable Energy Directive (Q 161).

At present, if National Grid cannot accept a station's output because of constraints on the transmission system, the generator is required to buy back its output in the Balancing and Settlement Mechanism, the short-term electricity market. A conventional generator would normally be willing to pay any price that is less than the costs it would save by not generating (which would be dominated by fuel costs) in order to buy back its power. A wind station, however, incurs very few variable costs when it generates, and gives up income from the sale of Renewables

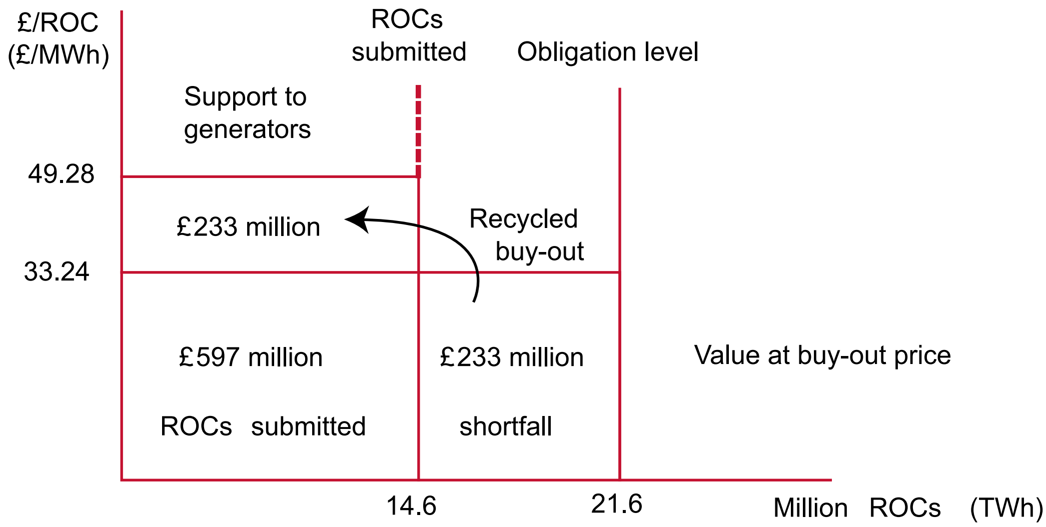
Obligation Certificates. It might therefore ask National Grid to be compensated for giving up this income, effectively offering to buy back its power only at a negative price. In other words, National Grid would be paying the wind farm not to generate. In such circumstances, it would obviously be more economic to find a conventional plant to constrain off instead, but this might not be possible, if none was in the same (constrained) part of the grid, or all the stations there were required for balancing purposes. We are therefore uncertain that priority dispatch rights would have a significant impact in practice, given the current system of constraint payments.

APPENDIX 9: THE RENEWABLES OBLIGATION

A number of mechanisms are used to support renewable energy. Renewables Obligation Certificates (ROCs) are the most direct. The Renewables Obligation requires electricity suppliers to deliver a set proportion of power from renewable sources—9.1% was set for 2008–09.[66] Generators receive one ROC for every 1,000 kWh of electricity generated, and can sell these to suppliers. A supplier unable to surrender ROCs equal to the set percentage must pay £35.76 for each missing certificate into a buy-out fund which is then redistributed amongst the suppliers who surrendered ROCs, in proportion to the number given up. The market price of ROCs rises above the buy-out price if a shortfall is expected, for each ROC allows the holder not only to avoid paying the buy-out price, but also to share in the money paid in by those with a shortfall. The Renewables Obligation covers Great Britain, while the Northern Ireland Renewables Obligation runs on a similar basis but with a lower target (3.0% in 2008/9).

The design of the Renewables Obligation effectively means that the total payment to renewable generators, over and above the market price they receive for their power, should be fixed. In 2006–7, the amount of electricity covered by the Obligation in the UK was 21.6 TWh (6.7% of electricity supplied) and the buy-out price was 3.32 pence per kWh. If no ROCs had been submitted, suppliers would have paid £720 million to the buy-out fund. In fact, they submitted 14.6 million ROCs, and paid £233 million to the fund. This was then redistributed to the suppliers who had submitted ROCs, giving them £16.04 per ROC submitted. With hindsight, the overall value of the ROC to the supplier was thus £49.28 (£16.04 plus £33.24). If market prices had reached this level (in 2007, they were actually slightly below it), the total value to generators would have been £720 million: 21.6 TWh × 3.32 pence per kWh. The same result would hold for any level of renewable generation below the obligation level. The figure below shows this result.

Payments under the Renewables Obligation



Before the Renewables Obligation, renewable (and nuclear) generation was supported through a Non-Fossil Fuel Obligation (in England and Wales) and the

[66] Ofgem, Renewables Obligation—Interim total obligation levels for 2007–08, August 5, 2008, available at: http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/Renewables%20Obligation%20-%20Interim%20Total%20Obligation%20Levels%20for%202007–08.pdf

Scottish Renewables Obligation. The electricity regulator and the Non Fossil Purchasing Agency organised a series of tenders to buy power from renewable generators, mostly for 15 years, and recovered the cost from a percentage levy which suppliers had to add to consumers' bills. Many of the tenders were from generators that had not yet received planning permission, and not all of the contracted generation was delivered. The early contracts have expired, and almost all of these generators are now involved in the Renewables Obligation—the Agency resells the power and ROCs for generators with current contracts.

If renewable electricity is to supply 32 per cent of electricity demand, to take the number in the Government's Renewables Consultation, and all of this is to be supported by the Renewables Obligation, it would have to be set at a much higher level. Although the Government has announced plans for a feed-in tariff for some small scale generation technologies, we will calculate the cost of support for these "as if" it was still given through the Renewables Obligation. Ignoring the effects of banding, which will give more ROCs to technologies such as offshore wind, a Renewables Obligation for 32 per cent of electricity would add 1.14 pence per kWh to the price of electricity—that is, 32 per cent of 3.576 pence per kWh (the 2008–9 buy-out price). This would add £50 to the average domestic consumer's annual electricity bill. On top of this, the system integration costs shown in Table 4 would add a further 0.65 pence per kWh, or another £30 a year.

If we take account of the impact of banding, which gives some technologies more ROCs per MWh generated, and others less, the number of ROCs required to reach 32 per cent renewable generation will change. Since much of the additional renewable generation would come from offshore wind, which will receive more than 1 ROC per MWh (1.5 ROCs per MWh for the next few years), the number of ROCs required is likely to exceed 32 per cent. If it reaches 37 per cent of electricity supplied, the cost of the Renewables Obligation would be £60 per year for the average household.

APPENDIX 10: GLOSSARY OF TERMS AND ABBREVIATIONS

BERR	Department for Business, Enterprise & Regulatory Reform
CCS	Carbon Capture and Storage
CERT	Carbon Emissions Reduction Target
CHP	Combined Heat and Power
CO_2	Carbon dioxide
DTI	Department of Trade and Industry
ECU	European Currency Unit
EDF	Électricité de France
ETI	Energy Technologies Institute
ETS	Emissions Trading Scheme
EU	European Union
EWI	Energiewirtschaftliches Institut (Institute of Energy Economics), University of Cologne
GW	Gigawatt
GWh	Gigawatt Hour
IEA	International Energy Agency
IET	Institution of Engineering and Technology
IPC	Infrastructure Planning Commission
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt hour
MMO	Marine Management Organisation
MW	Megawatt
Ofgem	Office of Gas and Electricity Markets
p/kWh	Pence per kilowatt hour
R&D	Research and Development
R, D&D	Research, Development and Demonstration
RO	Renewables Obligation
ROCs	Renewables Obligation Certificates
SKM	Sinclair Knight Merz
SSE	Scottish and Southern Energy
UKERC	UK Energy Research Centre

Appendix 2 PV Watts Parameters

PV Calculations for Brisbane using PV Watts by US National Renewable Energy Laboratory (NREL)

Station Identification	
City:	Brisbane
Country/Province:	AUS
Latitude:	27.38° S
Longitude:	153.10° E
Elevation:	5 m
Weather Data:	IWEC
PV System Specifications	
DC Rating:	1.50 kW
DC to AC Derate Factor:	0.770
AC Rating:	1.15 kW
Array Type:	Fixed Tilt
Array Tilt:	27.4°
Array Azimuth:	0.0°
Energy Specifications	
Energy Cost:	0.1700 A$/kWh

• Table 6 - 1.5kW Output Brisbane Insolation

Results			
Month	Solar Radiation ($kWh/m^2/day$)	AC Energy (kWh)	Energy Value (A$)
1	6.15	197	33.49
2	5.70	163	27.71
3	5.62	183	31.11
4	5.06	159	27.03
5	4.05	134	22.78
6	4.18	136	23.12
7	4.70	159	27.03
8	5.48	185	31.45
9	6.20	200	34.00
10	5.79	190	32.30
11	6.07	190	32.30
12	6.18	200	34.00
Year	5.43	2097	356.49

The monthly and yearly energy production are modelled using the PV system parameters you selected and weather data that are typical or representative of long-term averages. For reference, or comparison with local information, the solar radiation values modelled for the PV array are included in the performance results.

Because weather patterns vary from year-to-year, the values in the tables are better indicators of long-term performance than performance for a particular month or year. PV performance is largely proportional to the amount of solar radiation received, which may vary from the long-term average by ± 30% for monthly values and ± 10% for yearly values. How the solar radiation might vary for your location may be evaluated by examining the tables in the *Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors* (*http://rredc.nrel.gov/solar/old_data/nsrdb/redbook/*).

For these variations and the uncertainties associated with the weather data and the model used to model the PV performance, future months and years may be encountered where the actual PV performance is less than or greater than the values shown in the table. The variations may be as much as 40% for individual months and up to 20% for individual years. Compared to long-term performance over many years, the values in the table are accurate to within 10% to 12%.

If the default overall DC to AC derate factor is used, the energy values in the table will overestimate the actual energy production if nearby buildings, objects, or other PV modules and array structure shade the PV modules; if tracking mechanisms for one- and two-axis tracking systems do not keep the PV arrays at the optimum orientation with respect to the sun's position; if soiling or snow cover related losses exceed 5%; or if the system performance has degraded from new. (PV performance typically degrades 1% per year.) If any of these situations exist, an overall DC to AC derate factor should be used with PVWATTS that was calculated using system specific component derate factors for *shading*, *sun-tracking*, *soiling*, and *age*.

The PV system size is the nameplate DC power rating. The energy production values in the table are valid only for crystalline silicon PV systems.

The cost savings are determined as the product of the number of kilowatt hours (kWh) and the cost of electricity per kWh. These cost savings occur if the owner uses all the electricity produced by the PV system, or if the owner has a net-metering agreement with the utility. With net-metering, the utility bills the owner for the net electricity consumed. When electricity flows from the utility to the owner, the meter spins forward. When electricity flows from the PV system to the utility, the meter spins backwards.

If net-metering isn't available and the PV system sends surplus electricity to the utility grid, the utility generally buys the electricity from the owner at a lower price than the owner pays the utility for electricity. In this case, the cost savings shown in the table should be reduced.

Besides the cost savings shown in the table, other benefits of PV systems include greater energy independence and a reduction in fossil fuel usage and air pollution. For commercial customers, additional cost savings may come from reducing demand charges. Homeowners can often include the cost of the PV system in their home mortgage as a way of accommodating the PV system's initial cost.

To accelerate the use of PV systems, many state and local governments offer financial incentives and programs. Go to http://www.nrel.gov/stateandlocal for more information.

Appendix 3 German Feed in Tariffs

FIT Germany pre-amendment

German Feed-in Tariffs 2010

The Renewable Energy Sources Act provides for a system of fixed feed-in tariffs for electricity generated from renewable energy sources. The tables below provide an overview of the German feed-in tariffs for facilities commissioned in 2010. For facilities commissioned in 2009, the feed-in tariffs can be found here.

Please note: Some of the details of the feed-in tariffs (e.g. regarding eligibility, bonuses, degression, etc.) are more complicated than they may appear. The tables are merely intended to give an overview. They do not reflect all details of the statutory requirements.

Please also note: The German Bundestag (Parliament) on 6 May 2010 decided to reduce the feed-in tariffs for installations starting operation for the first time after 30 June 2010. The details of the reductions can be found here.

Hydropower (§ 23 EEG)	
Facilities of up to 5 MW – new	
Share of capacity	
Up to 500 kW	12.67
Up to 2 MW	8.65
Up to 5 MW	7.65
Facilities of up to 5 MW – modernised/revitalised	
Share of capacity	
Up to 500 kW	11.67
Up to 5 MW	8.65
Facilities over 5 MW	
Increase in capacity	
Up to 500 kW	7.22
Up to 10 MW	6.26
Up to 20 MW	5.74
Up to 50 MW	4.30
Over 50 MW	3.47
Degression for Hydropower	
Over 5 MW	1 %
Landfill gas, sewage gas and mine gas	
Landfill gas (§ 24 EEG)	
Share of capacity	
Up to 500 kW	8.87
Up to 5 MW	6.07
Sewage gas (§ 25 EEG)	
Share of capacity	

Up to 500 kW	7.00
Up to 5 MW	6.07

Mine gas (§ 26 EEG)

Share of capacity	
Up to 1 MW	7.05
Up to 5 MW	5.08
Over 5 MW	4.10

Bonuses for landfill gas, sewage gas, mine gas

Technology bonus for facilities of up to 5 MW	
Innovative Plant Technology	
Reprocessing facilities for landfill gas and sewage gas	
a) up to a maximum of 350 m³/hour	1.97
b) up to a maximum of 700 m³/hour	0.99

Degression for landfill gas, sewage gas, mine gas

EEG 2009	
Basic Fees and Bonuses	1.5 %

Biomass (§ 27 EEG)

Basic fees

Share of capacity	
Up to 150 kW	11.55
Up to 500 kW	9.09
Up to 5 MW	8.17
Up to 20 MW	7.71

Bonuses for Biomass I

Bonus for the use of renewable raw materials (“Nawaro Bonus”)

Share of capacity up to 150 kW	
Biomass excluding biogas	5.94
Biogas	6.93
- with at least 30% use of farmland manure or slurry	+3.96
- plant material predominantly from landscape conservation	+1.98
Share of capacity up to 500 kW	
solid biomass	5.94
liquid biomass	1)
gas biomass	5.94
Biogas	6.93
- minimum 30% manure	+0.99
- plant material predominantly from landscape conservation	+1.98
Capacity up to 5 MW	
solid biomass	3.96
liquid biomass	01)
gas biomass	3.96
where wood burnt/	2.48

where wood from short rotation coppice and landscape management material burnt	3.96
1) Only for facilities commissioned after 1.1.2009	

Bonuses for Biomass II

Technology bonus for facilities up to 5 MW	
Innovative Plant Technology	
Gas Reprocessing:	
a) up to a maximum of 350 m³/hour	1.98
b) up to a maximum of 700 m³/hour	0.99

Combined heat and power (CHP) bonus (only for the share of feed-in deemed to be CHP electricity)

Up to 20 MW	2.97 2)
2) Also for existing facilities operated as facility 3 CHP for the first time after 31.12.2008. Existing facilities with a capacity up to 500 kW, when the facility 3 requirements are met.	

Degression for Biomass

Basic Fees and Bonuses	1.0%

Geothermal (§ 28 EEG)

Basic Fees

Share of capacity	EEG 2009 3)
Up to 10 MW	15.84
From 10 MW	10.40
3) For installations operating prior to 1.1.2016 the basic fee is raised by 4.00 ct/kWh.	

Bonuses

Heat cogeneration bonus	
Capacity up to 10 MW	2.97
For facilities of up to 10 MW with petrothermal technology	3.96
“Quick Starter Bonus”	3.96

Degression for Geothermal

Basic Fees and Bonuses:	1.0%

Onshore wind (§§ 29, 30 EEG)

Basic Fees

Initial fee (first 5 years from start of operation; plus extension formula time)	9.11
Base fee	4.97

Payments for system services from onshore wind turbine generators

System services bonus	
For facilities commissioned 2002-2008 retrofitted by 1.1.2011	0.70

– payable for 5 yrs

Where new technical requirements for facilities commissioned between 1.1.2009 and 1.1.2014 have been fulfilled, initial fee rises by	0.50
Degression	
Basic Fees and Bonuses:	1.0%
Offshore wind (§ 31 EEG)	
Basic fees	
Initial fee (first 12 years of operation; extension for remote/deep water installations)	13.00
additional 2 ct/kWh where commissioned before 1.1.2016	
Base fee	3.50
Degression	
From 2015	5.0%
Solar radiation (§§ 32, 33 EEG)	
Roof-mounted facilities	
Capacity	
Up to 30 kW	39.14
Up to 100 kW	37.23
Up to 1 MW	35.23
Over 1 MW	29.37
Electricity produced is used within building/facility	
Capacity	
Up to 30 kW	22.76
Freestanding facilities	
Irrespective of capacity (additional requirements apply)	28.43

Degression for solar radiation		
Basic fee & bonuses		
Freestanding Facilities	2010	10.0% 4)
	from 2011	9.0% 4)
Roof Systems up to 100 kW	2010	8.0% 4)
	from 2011	9.0% 4)
Roof Systems over 100 kW	2010	10.0% 4)
	from 2011	9.0% 4)

4) 1% increase/decrease depending on additional installed capacity previous year

Amendment May 2010

German Solar Feed-in Tariff Reduction Mid-2010

After much political debate, the German Bundestag (Parliament) on 6 May 2010 decided on a mid-year reduction of the solar feed-in tariffs. As a consequence, the German solar feed-in tariffs pursuant to the German Renewable Energy Sources Act (EEG) will be adjusted downwards as of 1 July 2010.

Please note that the Bundesrat (Federal Council) invoked the Mediation Committee procedure to reduce the cuts. It is not yet clear when the dispute will be resolved, and when the reductions will enter into force.

Based on the Bundestag's decisions of 6 May 2010, the following key changes will take place:

- Installations attached to or on top of buildings: minus 16% for installations starting operation for the first time after 30 June 2010
- Other installations (in particular freestanding facilities): minus 15% for installations starting operation for the first time after 30 June 2010
    - Transitory provision: no reduction if facility covered by a local development plan (Bebauungsplan) adopted (beschlossen) before 25 March 2010 and in operation before 1 January 2011
- Other facilities on conversion areas from economic, traffic, residential or military use and areas that had already been sealed when the decision to set up or change a building plan was made: minus 11% for installations starting operation for the first time after 30 June 2010
    - Transitory provision: no reduction if facility covered by a local development plan (Bebauungsplan) adopted (beschlossen) before 25 March 2010 and in operation before 1 January 2011
- Other facilities on green areas: only if facility covered by a local development plan (Bebauungsplan) adopted (beschlossen) before 25 March 2010, if area at the time when the decision on drawing up or amending the local development plan was adopted had been used as cropland for the three years preceding this point, and if facility will be in operation before 1 January 2011
- Generated electricity consumed within immediate vicinity of building/facility by operator or third parties for installations up to 500 kW: Payment of feed-in tariffs for consumed electricity, but the applicable feed-in tariffs will be reduced by EUR 0.1638 for up to 30 percent of the generated power and by EUR 0.12 for the remaining power
    - To benefit from this provision, solar installations have to be connected before 1 January 2012
- Increase in 2011 degression if certain additional capacity thresholds are exceeded:
    - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 exceeds 3,500 MW, the 2011 feed-in tariff degression shall increased by 1 percentage points
    - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 exceeds 4,500 MW, the 2011 feed-in tariff degression shall increased by 2 percentage points

  - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 exceeds 5,500 MW, the 2011 feed-in tariff degression shall increased by 3 percentage points

  - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 exceeds 6,500 MW, the 2011 feed-in tariff degression shall increased by 4 percentage points

- Decrease in 2011 degression if additional capacity falls below certain thresholds:

  - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 falls below 2,500 MW, the 2011 feed-in tariff degression shall reduced by 1 percentage points

  - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 falls below 2,000 MW, the 2011 feed-in tariff degression shall reduced by 2 percentage points

  - If capacity registered after 31 May 2010 and before 1 October 2010 multiplied by 3 falls below 1,500 MW, the 2011 feed-in tariff degression shall reduced by 3 percentage points

- Increase in 2012 and later degression if certain additional capacity thresholds are exceeded:

  - If capacity registered in the 12 months until 30 September of the previous year exceeds 3,500 MW, the feed-in tariff degression shall increased by 3 percentage points

  - If capacity registered in the 12 months until 30 September of the previous year exceeds 4,500 MW, the feed-in tariff degression shall increased by 6 percentage points

  - If capacity registered in the 12 months until 30 September of the previous year exceeds 5,500 MW, the feed-in tariff degression shall increased by 9 percentage points

  - If capacity registered in the 12 months until 30 September of the previous year exceeds 6,500 MW, the feed-in tariff degression shall increased by 12 percentage points

- Decrease in 2012 and later degression if additional capacity falls below certain thresholds:

  - If capacity registered in the 12 months until 30 September of the previous year falls below 2,500 MW, the feed-in tariff degression shall reduced by 2.5 percentage points

  - If capacity registered in the 12 months until 30 September of the previous year falls below 2,000 MW, the feed-in tariff degression shall reduced by 5.0 percentage points

  - If capacity registered in the 12 months until 30 September of the previous year falls below 1,500 MW, the feed-in tariff degression shall reduced by 7.5 percentage points

The above changes can be summarised as follows (in ct/kWh):

Capacity/Category	01.01.2010	01.07.2010	01.01.2011*
Up to 30 kW Building	39.14	32.88	29.26
Up to 100 kW Building	37.23	31.27	27.83
Up to 1 MW Building	35.32	29.59	26.34
Over 1 MW Building	29.37	26.14	23.26
Conversion/Sealed Areas	28.43	25.30	22.52
Other Qualified Areas	28.43	24.16	21.50

* Assuming a degression of 11%

Information about earlier proposals to reduce the feed-in tariffs is available here and here.

The amendment to the EEG has not yet been promulgated. Therefore, the reduction technically does not yet have the effect of law.

Appendix 4 Rhur University Report

Included on CD

RUHR
ECONOMIC PAPERS

Manuel Frondel
Nolan Ritter
Christoph M. Schmidt
Colin Vance

Economic Impacts from the Promotion of Renewable Energy Technologies

The German Experience

#156

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The German Experience

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Manuel Frondel, Nolan Ritter, Christoph M. Schmidt, and Colin Vance[1]

Economic Impacts from the Promotion of Renewable Energy Technologies – The German Experience

Abstract

The allure of an environmentally benign, abundant, and cost-effective energy source has led an increasing number of industrialized countries to back public financing of renewable energies. Germany's experience with renewable energy promotion is often cited as a model to be replicated elsewhere, being based on a combination of far-reaching energy and environmental laws that stretch back nearly two decades. This paper critically reviews the current centerpiece of this effort, the Renewable Energy Sources Act (EEG), focusing on its costs and the associated implications for job creation and climate protection. We argue that German renewable energy policy, and in particular the adopted feed-in tariff scheme, has failed to harness the market incentives needed to ensure a viable and cost-effective introduction of renewable energies into the country's energy portfolio. To the contrary, the government's support mechanisms have in many respects subverted these incentives, resulting in massive expenditures that show little long-term promise for stimulating the economy, protecting the environment, or increasing energy security.

JEL Classification: Q28, Q42, Q48

Keywords: Energy policy, energy security, climate, employment

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1. Introduction

The allure of an environmentally benign, abundant, and cost-effective energy source has led an increasing number of industrialized countries to back public financing of renewable energies. For Europe, the European Commission set a target of 20% for the share of electricity from renewable sources by 2020, which is intended to foster compliance with international agreements on greenhouse gas emission reductions[3] and to provide opportunities for employment and regional development (EC 2009:16). These goals are shared by the German Environment Ministry, which regards renewables as a central pillar in efforts to protect the climate, reduce import dependency, and safeguard jobs (BMU 2008:8).

A closer look at Germany's experience, however, whose history of public support for renewable electricity production stretches back nearly two decades, suggests that such emphasis is misplaced. This paper critically reviews the current centerpiece of the German promotion of renewable energy technologies, the Renewable Energy Sources Act (EEG), focusing on its cost and the associated implications for job creation and emissions reductions. The paper will show that, by and large, government policy has failed to harness the market incentives needed to ensure a viable and cost-effective introduction of renewable energies into Germany's energy portfolio. To the contrary, the government's support mechanisms have in many respects subverted these incentives, resulting in massive expenditures that show little long-term promise for stimulating the economy, protecting the environment, or increasing energy security.

The following section describes Germany's growth of electricity production from wind power, photovoltaics (PV) and biomass, the predominant renewable energy sources, together accounting for about 90% of supported renewable electricity production in 2008 (BMU 2009a). Section 3 presents cost estimates of Germany's subsidization of PV modules and wind power plants that were installed between 2000 and 2008, thereby providing for an impression of the resulting long-lasting burden on German electricity consumers. In Section 4, we assess the potential benefits of Germany's subsidization scheme for the global climate, employment, energy security, and technological innovation. The last section summarizes and concludes.

2. Germany's Promotion of Renewable Technologies

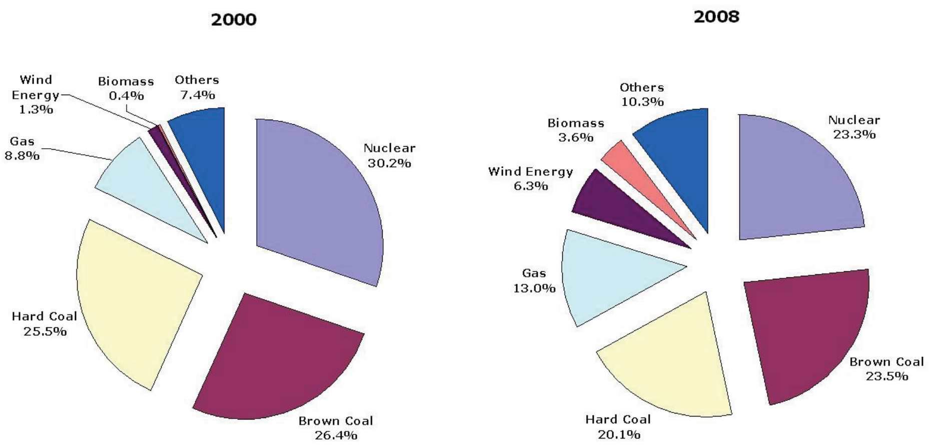
Through generous financial support, Germany has dramatically increased the electricity production from renewable technologies since the beginning of this century (IEA 2007:65). With a share of about 15% of total electricity production in 2008 (Schiffer 2009:58), Germany has more than doubled its renewable electricity production since 2000 and has already significantly exceeded its minimum target of 12.5% set for 2010.

[3] The Commission has stipulated a particularly ambitious target for Germany, aiming to triple the share of renewable sources in the final energy mix from 5.8% in 2005 to 18.0% in 2020.

This increase came at the expense of conventional electricity production, whereby nuclear power experienced the largest relative loss between 2000 and 2008 (Figure 1).

Currently, wind power is the most important of the supported renewable energy technologies: In 2008, the estimated share of wind power in Germany's electricity production amounted to 6.3% (Figure 1), followed by biomass-based electricity generation and water power, whose shares were around 3.6% and 3.1%, respectively. In contrast, the amount of electricity produced through solar photovoltaics (PV) was negligible: Its share was as low as 0.6% in 2008.

Figure 1: Gross Electricity Production in Germany in 2000 and 2008 (AGEB 2009, BMU 2009a)



The substantial contribution of renewable energy technologies to Germany's electricity production is primarily a consequence of a subsidy policy based on feed-in tariffs that was established in 1991, when Germany's Electricity Feed-in Law went into force. Under this law, utilities were obliged to accept and remunerate the feed-in of "green" electricity at 90 percent of the retail rate of electricity, considerably exceeding the cost of conventional electricity generation. An important consequence of this regulation was that feed-in tariffs shrank with the electricity prices in the aftermath of the liberalization of European electricity markets in 1998.

With the introduction of the Renewable Energy Sources Act (EEG), the support regime was amended in 2000 to guarantee stable feed-in tariffs for up to twenty years, thereby providing for favourable conditions for investments in "green" electricity production over the long term. Given the premature over-compliance with the target for 2010, it is not surprising that Germany's EEG is widely considered to be very successful in terms of increasing green electricity shares, and has thus been adopted by numerous other countries, including France, Italy, Spain and the Czech Republic (Voosen 2009).

Under the EEG regime, utilities are obliged to accept the delivery of power from independent producers of renewable electricity into their own grid, thereby paying technology-specific feed-in tariffs far above their production cost of 2 to 7 Cents per kilowatt hour (kWh). With a feed-in tariff of 43 Cents per kWh in 2009, solar electricity is guaranteed by far the largest financial support among all renewable energy technologies (Table 1). Currently, the feed-in tariff for PV is more than eight times higher than the electricity price at the power exchange (Table A1) and more than four times the feed-in tariff paid for electricity produced by on-shore wind turbines (Table 1).

This high support for solar electricity is necessary for establishing a market foothold, with the still low technical efficiencies of PV modules and the unfavorable geographical location of Germany being among a multitude of reasons for solar electricity's grave lack of competitiveness. With the exception of electricity production from large water power stations, other sources of green electricity are also heavily dependent on the economic support stipulated by the EEG. Even on-shore wind, widely regarded as a mature technology, requires feed-in tariffs that exceed the per kWh cost of conventional electricity by up to 300% to remain competitive.

Table 1: Technology-Specific Feed-in Tariffs in Euro Cents per kWh

	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Wind on-shore	9.10	9.10	9.00	8.90	8.70	8.53	8.36	8.19	8.03	9.20
Wind off-shore	9.10	9.10	9.00	8.90	9.10	9.10	9.10	9.10	8.92	15.00
Photovoltaics	50.62	50.62	48.09	45.69	50.58	54.53	51.80	49.21	46.75	43.01
Biomass	10.23	10.23	10.13	10.03	14.00	13.77	13.54	13.32	13.10	14.70
Mean Tariff	8.50	8.69	8.91	9.16	9.29	10.00	10.88	11.36	12.25	--

Sources: BDEW (2001 through 2009), EEG (2000, 2004, 2009)

While utilities are legally obliged to accept and remunerate the feed-in of green electricity, it is ultimately the industrial and private consumers who have to bear the cost through increased electricity prices. In 2008, the price mark-up due to the subsidization of green electricity was about 1.5 Cent per kWh, that is, roughly 7.5% of the average household electricity prices of about 20 Cents per kWh. This price mark-up results from dividing the overall amount of feed-in tariffs of about 9 Bn € (US $12.7 Bn) reported in Table 2 by the overall electricity consumption of 617 Bn kWh (AGEB 2009:22).

Although PV accounted for only 6.2% of renewable electricity production, it is the most privileged technology in terms of highest support per kWh, appropriating 24.6% of the overall feed-in tariffs in 2008 (Table 2). In contrast, the share of hydro power in renewable energy production is 7.0%, but it received only 4.2% of total feed-in tariffs in 2008. Overall, the level of feed-in tariffs increased nearly six-fold between 2001 and 2008, from almost 1.6 to about 9 Bn €.

Some sense for the sheer magnitude of this figure can be gleaned from a comparison with the government's investment in R&D for renewable energies, which we will later argue to be a considerably more cost-effective means of fostering efficiency improvements. In 2007, this investment amounted to 211.1 Mio. € (BMWi 2009), an inconsequential 3% of the total feed-in tariffs of 7.59 Bn € in the same year.

Table 2: Share of Feed-in Tariff Expenditures Allocated to Major Technologies

	2001	2002	2003	2004	2005	2006	2007	2008
Wind Power	-	64.5%	65.1%	63.7%	54.3%	47.1%	44.5%	39.5%
Biomass	-	10.4%	12.5%	14.1%	17.7%	23.0%	27.4%	29.9%
Photovoltaics	-	3.7%	5.9%	7.8%	15.1%	20.3%	20.2%	24.6%
Total in Bn €	1.58	2.23	2.61	3.61	4.40	5.61	7.59	9.02

Sources: BDEW (2001 through 2009) and own calculations.

Along with the significant increase in total tariffs, there was an enormous growth in renewable energy production capacities over the past decade, particularly of wind power (Figure 2). Apart from the U.S., Germany has the largest wind power capacities globally, being almost 24,000 Megawatt (MW) in 2008 (Figure 3). This is one sixth of the overall power capacity of about 150,000 MW in Germany. With respect to PV, Germany's capacity outstrips that of any other country, followed by Spain in second position. In fact, the annual installation of PV capacities almost tripled in the last five years. With 1,500 MW of new installations in 2008, the German market accounted for 42% of the global PV business (REN21 2009:24).

Given the tremendous growth illustrated by Figure 2 and Table 3, it is no wonder that Germany's support scheme based on feed-in tariffs is globally regarded as a great success and that similar promoting instruments for renewable technologies have been implemented elsewhere. The critical issue that will be assessed in the subsequent sections is, however, whether Germany's renewable support scheme is also cost-effective.

Figure 2: Installed Capacities of Wind Power, PV, and Biomass in Germany (BMU 2009a:21)

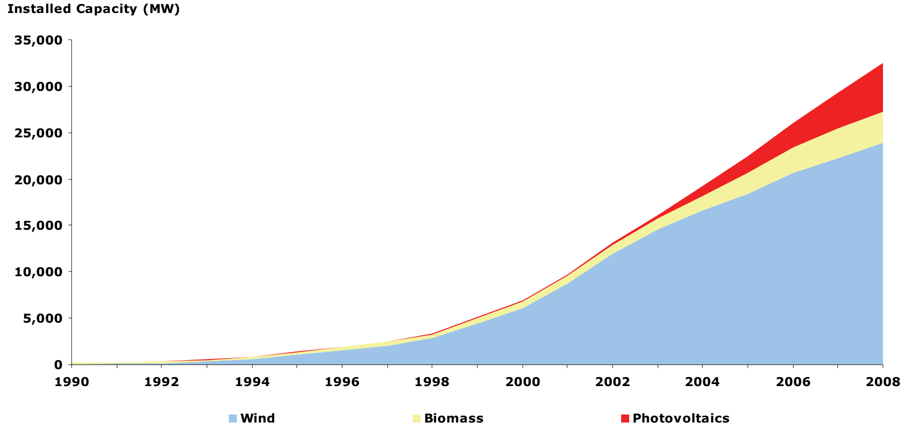
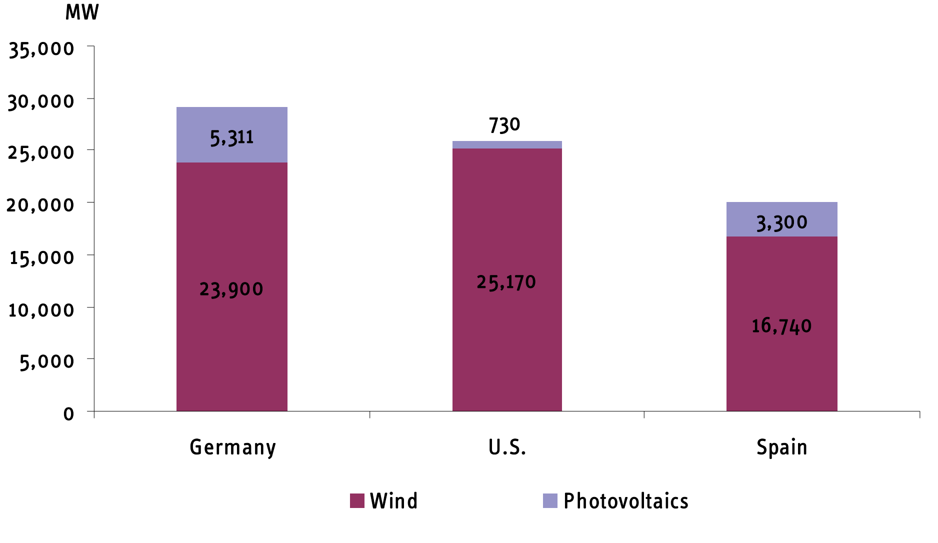


Table 3: Solar Electricity Capacities and Production in Germany

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Capacity Installed, MW	100	178	258	408	1,018	1,881	2,711	3,811	5,311
Annual Increase, MW	-	78	80	150	610	863	830	1,100	1,500
Annual Solar Cell Production in Germany	16	33	54	98	187	319	530	842	1,450

Sources: Production: BMU (2009a), Capacity Installed: BMU (2009a), German Cell Production: BSW (2009).

Figure 3: Installed Capacities of Wind Power and PV in 2008 (REN21)

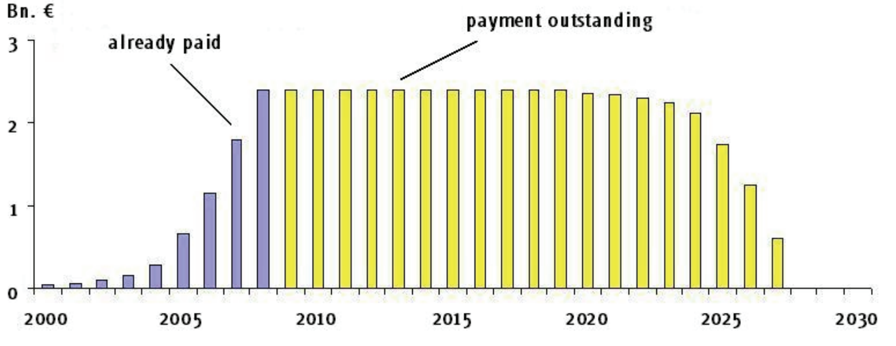


3. Long-Lasting Consequences for Electricity Consumers

The 2009 amendment to Germany's EEG codifies the continued extension of generous financial support for renewable energy technologies over the next decades, with each newly established plant commonly being granted a 20-year period of fixed feed-in tariffs − already an original feature of the EEG when it was enacted in 2000. Hence, in contrast to other subsidy regimes, such as the support of agricultural production under the EU's notoriously protective Common Agricultural Policy, the EEG will have long-lasting consequences. Even if the subsidization regime had ended in 2008, electricity consumers would still be saddled with charges until 2028 (Figure 4). Most disconcertingly, with each year the program is extended, the annual amount of feed-in tariffs for PV increases considerably because of the substantial addition of new cohorts of modules receiving the subsidy, as is displayed in Figure 4 for the case of extending the program to 2010.

In quantifying the extent of the overall burden, we focus on the total net cost of subsidizing electricity production by wind power plants and PV modules both for those plants and modules that were already installed between 2000 and 2008 and for those that may be added in 2009 and 2010. Costs incurred from support of biomass are also substantial, but their quantification is precluded by a highly complex schedule of feed-in tariffs that depend on the concrete technology applied. Moreover, biomass energy generation is widely distributed across a large number of small plants for which no centralized data repository exists.

Figure 4: Annual Amount of Feed-in Tariffs for PV for the cohorts 2000 through 2008



Any assessment of the real net cost induced by subsidizing renewable technologies requires information on the volume of green electricity generation, technology-specific feed-in tariffs, as well as conventional electricity prices, with the specific net cost per kWh being calculated by taking the difference between technology-specific feed-in tariffs and market prices at the power exchange. Our estimates are based on the past electricity production figures for wind and solar electricity for the years 2000 through 2008 and on forecasts of future capacity growth originating from a recent PV study (SARASIN 2007) and a study by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU 2009a). The appendix presents the tables used for our detailed calculations and provides some explanation of their derivation (see also Frondel, Ritter, Schmidt 2008). Past and future market prices for electricity were taken from the "high price scenario" assumed by NITSCH et al. (2005), a study on the future development of renewable energy technologies in Germany.

This price scenario appears to be realistic from the current perspective: real base-load prices are expected to rise from 4.91 Cents per kWh in 2010 (in prices of 2007) to 6.34 Cents per kWh in 2020 (see Table A1). Uncertainties about future electricity prices, however, are hardly critical for the magnitude of our cost estimates, given the large differences between market prices of electricity and, specifically, of the feed-in tariffs for PV, which are as high as 43 Cents per kWh in 2009 (Table A 1).

3.1 Net Cost of Promoting PV

Taking these assumptions and the legal regulations into account and assuming an inflation rate of 2%, which is slightly lower than the average rate since the German reunification, the real net cost for all modules installed between 2000 and 2008 account for about 35 Bn € (in prices of 2007). Future PV installations in 2009 and 2010 may cause further real cost worth 18.3 Bn € (Table 4). Adding both figures yields a total of 53.3 Bn € for PV alone.

Table 4: Net Cost of Promoting PV

	Annual Increase	Nominal Specific Net Cost		Cumulated Net Cost	
		1st year	20th year	Nominal	Real
	Mio kWh	€ Cents/kWh	€ Cents/kWh	Bn €	Bn $€_{2007}$
2000	64	47.99	42.49	0.581	0.559
2001	52	47.94	42.15	0.469	0.442
2002	72	45.36	39.33	0.609	0.563
2003	125	42.90	36.63	0.989	0.897
2004	244	47.74	41.21	2.152	1.913
2005	725	50.23	44.85	6.919	6.027
2006	938	47.30	41.78	8.385	7.164
2007	1,280	44.50	38.86	10.705	8.969
2008	1,310	41.82	36.05	10.282	8.409
Total burden for past installations:				**41.091**	**34.943**
2009	1,600	37.85	31.96	11.269	9.032
2010	1,880	34.16	28.15	11.837	9.296
Total burden at the end of 2010:				**64.197**	**53.272**

Note: Sources of Column 1: 2000-2008: BMU (2009a), 2009-2010: SARASIN (2007). Columns 2 and 3: Differences between feed-in tariffs and market price for the first and the 20th year, respectively. Column 4: Nominal figures of Column 5, using an inflation rate of 2%. Column 5: Last row of Table A2 in the Appendix.

3.2 Net Cost of Promoting Wind Power

The promotion rules for wind power are more subtle than those for PV. While wind energy converters are also granted a 20 year-period of subsidization, the feed-in tariffs are not necessarily fixed over 20 years. In the first 5 years after instalment, each converter receives a relatively high feed-in tariff currently amounting to 9.2 Cents per kWh (Table A1), whereas in the following 15 years the tariff per kWh may be considerably less, depending on the effectiveness of the individual converter. If a converter's electricity output turns out to be low, which is actually the rule rather than the exception, the period of high tariffs can easily stretch to the whole 20 years of subsidization.

As there is no information about how large the share of converters is that are given a prolonged period of high tariffs, in what follows, we calculate both the upper and lower bounds of the net cost of wind electricity generation (Tables 5 and 6). Turning first to the upper-bound case, the net cost of the converters installed between 2000 and 2008 amounts to 19.8 Bn € in real terms if all wind converters were to receive the elevated initial feed-in tariff for 20 years. Future installations in 2009 and 2010 may cause further real cost, so that the wind power subsidies would total 20.5 Bn € if the EEG subsidization were to be abolished at the end of 2010.

Table 5: Net Cost of Promoting Wind Power if elevated tariff holds for 20 years

	Annual Increase	Nominal Specific Net Cost		Cumulated Net Cost	
		1st year	20th year	Nominal	Real
	Bn. kWh	€ Cents/kWh	€ Cents/kWh	Bn €	Bn $€_{2007}$
2000	7.55	6.47	0.97	5.839	5.884
2001	2.96	6.42	0.63	2.116	2.100
2002	5.28	6.27	0.24	3.347	3.281
2003	3.07	6.11	0.00	1.698	1.645
2004	6.65	5.86	0.00	3.032	2.906
2005	1.72	4.23	0.00	0.637	0.603
2006	3.48	3.86	0.00	1.056	0.990
2007	8.79	3.48	0.00	2.134	1.982
2008	2.23	3.10	0.00	0.423	0.389
Total burden for past installations:				**20.282**	**19.780**
2009	1.69	4.04	0.00	0.508	0.450
2010	1.38	3.70	0.00	0.341	0.299
Total burden at the end of 2010:				**21.131**	**20.529**

Note: Sources of Column 1: 2000-2008: BMU (2009a), 2009-2010: SARASIN (2007), Columns 2 and 3: Differences between feed-in tariffs and market price for the first and the 20th year, respectively. Column 4: Nominal figures of Column 5.Column 5: Last row of Table A2 in the Appendix.

Note that, given the assumed price scenario, electricity prices will eventually exceed the feed-in tariffs for wind power, resulting in zero net costs. Referencing the year 2002, for example, the difference between the feed-in tariff for wind converters installed in that year and electricity prices was 6.27 Cents per kWh (Column 2, Table 5). Twenty years hence, in 2021, the difference between the feed-in tariff for these same converters and future conventional electricity costs is projected to be just 0.24 Cents (Column 3, Table 5). By 2022, wind converters that had been installed 2003 are expected to be "competitive" in the sense that feed-in tariffs are then lower than the assumed price of electricity. As a consequence, investors in wind power converters may contemplate selling electricity at the power exchange rather than accepting the then lower tariffs.

Table 6: Net Cost of Promoting Wind Power if the elevated tariff holds for only 5 years

	Annual Increase	Nominal Specific Net Cost		Cumulated Net Cost	
		1st year	20th year	Nominal	Real
	Mio kWh	€ Cents/kWh	€ Cents/kWh	Bn €	Bn $€_{2007}$
2000	7.55	6.47	0.00	3.072	3.320
2001	2.96	6.42	0.00	1.099	1.171
2002	5.28	6.27	0.00	1.719	1.808
2003	3.07	6.11	0.00	0.867	0.899
2004	6.65	5.86	0.00	1.505	1.540
2005	1.72	4.23	0.00	0.327	0.328
2006	3.48	3.86	0.00	0.595	0.585
2007	8.79	3.48	0.00	1.323	1.276
2008	2.23	3.10	0.00	0.290	0.274
Total burden for past installations:				**10.797**	**11.201**
2009	1.69	4.04	0.00	0.297	0.275
2010	1.38	3.70	0.00	0.216	0.196
Total burden at the end of 2010:				**11.310**	**11.672**

Note: Sources of Column 1: 2000-2008: BMU (2009a), 2009-2010: BMU (2008), Columns 2 and 3: Differences between feed-in tariffs and market price for the first and the 20th year, respectively. Column 4: Nominal figures of Column 5.Column 5: Last row of Table A2 in the Appendix.

Should wind converters receive the elevated feed-in tariff for only the first five years, tariffs will reach the electricity price level even earlier. In this lower-bound case, the wind converters installed in 2008 are expected to induce no further cost from 2013 onwards. Accordingly, the total sum of net cost is smaller than in the case of 20 years of elevated feed-in tariffs, amounting to some 11.2 Bn € in real terms for all converters installed between 2000 and 2008. Future installations in 2009 and 2010 may further increase real cost, so that the wind power subsidies may total 11.7 Bn € in real terms, i.e. US $16.6 Bn, at the end of 2010 (Table 6).

In any case, with cumulated real cost ranging between about 11.2 and 19.8 Bn € in 2008, the net cost of promoting wind power is substantially lower than the promotion of PV, whose net cost adds up to much more than 35 Bn € so far and can be expected to rise dramatically. Given the drastic price drop of PV modules of more than 30 % within the first half of 2009, the net cost for subsidizing PV may increase tremendously unless feed-in tariffs are not diminished accordingly in the coming years, with a sky-rocketing demand from Germany as a likely consequence.

Yet, in sharp contrast to the cost of subsidizing PV, which is significantly higher than for wind power, the amount of solar electricity produced is considerably smaller: Our cost estimates for PV modules installed between 2000 and 2008 are based on an overall solar electricity production of 96 Bn kWh during the 20 years of subsidization, while the wind converters installed in the same period of time produce 835 Bn kWh.

3.3 Cost-Effective Climate Protection?

The estimates presented in the previous section clearly demonstrate that producing electricity on the basis of renewable energy technologies is extremely costly. As a consequence, these technologies are far from being cost-effective climate protection measures. In fact, PV is among the most expensive greenhouse gas abatement options: Given the net cost of 41.82 Cents/kWh for modules installed in 2008 (Table 4), and assuming that PV displaces conventional electricity generated from a mixture of gas and hard coal with an emissions factor of 0.584 kg carbon dioxide (CO2) per kWh (Nitsch et al. 2005:66), then dividing the two figures yields abatement costs that are as high as 716 € per tonne.

The magnitude of this abatement cost estimate is in accordance with the IEA's (2007:74) even larger figure of around 1,000 € per tonne, which results from the assumption that PV replaces gas-fired electricity generation. Irrespective of the concrete assumption about the fuel base of the displaced conventional electricity generation, abatement cost estimates are dramatically larger than the current prices of CO2 emission certificates: Since the establishment of the European Emissions Trading System (ETS) in 2005, the price of certificates has never exceeded 30 € per tonne of CO2.

Although wind energy receives considerably less feed-in tariffs than PV, it is by no means a cost-effective way of CO2 abatement. Assuming the same emission factor of 0.584 kg CO2/kWh as above, and given the net cost for wind of 3.10 Cents/kWh in 2008 (Table 6), the abatement cost approximate 54 € per tonne. While cheaper than PV, this cost is still more than threefold the current price of certificates in the ETS. In short, from an environmental perspective, it would be economically much more efficient if greenhouse gas emissions were to be curbed via the ETS, rather than by subsidizing renewable energy technologies such as PV and wind power. After all, it is for efficiency reasons that emissions trading is among the most preferred policy instruments for the abatement of greenhouse gases in the economic literature (Bonus 1998:7).

4 Impacts of Germany's Renewables Promotion

Given the substantial cost associated with Germany's promotion of renewable technologies, one would expect significantly positive impacts on the environment and economic prosperity. Unfortunately, the mechanism by which Germany promotes renewable technologies confers no such benefits.

4.1 Climate Impact

With respect to climate impacts, the prevailing coexistence of the EEG and the ETS means that the increased use of renewable energy technologies attains no additional emission reductions beyond those achieved by ETS alone. In fact, the promotion of renewable energy technologies *ceteris paribus* reduces the emissions of the electricity sector so that obsolete certificates can be sold to other industry sectors that are involved in the ETS. As a result of the establishment of the ETS in 2005, the EEG's true effect is merely a shift, rather than a reduction, in the volume of emissions: Other sectors that are also involved in the ETS emit more than otherwise, thereby outweighing those emission savings in the electricity sector that are induced by the EEG (BMWA 2004:8).

In the end, cheaper alternative abatement options are not realized that would have been pursued in the counterfactual situation without EEG: Very expensive abatement options such as the generation of solar electricity simply lead to the crowding out of cheaper alternatives. In other words, since the establishment of the ETS in 2005, the EEG's net climate effect has been equal to zero[4].

These theoretical arguments are substantiated by the numerical analysis of Traber and Kemfert (2009:155), who find that while the CO2 emissions in Germany's electricity sector are reduced substantially, the emissions are hardly altered at the European scale by Germany's EEG. This is due to the fact that Germany's electricity production from renewable technologies mitigates the need for emission reductions in other countries that participate in the ETS regime, thereby significantly lowering CO2 certificate prices by 15% relative to the situation without EEG (Traber, Kemfert 2009:169). In essence, this permit price effect would lead to an emission level that would be higher than otherwise if it were not outweighed by the substitution effect, that is, the crowding out of conventional electricity production through CO2-free green technologies.

[4] Ultimately, this is because the ETS enforces a binding carbon dioxide emissions cap. It is frequently argued that if the abatement effects of any future promotion of renewable energy technologies have been anticipated and included in the then more ambitious emission cap than otherwise, as is done by the European Commission for the third trading period (2013-2020), the promotion of renewables nevertheless exerts a greenhouse gas effect. This is not true: ETS alone ensures the compliance with the more ambitious emission cap, even if the renewable promotion were to be abolished immediately.

4.2 Electricity Prices

While the EEG's net impact on the European emission level is thus virtually negligible, it increases the consumer prices for electricity in Germany by three percent according to the study of Traber and Kemfert (2009:170). Producer prices, on the other hand, are decreased by eight percent in Germany and by five percent on average in the EU25. As a result, the profits of the majority of the large European utilities are diminished substantially, most notably those of the four dominant German electricity producers. The numerical results indicate that Vattenfall's, Eon's, and RWE's profits are lowered by about 20%, with ENBW's profit loss being seven percent.

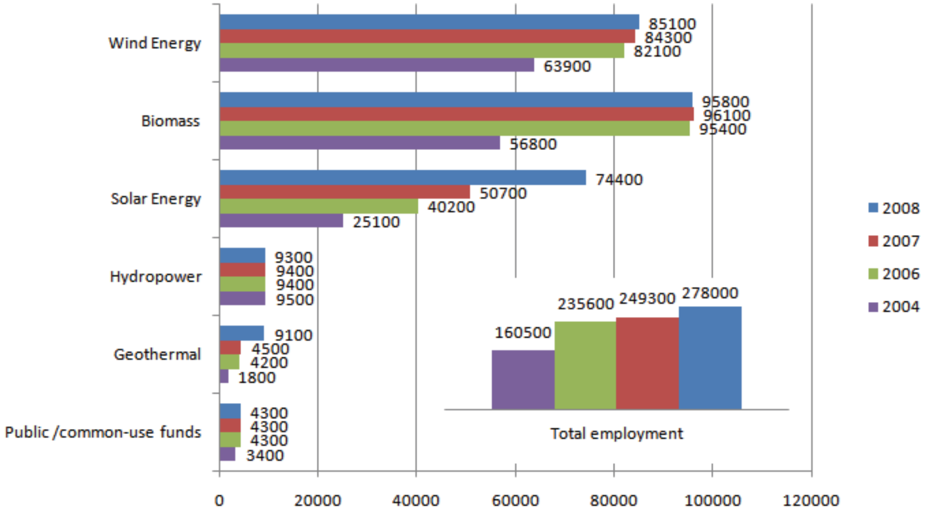
Only those utilities that are operating in non-neighbouring countries, such as Spain or Italy, and whose electricity production is carbon-intensive, benefit from Germany's EEG, as they face lower certificate prices, but do not suffer from a crowding out of conventional production through Germany's green electricity generation. This is why Germany's EEG increases the profits of Italy's Enel and Spain's Endesa by 9% and 16%, respectively (Traber, Kemfert 2009:172).

4.3 Employment Effects

Renewable energy promotion is frequently justified by the associated impacts on job creation. Referring to renewables as a "job motor for Germany," a publication from the Environmental Ministry (BMU) reports a 55% increase in the total number of "green" jobs since 2004, rising to 249,300 by 2007 (BMU 2008b:31). This assessment is repeated in a BMU-commissioned report that breaks down these figures by energy technology (O'Sullivan et al. 2009:9). As depicted in Figure 4, gross employment growth in the solar industry, comprising the photovoltaics and solar collector sectors, has been particularly pronounced, rising by nearly two-fold since 2004 to reach about 74,000 jobs in 2008. Given sustained growth in international demand for renewable energy and an attractive production environment in Germany, the BMU expects these trends to continue: by 2020, upwards of 400,000 jobs are projected in the renewables sector (BMU 2008b:31).

While such projections convey seemingly impressive prospects for gross employment growth, they obscure the broader implications for economic welfare by omitting any accounting of off-setting impacts. The most immediate of these impacts are job losses that result from the crowding out of cheaper forms of conventional energy generation, along with indirect impacts on upstream industries. Additional job losses will arise from the drain on economic activity precipitated by higher electricity prices. In this regard, even though the majority of the German population embraces renewable energy technologies, two important aspects must be taken into account. First, the private consumers' overall loss of purchasing power due to higher electricity prices adds up to billions of Euros. Second, with the exception of the preferentially treated energy-intensive firms, the total investments of industrial energy consumers may be substantially lower. Hence, by constraining the budgets of private and industrial consumers, increased prices ultimately divert funds from alternative, possibly more beneficial, investments. The resulting loss in purchasing power and investment capital causes negative employment effects in other sectors (BMU 2006:3), casting doubt on whether the EEG's employment effects are positive at all.

Figure 4: Gross employment in the renewable energy sector (O'Sullivan et al. 2009:9)



The latest BMU (2009b:36) report acknowledges these cost considerations, and states that "the goal of environmental protection is not primarily to create as many jobs as possible, but rather to reach environmental goals efficiently, that is, at the lowest possible cost to the overall economy". The same report, however, contorts its own logic with the claim that an added benefit of environmental protection is net job creation, because the associated reallocation of resources is typically channelled to labor-intensive renewable sectors (BMU 2009b:36). Such conflating of labor-intensive energy provision with efficient climate protection clouds much of the discussion on the economic merits of renewable energy. In this regard, as Michaels and Murphy (2009) note, proponents of renewable energies often regard the requirement for more workers to produce a given amount of energy as a benefit, failing to recognize that this lowers the output potential of the economy and is hence counterproductive to net job creation.

Several recent investigations of the German experience support such skepticism. Taking account of adverse investment and crowding-out effects, both the IWH (2004) and RWI (2004) find negligible employment impacts. Another analysis draws the conclusion that despite initially positive impacts, the long-term employment effects of the promotion of energy technologies such as wind and solar power systems are negative (BEI 2003:41). Similar results are attained by Fahl et al. (2005), as well as Pfaffenberger (2006) and Hillebrand et al. (2006). The latter analysis, for example, finds an initially expansive effect on net employment from renewable energy promotion resulting from additional investments. By 2010, however, this gives way to a contractive effect as the production costs of power increase.

In contrast, a study commissioned by the BMU (2006:9) comes to the conclusion that the EEG's net employment effect is the creation of up to 56,000 jobs until 2020. This same study, however, emphasizes that positive employment effects critically depend on a robust foreign trade of renewable energy technologies (BMU 2006:7). Whether favourable conditions on the international market prevail for PV, for example, is highly questionable, particularly given negligible or even negative net exports in recent years. While the imports totaled 1.44 Bn €, the exports merely accounted for 0.2 Bn € (BMU 2006:61). Actually, a substantial share of all PV modules installed in Germany originated from imports (BMU 2006:62), most notably from Japan and China. In 2005, the domestic production of modules was particularly low compared with domestic demand. With 319 MW, domestic production only provided for 32% of the new capacity installed in Germany (Table 3). In 2006 and 2007, almost half of Germany's PV demand was covered by imports (Sarasin 2007:19, Table 1). Recent newspaper articles report that the situation remains dire, with the German solar industry facing unprecedented competition from cheaper Asian imports.

Hence, any result other than a negative net employment balance of the German PV promotion would be surprising. In contrast, we would expect massive employment effects in export countries such as China, since these countries do not suffer from the EEG's crowding-out effects, nor from negative income effects. In the end, Germany's PV promotion has become a subsidization regime that, on a per-capita basis, has reached a very high level that by far exceeds average wages: Given our net cost estimate of about 8.4 Bn € for 2008 reported in Table 4, per-capita capita subsidies turn out to be as high as 175,000 € (US $ 257,400), if indeed 48,000 people were employed in the PV sector (BSW Solar 2009).

Even this large figure, however, likely underestimates the true cost of subsidizing employment in this manner, because the new green jobs are filled by workers who were previously employed (Michaels, Murphy 2009:3). Hence, the gross employment effect is overestimated. Moreover, given that the green technology sector needs medium- and high-skilled workers, which have been seriously lacking in Germany in recent years, there is strong competition for such employees, thereby casting further doubt on the net employment effects of the EEG. Finally, it is frequently ignored that other industries, not favored by green subsidies, must draw on a pool of unemployed workers reduced by the EEG, so that job creation in "non-green" sectors may be lower than it otherwise would have been (Michaels, Murphy 2009:3).

4.4 Energy Security

Increased energy security from decreased reliance on fuel imports is another common refrain in support of renewable energy promotion, but one that is predicated on an abundance of sun and wind. As such conditions are highly intermittent in Germany, back-up energy systems that use fossil fuels must consequently be in place to ensure against blackouts. Not only is the maintenance of such systems costly – amounting to some 590 Mio. € in 2006 (Erdmann 2008:32) – but any increased energy security afforded by PV and wind is undermined by reliance on fossil fuel sources – principally gas – that must be imported to meet domestic demand. With some 36% of gas imports originating from Russia (Frondel, Schmidt 2009), a country that has not proven to be a reliable trading partner in recent years, the notion of improved energy security is further called into doubt.

4.5 Technological Innovation

An equally untenable argument points to the alleged long term returns that accrue from establishing an early foothold in the renewable energy market. According to this argument, the support afforded by the EEG allows young firms to expand their production capacities and gain familiarity with renewable technologies, thereby giving them a competitive advantage as the market continues to grow. Progress on this front, however, is critically dependent on creating the incentives conducive to the innovation of better products and production processes.

In this regard, the incentives built into the EEG actually stifle innovation by granting a differentiated system of subsidies that compensates each energy technology according to its lack of competitiveness. This allowed PV to become the big winner in the unlevel playing field thereby created, although it is the most expensive and, hence, most subsidized renewable energy. Rather than affording PV a tremendous advantage, it would make more sense to extend a uniform subsidy per kWh of electricity from renewables. This would harness market forces, rather than political lobbying, to determine which types of renewables could best compete with conventional energy sources.

An additional distortionary feature of the EEG is a degressive system of subsidy rates that decrease incrementally, usually by 5% each year. Although this degression was introduced to create incentives to save cost and innovate, it instead does just the opposite by encouraging the immediate implementation of existing technology. Doing so, helps investors to secure today's favourable subsidy for the next 20 years at an unvaried level, free from the imperative of modernizing with the latest technology. One manifestation of this perverse incentive is bottlenecks in the production of silicium solar cells, whose production cost are a multiple of those of thin film modules.

Even if such a degressive system had spurred the intended cost-saving and technologically benign effects, they would have been counterbalanced by the EEG amendments of 2004 and 2008, which re-established the formerly higher feed-in tariff levels. For example, the 2009 tariffs for electricity produced from biomass and wind converters are above the levels of the year 2000 (Table 1). In other words, the repeated legal amendments have entirely destroyed even the modest cost-diminishing impacts of this degressive system.

This demonstrates that this support mechanism is a classic example of an unsound energy policy that is highly prone to lobbyism. It is very unlikely that such government-directed programs, picking winners and losers, would yield a more efficient energy mix than what would be determined in the market absent massive government intervention (Michaels, Murphy 2009:5).

5 Summary and Conclusion

Although renewable energies have a potentially beneficial role to play as part of Germany's energy portfolio, the commonly advanced argument that renewables confer a double dividend or "win-win solution" in the form of environmental stewardship and economic prosperity is disingenuous. In this article, we argue that Germany's principal mechanism of supporting renewable technologies through feed-in tariffs, in fact, imposes high costs without any of the alleged positive impacts on emissions reductions, employment, energy security, or technological innovation.

First, as a consequence of the prevailing coexistence of the Renewable Energy Sources Act (EEG) and the EU Emissions Trading Scheme (ETS), the increased use of renewable energy technologies triggered by the EEG does not imply any additional emission reductions beyond those already achieved by ETS alone, if the two instruments are not coordinated. This is in line with Morthorst (2003), who analyzes the promotion of renewable energy usage by alternative instruments using a three-country example. If not coordinated, this study's results suggest that renewable support schemes are questionable climate policy instruments in the presence of the ETS.

Second, numerous empirical studies have consistently shown the net employment balance to be zero or even negative in the long run, a consequence of the high opportunity cost of supporting renewable energy technologies. Indeed, it is most likely that whatever jobs are created by renewable energy promotion would vanish as soon as government support is terminated, leaving only Germany's export sector to benefit from the possible continuation of renewables support in other countries such as the US. Third, rather than promoting energy security, the need for backup power from fossil fuels means that renewables increase Germany's dependence on gas imports, most of which come from Russia. And finally, the system of feed-in tariffs stifles competition among renewable energy producers and creates perverse incentives to lock into existing technologies.

Hence, although Germany's promotion of renewable energies is commonly portrayed in the media as setting a "shining example in providing a harvest for the world" (The Guardian 2007), we would instead regard the country's experience as a cautionary tale of massively expensive environmental and energy policy that is devoid of economic and environmental benefits. As other European governments emulate Germany by ramping up their promotion of renewables, policy makers should scrutinize the logic of supporting energy sources that cannot compete on the market in the absence of government assistance.

Nevertheless, government intervention can serve to support renewable energy technologies through other mechanisms that harness market incentives or correct for market failures. The European Trading Scheme, under which emissions certificates are traded, is one obvious example. Another is funding for research and development (R&D), which may compensate for underinvestment from the private sector owing to positive externalities. In the early stages of development of non-competitive technologies, for example, it appears to be more cost-effective to invest in R&D to achieve competitiveness, rather than to promote their large-scale production. This argument seems to be particularly relevant for solar cells, whose technological efficiency is widely known to be modest and, hence, should be first increased substantially via R&D.

Appendix

Table A1: Electricity Prices and Net Cost of PV

	Real Electricity Price	Nominal Electricity Price	Feed-in Tariffs PV	Feed-in Tariffs Wind
	€ $Cents_{2005}$/kWh	€ Cents/kWh	€ Cents/kWh	€ Cents/kWh
2000	2.90	2.63	50.62	9.10
2001	2.90	2.68	50.62	9.10
2002	2.90	2.73	48.09	9.00
2003	2.90	2.79	45.69	8.90
2004	2.90	2.84	50.58	8.70
2005	4.30	4.30	54.53	8.53
2006	4.42	4.50	51.80	8.36
2007	4.53	4.71	49.21	8.19
2008	4.66	4.93	46.75	8.03
2009	4.78	5.16	43.01	9.20
2010	4.91	5.41	39.57	9.11
2011	5.06	5.68	36.01	9.02
2012	5.21	5.96	32.77	8.93
2013	5.36	6.26	29.82	8.84
2014	5.52	6.57	27.13	8.75
2015	5.69	6.90	24.69	8.66
2016	5.81	7.19	22.47	8.57
2017	5.94	7.49	20.45	8.48
2018	6.07	7.80	18.61	8.40
2019	6.20	8.13	16.93	8.32
2020	6.34	8.47	15.41	8.24

Table A2: Net Cost in € Cents$_{2007}$ per kWh by Cohort for PV

Cohort	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	55.13										
2001	53.99	53.99									
2002	52.87	52.87	50.08								
2003	51.78	51.78	49.04	46.44							
2004	50.70	50.70	48.02	45.47	50.66						
2005	48.19	48.19	45.56	43.06	48.15	52.26					
2006	47.04	47.04	44.46	42.01	47.00	51.03	48.24				
2007	45.91	45.91	43.38	40.98	45.87	49.82	47.09	44.5			
2008	44.79	44.79	42.31	39.96	44.75	48.62	45.95	43.41	41.00		
2009	43.69	43.69	41.26	38.95	43.65	47.45	44.82	42.34	39.98	36.38	
2010	42.61	42.61	40.22	37.96	42.57	46.29	43.72	41.27	38.96	35.43	32.19
2011	41.52	41.52	39.18	36.97	41.48	45.13	42.61	40.21	37.94	34.49	31.31
2012	40.45	40.45	38.16	35.98	40.41	43.99	41.52	39.17	36.94	33.56	30.44
2013	39.39	39.39	37.15	35.01	39.36	42.86	40.44	38.14	35.95	32.63	29.58
2014	38.35	38.35	36.15	34.06	38.31	41.75	39.37	37.12	34.98	31.72	28.73
2015	37.32	37.32	35.16	33.11	37.28	40.65	38.32	36.11	34.01	30.82	27.88
2016	36.34	36.34	34.23	32.22	36.31	39.61	37.33	35.16	33.34	30.22	27.34
2017	35.38	35.38	33.31	31.34	35.35	38.59	36.35	34.23	32.45	29.38	26.56
2018	34.44	34.44	32.40	30.47	34.40	37.58	35.39	33.55	31.58	28.57	25.80
2019	33.50	33.50	31.51	29.62	33.47	36.59	34.43	32.65	30.71	27.76	25.05
2020		32.58	30.63	28.77	32.55	35.61	33.50	31.76	29.85	26.96	24.30
2021			29.81	27.99	31.70	34.69	32.62	30.88	29.01	26.18	23.57
2022				27.22	30.85	33.79	31.76	30.05	28.23	25.45	22.89
2023					30.02	32.90	30.91	29.25	27.46	24.73	22.22
2024						32.03	30.08	28.45	26.70	24.02	21.57
2025							29.26	27.68	25.95	23.34	20.93
2026								26.90	25.21	22.65	20.28
2027									24.50	21.98	19.66
2028										21.32	19.05
2029											18.45
Bn kWh	0.064	0.052	0.072	0.125	0.244	0.725	0.938	1.280	1.310	1.600	1.880
Bn €	0.559	0.442	0.563	0.897	1.913	6.027	7.164	8.969	8.409	9.032	9.296

The specific net cost is calculated by subtracting actual or expected market prices of electricity from feed-in tariffs. While tariffs are fixed for each cohort of installed solar modules for a period of 20 years, of course, market prices change over time. Therefore, the specific net cost per kWh varies accordingly. The cumulative net cost induced by an individual cohort, reported in the last row, results from adding up the products of the real net cost per kWh and the solar electricity produced by each cohort displayed in the penultimate row. Net cost for wind is calculated in the same manner.

Table A3: Net Cost in € Cents$_{2007}$ per kWh by Cohort for Wind Power (elevated tariff for 20 years)

Cohort	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	7.44										
2001	7.23	7.23									
2002	7.03	7.03	6.92								
2003	6.83	6.83	6.72	6.62							
2004	6.64	6.64	6.53	6.43	6.22						
2005	4.99	4.99	4.89	4.79	4.58	4.40					
2006	4.69	4.69	4.59	4.49	4.28	4.11	3.94				
2007	4.39	4.39	4.29	4.19	3.99	3.82	3.65	3.48			
2008	4.08	4.08	3.99	3.89	3.69	3.53	3.36	3.19	3.04		
2009	3.78	3.78	3.69	3.59	3.40	3.23	3.07	2.91	2.75	3.88	
2010	3.48	3.48	3.39	3.29	3.10	2.94	2.78	2.62	2.47	3.57	3.49
2011	3.16	3.16	3.07	2.98	2.79	2.64	2.48	2.32	2.17	3.25	3.17
2012	2.84	2.84	2.75	2.66	2.48	2.33	2.17	2.02	1.87	2.93	2.85
2013	2.52	2.52	2.43	2.35	2.17	2.02	1.87	1.72	1.57	2.61	2.53
2014	2.20	2.20	2.11	2.03	1.85	1.71	1.56	1.41	1.27	2.29	2.21
2015	1.88	1.88	1.79	1.71	1.54	1.39	1.25	1.10	0.97	1.96	1.89
2016	1.60	1.60	1.52	1.43	1.27	1.12	0.98	0.84	0.71	1.40	1.61
2017	1.32	1.32	1.24	1.16	0.99	0.85	0.72	0.58	0.44	1.12	1.33
2018	1.04	1.04	0.96	0.88	0.72	0.59	0.45	0.31	0.18	0.84	1.05
2019	0.77	0.77	0.69	0.61	0.45	0.32	0.18	0.00	0.00	0.57	0.77
2020		0.49	0.41	0.33	0.18	0.05	0.00	0.00	0.00	0.34	0.50
2021			0.18	0.11	0.00	0.00	0.00	0.00	0.00	0.11	0.27
2022				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
2023					0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024						0.00	0.00	0.00	0.00	0.00	0.00
2025							0.00	0.00	0.00	0.00	0.00
2026								0.00	0.00	0.00	0.00
2027									0.00	0.00	0.00
2028										0.00	0.00
2029											0.00
Bn kWh	7.55	2.96	5.28	3.07	6.65	1.72	3.48	8.79	2.23	1.69	1.38
Bn €	5.884	2.100	3.281	1.645	2.906	0.603	0.990	1.982	0.389	0.450	0.299

Table A4: Net Cost in € Cents2007 per kWh by Cohort for Wind Power (elevated tariff for five years)

Cohort	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	7.44										
2001	7.23	7.23									
2002	7.03	7.03	6.92								
2003	6.83	6.83	6.72	6.62							
2004	6.64	6.64	6.53	6.43	6.22						
2005	1.97	4.99	4.89	4.79	4.58	4.40					
2006	1.72	1.72	4.59	4.49	4.28	4.11	3.94				
2007	1.48	1.48	1.39	4.19	3.99	3.82	3.65	3.48			
2008	1.23	1.23	1.14	1.05	3.69	3.53	3.36	3.19	3.04		
2009	0.99	0.99	0.90	0.80	0.32	3.23	3.07	2.91	2.75	3.88	
2010	0.74	0.74	0.65	0.56	0.09	0.00	2.78	2.62	2.47	3.57	3.49
2011	0.47	0.47	0.39	0.30	0.00	0.00	0.00	2.32	2.17	3.25	3.17
2012	0.21	0.21	0.13	0.04	0.00	0.00	0.00	0.00	1.87	2.93	2.85
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.61	2.53
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.21
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023					0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024						0.00	0.00	0.00	0.00	0.00	0.00
2025							0.00	0.00	0.00	0.00	0.00
2026								0.00	0.00	0.00	0.00
2027									0.00	0.00	0.00
2028										0.00	0.00
2029											0.00
Bn kWh	7.55	2.96	5.28	3.07	6.65	1.72	3.48	8.79	2.23	1.69	1.38
Bn €	3.32	1.17	1.81	0.90	1.54	0.33	0.59	1.28	0.27	0.28	0.20

Table A5: Annual Net Cost in Bn $€_{2007}$ per Annum and by Cohort for PV

Cohort	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
2000	0.04											0.04
2001	0.03	0.03										0.06
2002	0.03	0.03	0.04									0.10
2003	0.03	0.03	0.04	0.06								0.15
2004	0.03	0.03	0.03	0.06	0.12							0.27
2005	0.03	0.03	0.03	0.05	0.12	0.38						0.64
2006	0.03	0.02	0.03	0.05	0.11	0.37	0.45					1.08
2007	0.03	0.02	0.03	0.05	0.11	0.36	0.44	0.57				1.62
2008	0.03	0.02	0.03	0.05	0.11	0.35	0.43	0.56	0.54			2.12
2009	0.03	0.02	0.03	0.05	0.11	0.34	0.42	0.54	0.52	0.58		2.65
2010	0.03	0.02	0.03	0.05	0.10	0.34	0.41	0.53	0.51	0.57	0.61	3.19
2011	0.03	0.02	0.03	0.05	0.10	0.33	0.40	0.51	0.50	0.55	0.59	3.10
2012	0.03	0.02	0.03	0.04	0.10	0.32	0.39	0.50	0.48	0.54	0.57	3.02
2013	0.03	0.02	0.03	0.04	0.10	0.31	0.38	0.49	0.47	0.52	0.56	2.94
2014	0.02	0.02	0.03	0.04	0.09	0.30	0.37	0.48	0.46	0.51	0.54	2.86
2015	0.02	0.02	0.03	0.04	0.09	0.29	0.36	0.46	0.45	0.49	0.52	2.78
2016	0.02	0.02	0.02	0.04	0.09	0.29	0.35	0.45	0.44	0.48	0.51	2.73
2017	0.02	0.02	0.02	0.04	0.09	0.28	0.34	0.44	0.43	0.47	0.50	2.65
2018	0.02	0.02	0.02	0.04	0.08	0.27	0.33	0.43	0.41	0.46	0.49	2.58
2019	0.02	0.02	0.02	0.04	0.08	0.27	0.33	0.42	0.40	0.44	0.47	2.51
2020		0.02	0.02	0.04	0.08	0.26	0.32	0.41	0.39	0.43	0.46	2.42
2021			0.02	0.04	0.08	0.25	0.31	0.40	0.38	0.42	0.44	2.33
2022				0.03	0.08	0.25	0.30	0.38	0.37	0.41	0.43	2.25
2023					0.07	0.24	0.29	0.37	0.36	0.40	0.42	2.15
2024						0.23	0.28	0.36	0.35	0.38	0.41	2.02
2025							0.28	0.35	0.34	0.37	0.39	1.74
2026								0.34	0.33	0.36	0.38	1.42
2027									0.32	0.35	0.37	1.04
2028										0.34	0.36	0.70
2029											0.35	0.35
Total	0.56	0.44	0.56	0.90	1.91	6.03	7.16	8.97	8.41	9.03	9.30	53.27

The columns in Table A5 inform about the net cost per cohort of annually installed modules, while the rows show the real net cost per year. A particularly striking result of the presentation is the dramatic cost increase related to the cohort installed in 2005, the year following the EEG amendment in 2004. Annual net cost for wind is calculated in the same manner.

Table A6: Annual Net Cost in Bn €$_{2007}$ per Annum and by Cohort for Wind Power (elevated tariff for 20 years)

Cohort	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
2000	0.56											0.69
2001	0.55	0.21										0.96
2002	0.53	0.21	0.37									1.43
2003	0.52	0.20	0.35	0.20								1.70
2004	0.50	0.20	0.34	0.20	0.41							2.28
2005	0.38	0.15	0.26	0.15	0.30	0.08						2.43
2006	0.35	0.14	0.24	0.14	0.28	0.07	0.14					2.72
2007	0.33	0.13	0.23	0.13	0.27	0.07	0.13	0.31				3.44
2008	0.31	0.12	0.21	0.12	0.25	0.06	0.12	0.28	0.07			3.62
2009	0.29	0.11	0.19	0.11	0.23	0.06	0.11	0.26	0.06	0.07		3.62
2010	0.26	0.10	0.18	0.10	0.21	0.05	0.10	0.23	0.06	0.06	0.05	3.62
2011	0.24	0.09	0.16	0.09	0.19	0.05	0.09	0.20	0.05	0.06	0.04	3.62
2012	0.21	0.08	0.15	0.08	0.17	0.04	0.08	0.18	0.04	0.05	0.04	3.62
2013	0.19	0.07	0.13	0.07	0.14	0.03	0.06	0.15	0.04	0.04	0.03	3.62
2014	0.17	0.07	0.11	0.06	0.12	0.03	0.05	0.12	0.03	0.04	0.03	3.62
2015	0.14	0.06	0.09	0.05	0.10	0.02	0.04	0.10	0.02	0.03	0.03	3.62
2016	0.12	0.05	0.08	0.04	0.08	0.02	0.03	0.07	0.02	0.03	0.02	3.62
2017	0.10	0.04	0.07	0.04	0.07	0.01	0.02	0.05	0.01	0.02	0.02	3.62
2018	0.08	0.03	0.05	0.03	0.05	0.01	0.02	0.03	0.00	0.02	0.01	3.62
2019	0.06	0.02	0.04	0.02	0.03	0.01	0.01	0.00	0.00	0.01	0.01	3.62
2020		0.01	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	2.93
2021			0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	2.66
2022				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.19
2023					0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.92
2024						0.00	0.00	0.00	0.00	0.00	0.00	1.34
2025							0.00	0.00	0.00	0.00	0.00	1.19
2026								0.00	0.00	0.00	0.00	0.90
2027									0.00	0.00	0.00	0.18
2028										0.00	0.00	0.00
2029											0.00	0.00
Total	5.88	2.10	3.28	1.65	2.91	0.60	0.99	1.98	0.39	0.45	0.30	20.53

Table A7: Annual Net Cost in Bn $€_{2007}$ per Annum and by Cohort for Wind Power (elevated tariffs for five years)

Cohort	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
2000	0.56											0.56
2001	0.55	0.21										0.76
2002	0.53	0.21	0.37									1.10
2003	0.52	0.20	0.35	0.20								1.28
2004	0.50	0.20	0.34	0.20	0.41							1.65
2005	0.15	0.15	0.26	0.15	0.30	0.08						1.08
2006	0.13	0.05	0.24	0.14	0.28	0.07	0.14					1.05
2007	0.11	0.04	0.07	0.13	0.27	0.07	0.13	0.31				1.12
2008	0.09	0.04	0.06	0.03	0.25	0.06	0.12	0.28	0.07			0.99
2009	0.07	0.03	0.05	0.02	0.02	0.06	0.11	0.26	0.06	0.07		0.74
2010	0.06	0.02	0.03	0.02	0.01	0.00	0.10	0.23	0.06	0.06	0.05	0.63
2011	0.04	0.01	0.02	0.01	0.00	0.00	0.00	0.20	0.05	0.06	0.04	0.43
2012	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.04	0.16
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.03	0.08
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024						0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025							0.00	0.00	0.00	0.00	0.00	0.00
2026								0.00	0.00	0.00	0.00	0.00
2027									0.00	0.00	0.00	0.00
2028										0.00	0.00	0.00
2029											0.00	0.00
Total	3.32	1.17	1.81	0.90	1.54	0.33	0.59	1.28	0.27	0.28	0.20	11.67

Table A8 shows the cost of subsidisation in € Cents/kWh for the years 2000 through 2008 that were calculated by dividing the total amount of feed-in tariffs by the gross electricity consumption.

Table A8: Effect of Subsidization on Electricity Prices

	Electricity Consumption Bn. kWh	Feed-in Tariffs Bn. Euro	Cost of Subsidization € Cents/kWh
2000	579.6	0.87	0.15
2001	585.1	1.58	0.27
2002	587.4	2.23	0.38
2003	598.6	2.61	0.44
2004	608.0	3.61	0.59
2005	612.1	4.40	0.72
2006	617.0	5.61	0.91
2007	618.4	7.59	1.23
2008	616.6	9.02	1.46

Sources: AGEB (2009), BDEW (2001 through 2009)

Total feed-in tariffs for each cohort of newly installed PV modules and wind converters are displayed in the last columns of Tables A9 through A11 and calculated by assuming that the same annual amount of electricity is produced over the whole subsidization period of 20 years.

Table A9: Total feed-in tariffs for PV

	Annual Increase, Mio kWh	Specific Feed-in Tariff, € Cents/kWh	Annual Amount of Feed-in Tariffs, Mio €	Cumulated over 20 years Nominal Bn €	Real Bn $€_{2007}$
2000	64	50.62	32.4	0.648	0.671
2001	52	50.62	26.3	0.526	0.494
2002	72	48.09	34.6	0.692	0.638
2003	125	45.69	57.1	1.142	1.031
2004	244	50.58	123.4	2.468	2.184
2005	725	54.53	395.3	7.906	6.680
2006	938	51.80	485.9	9.717	8.266
2007	1,280	49.21	629.9	12.598	10.506
2008	1,310	46.75	612.4	12.248	10.014
Total burden for past installations:				**47.945**	**40.484**
2009	1,600	43.01	688.2	13.764	11.032
2010	1,880	39.57	743.9	14.878	11.692
Total burden at the end of 2010:				**76.587**	**63.208**

Note: Column 1: 2000-2008: BMU (2009a), 2009-2010: SARASIN (2007). Column 2: Feed-in tariff for PV in € cents per kWh. Column 3: Product of Column 1 and 2. Column 4: Column 3 times 20. Column 5: Inflation-corrected figures of Column 4 using a rate of 2%.

Table A10: Total feed-in tariffs for Wind Power (elevated tariff for twenty years)

	Annual Increase, Mio kWh	Feed-in Tariff, € Cents/kWh	Cumulated over 20 years	
			Nominal Bn. €	Real Bn. $€_{2007}$
2000	7.55	9.10	13.74	13.16
2001	2.96	9.10	5.39	5.06
2002	5.28	9.00	9.50	8.75
2003	3.07	8.90	5.47	4.94
2004	6.65	8.70	11.57	10.24
2005	1.72	8.53	2.93	2.55
2006	3.48	8.36	5.82	4.95
2007	8.79	8.19	14.40	12.01
2008	2.23	8.03	3.58	2.93
Total burden for past installations:			**72.40**	**64.59**
2009	1.69	9.20	3.12	2.50
2010	1.38	9.11	2.51	1.97
Total burden at the end of 2010:			**78.03**	**69.06**

Note: Column 1: 2000-2008: BMU (2009a), 2009-2010: BMU (2008), Column 2: Feed-in tariff for PV in € cents per kWh. Column 3: Product of Column 1 and 2. Column 4: Column 3 times 20. Column 5: Inflation-corrected figures of Column 4 using a rate of 2%.

Table A11: Total feed-in tariffs for Wind Power (elevated tariff for first five years)

	Annual Increase,	Feed-in Tariff, first 5 years,	Feed-in Tariff, last 15 years,	Cumulated over 20 years	
	Mio kWh	€ Cents/kWh	€ Cents/kWh	Bn. €	Bn. $€_{2007}$
2000	7.55	9.10	6.19	10.45	10.17
2001	2.96	9.10	6.19	4.09	3.91
2002	5.28	9.00	6.10	7.20	6.74
2003	3.07	8.90	6.00	4.13	3.79
2004	6.65	8.70	5.50	8.38	7.56
2005	1.72	8.53	5.39	2.12	1.88
2006	3.48	8.36	5.28	4.21	3.65
2007	8.79	8.19	5.17	10.42	8.86
2008	2.23	8.03	5.07	2.59	2.16
Total burden for past installations:				**53.59**	**48.72**
2009	1.69	9.20	5.02	2.05	1.69
2010	1.38	9.11	4.97	1.65	1.33
Total burden at the end of 2010:				**57.29**	**51.74**

Note: Column 1: 2000-2008: BMU (2009a), 2009-2010: BMU (2008), Column 2: Feed-in tariff for PV in € cents per kWh. Column 3: Product of Column 1 and 2. Column 4: Column 3 times 20. Column 5: Inflation-corrected figures of Column 4 using a rate of 2%.

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Appendix 5 Commentary on the German FIT experience

FIT Reductions Germany

Proposed reductions to the tariff Germany pays to generators of solar power have alarmed the country's PV industry. Its worries include big job losses and a crippling loss of competitiveness.

by David Appleyard, Associate Editor, Renewable Energy World Magazine

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London, UK — With some irony, it appears that the success of German's solar photovoltaic (PV) feed-in tariffs, enshrined in the Renewable Energy Sources Act, or Erneuerbare-Energien-Gesetz (EEG), has lead to the federal government's proposal to cut them.

Berlin has decided to accelerate the annual rate by which it will reduce the solar feed-in tariff from five percent to ten percent, partly because the overwhelming success of the scheme lead to concerns that its generous support was causing a proliferation of solar installations that were becoming less affordable as the German economy entered recession.

The success of the scheme has meant many more installations than expected have secured support under the EEG. Given the lower initial expectations, the subsequently much larger number of qualifying installations has taxed the allocated budget. With the economy in decline, this has meant the generosity of the scheme has become less affordable.

Consequently, the government cut the tariff for new solar plants by around 10 per cent on 1 January 2010. However, at around the same time as the shrinking of Germany's economy in 2009, the price of silicon went into a slump, which in turn led to significant reductions in installation costs. Calls followed for a further reduction in the feed-in tariffs.

In response, the Ministry for the Environment released plans in January to reduce solar funding by a further 15 per cent in the summer of 2010 and by that amount again at the start of 2011 – this is in addition to reductions already planned.

Although the amendments are not yet law as the coalition government is still negotiating on the draft-proposal, reports in the media suggest that roof systems will receive 16 per cent less in feed-in tariff in June, in addition to the January cut of 10 per cent. They will also suffer a two per cent cut per 1000 MW of newly installed capacity should the market raise above a certain – currently < – limit.

The thinking is that as the volume of installations increases overtime, costs will fall. A final parliamentary decision on the new tariff rates is expected soon.

Tariff Amendments Draw Fire

Proposed changes to the feed-in tariff in Germany for solar power have caused so much alarm in the PV industry there that the head of the country's solar industry association has issued a strong warning about its possible effects. Günther Cramer, president of the Bundesverband Solarwirtschaft (BSW), went so far as to say that the proposed cuts threaten jobs. "Dozens of German solar companies would face insolvency or be forced to relocate their production outside of Germany," said Cramer.

“The excessive feed-in tariff cut endangers one of the most important driving forces of jobs and the economy in our country. The creation of value added in the production of PV modules must be allowed to continue in Germany.” Cramer added the cuts even threaten to make the German chancellor’s policy on climate change obsolete. The BSW strongly advises a cautionary approach to reducing the feed-in tariff.

It says large sections of the German solar industry would not survive an additional reduction of the tariff for photovoltaic systems this year in the double-digit percentage range. “If this were implemented, around 50 000 jobs in Germany would hang in the balance,” a statement by the organisation reads.

BSW managing director Carsten Körnig reflected the industry’s consternation over these proposals by saying: “Depending on growth and market segment, this brings the total reduction in funding for solar energy from 31 December 2009 to 1 January 2011 from 25.5 to 55 per cent.”

Wider changes to to global PV market have not helped either. With the rise of low-cost manufacturers in Asia, chiefly China, Germany’s solar companies were already worried about their competitiveness and technological leadership. The BSW is now warning of a wave of insolvencies in the PV industry as well as the loss of tens of thousands of jobs if the drastic cuts in the feed-in tariff are implemented. “Such a radical and sudden incision robs German solar companies of the foundations of their business. They are left with no scope for investment in order to survive in the harsh international competition,” said Carsten Körnig.

A recent analysis paper by Landesbank Baden-Württemberg (LBBW) cited by the BSW states that a reduction of the solar feed-in tariff in the double-digit percentage range would mean: “that it is over for the European production location”.

A tariff reduction will also benefit East Asian competitors, which would make great gains in market share, the LBBW analysis added. The principal reason for this is the exchange rate advantages and undervaluation of the Chinese currency. In addition the paper by LBBW finds that with a further double-digit percentage reduction of the feed-in tariff, project returns would fall below the 6–7 per cent mark, an amount analysts consider to be critical. “This is the necessary minimum to offer a sufficient investment incentive to purchasers of new photovoltaic systems and offset the operating risk,” says Körnig.

Grid Parity and PV investment

According to Germany’s solar industry, it is working to continually reduce its production costs. If development is maintained at the current pace, solar power will reach ordinary retail prices or grid-parity by 2013. To achieve this, it plans to invest €10 billion ($13.6 billion) in the expansion of solar manufacturing capacity and in research in Germany over the next three years or so. But, Cramer observes, “To do this, we need political backing and a reliable support policy with a sense of proportion.”

Nonetheless, BSW does consider a quicker reduction of the solar feed-in tariff to be possible, conceding that the EEG is effectively too generous and suggesting alternative amendments. However, the association believes that additional reductions should be based on the extent of additional market growth.

Beyond the two already approved feed-in tariff reductions of around ten per cent each at the start of 2010 and 2011, the industry says that there is no scope for further cuts of the order of double digit percentages in the short-term.

Even with strong market growth, the tariff should fall by no more than 14 per cent per year, the BSW says, adding this would leave scope for a further reduction of some five per cent this summer.

Evidently, says the BSW, an amendment to the minister for the environment Dr Norbert Röttgen’s plan is essential. As an alternative the industry has proposed a one-off reduction of 15–25 per cent by the summer of 2010. Furthermore, the industry proposes that at the start of 2011, the annual reduction of nine per cent already established in the EEG could be made in addition to a tariff reduction of up to ten per cent.

This, BSW says, will allow a gradual and growth-dependent reduction of the solar feed-in tariff by 9-14 per cent per year and, the industry believes, would ensure that the economic efficiency of operating solar arrays in all market segments is maintained.

Without confirmation of either the plans by the environment ministry or the industry's alternatives, doubt has already been cast on suggestions that the solar energy industry will manage to invest the €10 billion outlined, a figure double that of the previous four years that equates to some 14 per cent of the industry's turnover.

FIT_UK

When the German programme began in 2000, it offered index-linked payments of 51 euro cents for every KWh of electricity produced by solar PV. These were guaranteed for 20 years. This is similar to the UK's initial subsidy, of 41p. As in the UK, the solar subsidy was, and remains, massively greater than the payments for other forms of renewable technology.

The real net cost of the solar PV installed in Germany between 2000 and 2008 was €35bn. The paper estimates a further real cost of €18bn in 2009 and 2010: a total of €53bn in ten years. These investments make wonderful sense for the lucky householders who could afford to install the panels, as lucrative returns are guaranteed by taxing the rest of Germany's electricity users. But what has this astonishing spending achieved? By 2008 solar PV was producing a grand total of 0.6% of Germany's electricity. 0.6% for €35bn. Hands up all those who think this is a good investment.

After years of these incredible payments, and the innovation and cost reductions they were supposed to stimulate, the paper estimates that saving one tonne of carbon dioxide through solar PV in Germany still costs €716. The International Energy Agency has produced an even higher estimate: €1000 per tonne. There are dozens of ways in which you can save carbon for 100th of the cost of solar PV at high latitudes.

The Ruhr University paper comes out against using feed-in tariffs to stimulate wind power as well, but in this case it shows that large-scale wind power in Germany is likely to become cheaper than conventional power by 2022, at which point subsidies will become redundant. It makes no such prediction for solar PV. It reinforces the point I made in my first sally: while Germany, like the UK, belongs to the European emissions trading scheme, any carbon savings made by feed-in tariffs merely allow polluting industries to raise their emissions. The net saving is zero. The paper suggests that a far more cost-effective mechanism would be to crank down the emissions cap under the trading scheme – then let renewable technologies fight it out to offer the biggest carbon saving per euro.

Germany's feed in tariffs were designed to supply 12% of Germany's electricity from renewable sources by 2010. This target was passed three years early and today 15% of Germany's electricity is renewable. Around 1% of this renewable electricity comes from solar. Germany is now a leading destination for green capital; by 2020 green technology is expected pass the auto and electrical engineering industries to become the nation's top employer.

Germany implemented a feed in tariff which supported wind and hydro power in 1991. This scheme was expanded in 2000 to include all sources of renewable energy and to tie the premium paid to the cost of energy production. To create parity between different technologies, the new premium varied for each renewable energy source. The forms of renewable energy which were the most costly received the highest premium, e.g. rooftop solar.

The scheme is designed to reduce the premium as the costs of production for each technology decreases. As a result, the premium for roof top solar panels will be reduced by 16% this year.

Spain

In 2007, Spain announced the world's most generous feed in tariff for solar generated electricity. Providing US 58c/kWh, the scheme caused immediate growth in installed solar power capacity. By the end of 2007, Spain had reached its 2010 goal to produce 400 MW of electricity from solar panels. In 2008 Spain connected an additional 2.5 GW of solar power into its grid, making it second in the world only to Germany.

Although this scheme achieved the objective of growing the country's solar capacity, it inflated the cost of solar installations at a time when they were falling elsewhere in the world. This meant that even inefficient and poorly sited installations were profitable. The massive growth in solar energy also caused a large rise in consumer electricity bills which included a surcharge to fund the feed in tariff.

In response, the Spanish Government slashed its feed in tariff causing solar manufacturing and installation companies across the country to collapse, destroying thousands of jobs. Its current 39c/kWh premium is now adjusted quarterly.

German solar feed-in tariff to sink another 15%

22 January 2010

The German Minister for the Environment, Norbert Röttgen (CDU) says the feed-in tariff for solar electricity will be reduced – against the warnings from the industry – by a further 15%.

According to EuPD Research, these cutbacks will lead to a "short-term run" on solar photovoltaic (PV) systems and "falsely push the prices up".

A revision has been going on behind the curtains of the feed-in tariffs for solar electricity as laid out in the Renewable Energy Act (EEG) for a few days now.

Although the solar feed-in tariffs were adjusted in the consumers' favour to the current market conditions just a few days ago, Röttgen is presently outlining the further cuts to solar support.

EuPD Research says the cuts to the solar feed-in tariff are as follows:

As of 1 July, the feed-in tariffs for solar electricity for open-space systems will be reduced by a further 15%. Taking into account the cuts that were already made at the beginning of January, large-scale systems will be taking a 26% cut in promotional funding overall;

As of 1 April, the feed-in tariffs for solar electricity for rooftop systems will be reduced by a further 15%. Taking into account the cuts that were already made at the beginning of January, rooftop systems will be facing a 24% cutback altogether; and

Additionally, there will be a growth corridor for 2011. If the newly-installed solar power capacity in 2010 is more than 3.5 GW, there will be a further 2.5% reduction along with the reduction that is already planned. If more than 4.5 GW is installed, the planned reduction will increase by a further 5%.

Increasing the pressure on the German PV industry

“The PV industry has never before experienced such massive cutbacks. This is naturally increasing the pressure on the German PV industry due to the tightened cost situation,” says Markus A.W. Hoehner, CEO of the market research and consulting institute EuPD Research, on the current developments in Berlin.

“It is to be expected that there will be a very short-term run on PV systems, which will significantly decrease when the tariffs are reduced on the day which has just been announced,” Hoehner adds.

“Hardly any manufacturer can overcome cuts of this kind. The European manufacturers of quality systems and German tradesmen will be particularly badly affected.”

Comparisons with the fated Spanish solar PV market are raising their heads. While the solar PV industry in Spain grew enormously in 2008, the market collapsed completely last year. The reason was the excessive cuts in solar funding and feed-in tariffs.

EuPD Research predicts that in the medium-term, the solar PV sales markets will increasingly move to other regions. The effect that the changes will have on Germany as a location for industry cannot be fully grasped at this point.

“Emigration of leading technology companies, bankruptcies, collapse in sales for tradesmen and a weakened location for the solar industry – these are all realistic scenarios,” Hoehner concludes.

This article is featured in:
Photovoltaics (PV) • Policy, investment and markets • Solar electricity

10 Years in the Sun: The Most Profitable Decade in PV History Draws to a Close

It has been a rollercoaster ride for PV since 2000. Here are the highs and lows and an analysis of where the sector stands as it enters a new decade of opportunities and challenges.

by Paula Mints, Navigant Consulting

Published: 05 March 2010

London, UK [Renewable Energy World Magazine] The year 2000 began with Germany passing its renewable energy law, which established the first feed-in tariff and set the stage for the most profitable and highest growth decade in the 35 year history of the terrestrial solar industry. At the end of 2009, a cumulative 20.6 GW had been sold into the market – 95% of this, or 19.6 GW, in the last 10 years, mostly into grid-connected application.

Between 2000 and 2009, shipments to the first point of sale in the photovoltaic industry grew by a compound annual rate of 39%, and from 2004 to 2008 (boom years for PV), shipments grew by a compound annual rate of 51%. The last decade moved fast, took the industry to new heights and was a rocky, wild ride. It was a ride, however, that moved the industry to a new stage of growth and global acceptance as an energy source.

2009: The Year Pricing Became an Extreme Sport

For a while – four years as a matter of fact – cell and module prices went up, up, up, as the industry continued to promise that grid parity was just on the horizon. Then the industry slammed into 2009's soft demand and prices went down, down, down, taking margins along with them. For most of the year the industry searched frantically for a new market to take the place of Spain, and for financing when a new market was found. The global recession took a heap of blame for a hard 2009, but it was only part of the problem (though, certainly not a trivial one). Manufacturers idled capacity in order to stop adding to already significant inventory. On the good news front, silicon feedstock was plentiful.

The PV industry struggled through over 30 unprofitable years until incentives in Japan, but primarily Europe, gave the industry a market. Germany's innovative feed-in tariff model proved to be the most successful tool for stimulating the market for solar products for one very good reason: it provided an economic motive for installing a photovoltaic system. The feed-in tariff model provided a 20-year annuity for individuals buying systems, and soon caught the interest of investor groups. They realized that, along with a low cost of hardware and given typically high cost of retail electricity in Europe, multi-megawatt systems could provide many years of reliable returns for investors.

This did not happen overnight, but by 2004 demand for solar systems, both residential and commercial, and finally multi-megawatt fields, boomed leading to the first profitable period for manufacturers of solar technology ever. Unfortunately, strong demand for photovoltaic systems coincided with a significant constraint of silicon feedstock, and feedstock pricing pain for manufacturers of crystalline technology. The price of silicon feedstock reached $450/kg at one point during the boom, with manufacturers willing to pay to stay in the game. Meanwhile, a door opened for thin-film manufacturers. During the 2004–2008 boom, thin-film's share of total shipments increased from 5% in 2004 to 14% in 2008, and will be approximately 25% in 2009.

Buying cells and modules during the 2004–2008 period was a wild ride, with strong demand driving prices up as much as 30% in some cases for all technologies. Meanwhile, other countries in Europe instituted feed-in tariffs and demand began to spread out from Germany, particularly to Spain. In 2007–2008, Spain's generous feed-in tariff led to an oversold market in that country along with market conditions that were (in some cases) scandalous. The overselling of its market and the long term commitment implied by the 20-year tariff, led the government of Spain to cap its market, which essentially shut down an industry profit machine that consumed 41% of all PV sales in 2008. Aside from the dangers of overselling a market there is another lesson here – incentives are expensive to support and someone has to pay the bill.

With the market in Spain drying up along with the debt markets and the availability of financing, 2009 started out with over 2 GW of inventory, some on the supply side, but most on the demand side. Yet, at the beginning of the year prices were still high. At the beginning of 2009 there were few technology and system sales while manufacturers tried to hold on to their margins in the midst of soft demand. Figure 1 (page 43, upper) offers a picture of pricing from 2000 through 2009, with an estimate for 2010. Strong demand is expected to return in late 2010 (if Germany does not accelerate the decline in its tariff) and with stronger demand, prices will rise. What goes up must go down and, eventually, up again.

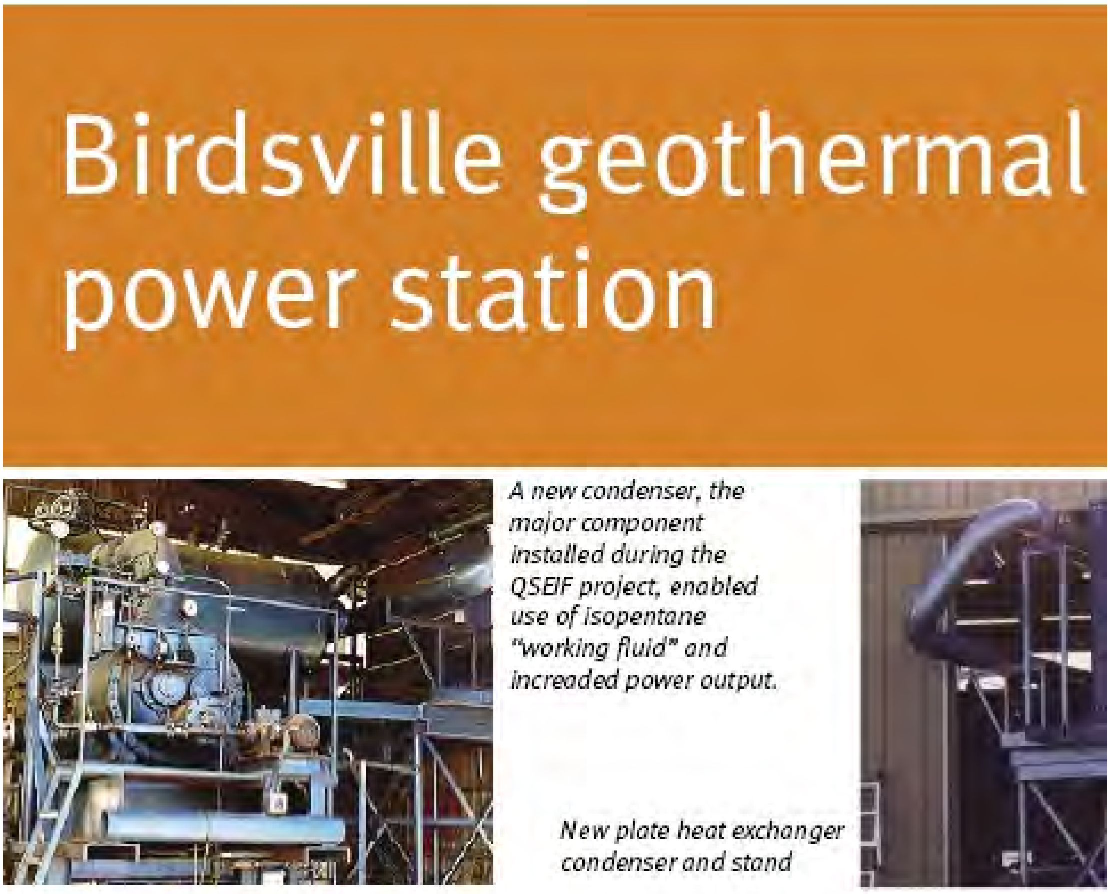
Appendix 6 Birdsville Geothermal

Reports

By Region,Australia & Oceania, By Region, Projects - June 19, 2009

Australia's Birdsville geothermal power station will see upgrade

written by: lxrichter



The government of Queensland in Australia, is investing up to AU$ 4.3 million (US$ 3.4 million) to the upgrade of the Birdsville Geothermal Power Plant. It is a low-temperature plant and currently the country's only operating geothermal plant.

Reported locally, the government of Queensland in Australia, is investing up to AU$ 4.3 million (US$ 3.4 million) to the upgrade of the country's only operating geothermal plant (as there are so far no news on when the pilot plant of Geodynamics will operate again)."

The Birdsville Geothermal Plant is one of very few low-temperature plants with its well tapping into the 98C hot water of the Great Artesian Basin, and being 1230 metres deep. The plant can generate a modest 120 kW net power output.

The investment is “to help replace ageing equipment at the Ergon Energy-owned and operated plant. The funding will provide a 50 per cent subsidy for the project which will invest in new, leading edge geothermal technology.

“The plant draws its energy from near-boiling water taken deep from within the Great Artesian Basin that supplies water for the town. “The power station currently generates about 30 per cent of Birdsville’s energy supplies.

“It’s also helping the local environment by reducing greenhouse gas emissions by about 400 tonnes a year and diesel fuel consumption by approximately 160,000 litres.” Member for Mount Isa Betty Kiernan said the plant upgrade would significantly increase the station’s electricity generating potential.

“The Birdsville geothermal plant was coming to the end of its operational life and the options were simple – upgrade or walk away.

“At any given moment the present plant produces 80 kilowatts of geothermal power. Depending on what geothermal technology is selected, the upgrade could increase the output from a minimum of 90 kilowatts up to 340 kilowatts,”

“This would provide at least 724,000 kWh (kilowatt hours) of clean renewable energy a year compared to the 522,600 KWh produced in 2007.

“The new power station could also save up to 1,575 tonnes of greenhouse gas emissions per year and reduce fuel consumption by at least 181,000 litres per year.

“Ergon Energy is also examining options to see whether the power station can one day supply all of Birdsville’s power from geothermal energy. “

The government is providing up to AU$4.3 million for the project with a grant from the Queensland Renewable Energy Fund.

The balance of the project cost will be met by Queensland Government-owned energy corporation, Ergon Energy.

The Birdsville power station was first commissioned in 1992 and remains Australia’s only operational geothermal power station capable of electricity generation 24 hours a day.

The energy source comes from hot water taken from the Great Artesian Basin at a depth of 1,280 metres. This hot bore water provides a ‘free’ energy resource, which would otherwise be wasted when water is cooled before use.

Queensland Government Procurement office

Display 20090455T

For more detailed information on a particular section refer to the help specific to that section.

Detailed Help *(Clicking detailed help will open a new browser window)*

EXPRESSION OF INTEREST FOR THE DESIGN, CONSTRUCTION AND COMMISSION OF A NEW GEOTHERMAL PLANT AT BIRDSVILLE

Issued by Ergon Energy Corporation Limited

Invitation to Offer

Status:	Closed
Number:	20090455T
UNSPSC:	Building and Construction and Maintenance Services - (100%)
Region/s:	Cairns & Far North Queensland Mount Isa & North West Region The Central West South West & Darling Downs Townsville Mackay Whitsunday Region Rockhampton Gladstone Wide Bay Burnett South East Queensland

Enquiries

Other Contacts

	Naomi Dawson
Type	Contractual
	PHONE: (07) 40804765
	FAX: (07) 40804703
	naomi.dawson@ergon.com.au

Description

Ergon Energy is calling for Expressions of Interest (EOI) for Stage One only from suitably qualified Applicants for the Design, Construction and Commissioning of a new Low Temperature Geothermal Power Station at Birdsville, Queensland.
Ergon Energy will look favorably on Applicants who will work collaboratively with other organisations to provide the best solution. It is expected that the Applicant will partner with Ergon Energy throughout the life of the project.
Ergon Energy is seeking Applicants to confirm their capacity and ability to provide Design, Construction and Commissioning expertise for a Low Temperature Geothermal Power Station in accordance with both options:

• Option 1 – Design, construction and commissioning of a new Geothermal Power Station on the existing site, using the water flow of only 27 litres/sec – maximum. [Note: It is expected that the New Geothermal Plant's energy output is greater than the existing generation of 120kW gross (80kW net) and reduces the (40kW) parasitic load to a lower percentage of the gross generation.]

• Option 2 –. Design, construction and commissioning of a new Geothermal Power Station on the existing site, using the water flow between 27 and 42 litres/sec – maximum. This will be dependent on water licence and the possibility of re-injection of water into the aquifer. [Note: If Ergon Energy is able to secure a water flow resource of 42 litres/sec it is hoped that energy provided by the New Geothermal plant will approach 400kW output with minimal percentage parasitic load.

In responding to the EOI, Applicants must take into consideration the following requirements, restrictions and issues:

(a) Ergon Energy will own and operate the new Geothermal Power Station at Birdsville in its entirety;
(b) The water temperature in the area is approximately 98oC;
(c) Ergon Energy is open to hybrid systems to secure greater energy output. For example the boosting of energy output with solar thermal input to raise water temperature during daylight hours.
(d) The percentage contribution of the geothermal energy input will be one of the evaluation parameters.
(e) Applicants will be responsible for the decommissioning and removal of the existing Geothermal Power Station;
(f) The new Geothermal Power Station must be located on the existing Birdsville geothermal power station site;
(g) The water is the drinking water supply for the township of Birdsville, therefore Applicants must not contaminate the bore water by any means; and
(h) The new Geothermal Power Station must:
• be fully automated;
• have the ability to reduce water flow and electricity generation, when electricity demand is low, to a minimum of 10litres/sec required for the Birdsville Town water supply.
• have full SCADA capability; and
• be integrated with Ergon Energy diesel power station which will be the master station.

FOR FURTHER INFORMATION PLEASE CHECK:
http://www.ergon.com.au/tenders_online/tenders.asp

Oil Drum Report included in CD
Birdsville Brochure included on CD

Appendix 7 Windorah Solar Thermal Plant

Brochure included in CD
Site Photos included in CD
EcoGeneration January / February 2010 Windorah Site Specs

State: Queensland

Owner, developer and operator: Ergon Energy

Capacity: 130 kW nominal

Town: Windorah, approximately 1,200 km west of Brisbane

Demographic: Rural

Commissioned: October 2009

Capital cost: $4.5 million

Construction contractor: Solar Systems

Fuel source: Five concentrated solar photovoltaic dishes

Prime Mover: Solar Systems CS500

Technical Details: The mirrored dishes measure 13.7 metres across. Each dish is supported on a concrete base and steel mast structure, with a total height of 14.5 metres.

Further information:
Bashir Gabriel
Company: Ergon Energy
Tel: 07 4080 4846
Email: bashir.gabriel@ergon.com.au

Do the Bright Thing Web-site
Home > Bright Projects > Windorah Solar Farm

Windorah - Queensland's first solar farm

Queensland's first 150 kilowatt solar farm was officially opened at the remote south-west Queensland town of Windorah in October 2009. The solar farm aims to reduce the town's reliance on diesel fuel, and therefore cut greenhouse gas emissions by approximately 300 tonnes a year.

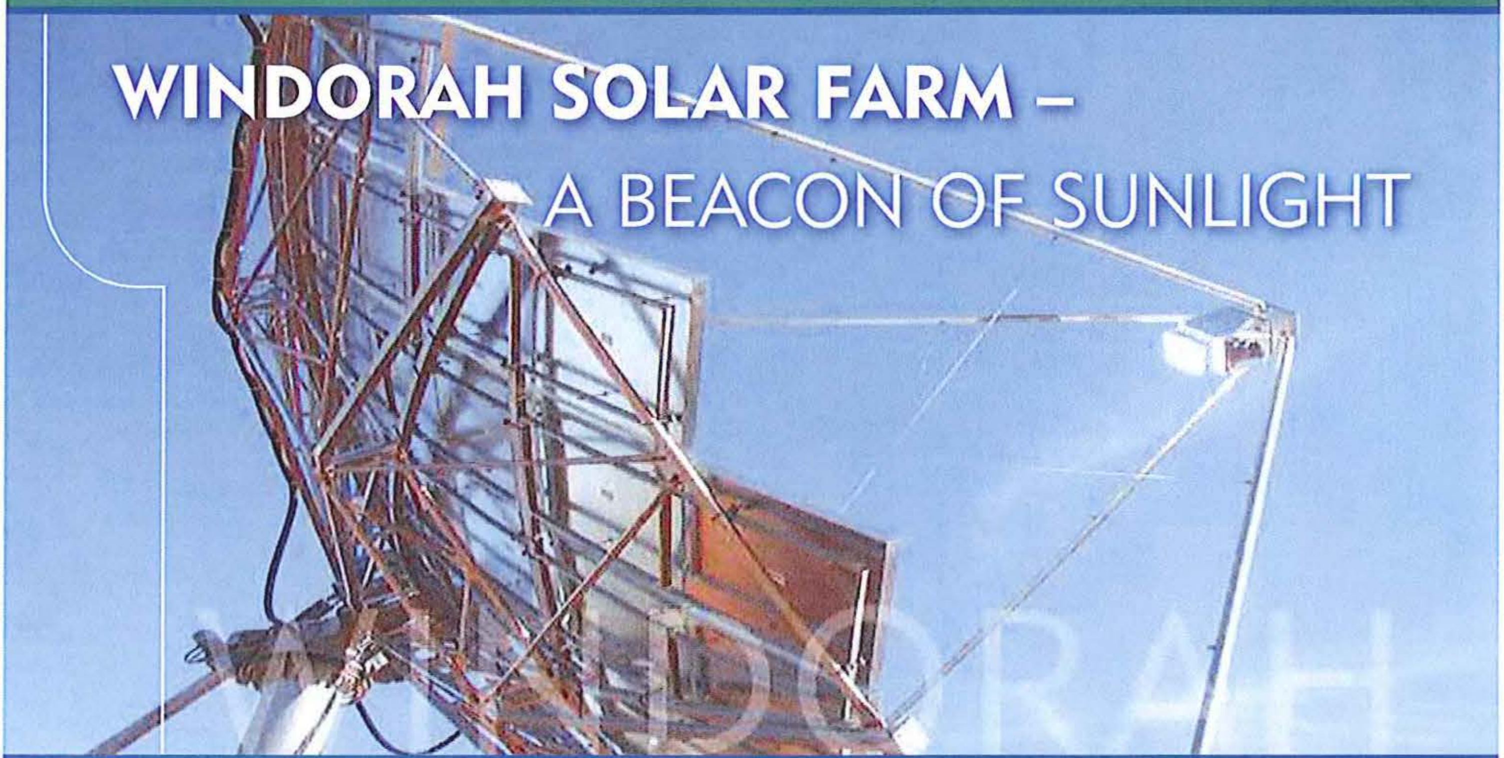
Do the bright thing - help build a 500 megawatt virtual solar power station for Queensland

Town by town, we're working together to double Queensland's solar energy over the next five years. Bright ideas, like the Windorah Solar Farm, are helping to build a 500 megawatt virtual solar power station for Queensland. You can contribute to this target too by doing the bright thing and installing a solar hot water system or solar PV system on your home.

How does the solar farm work?

The $4.5 million solar farm generates electricity using five giant mirrored dishes to capture sunlight and convert the sun's free energy to electricity. The dishes, which

WINDORAH SOLAR FARM – A BEACON OF SUNLIGHT



Windorah has been chosen by Ergon Energy as the site for an innovative solar energy trial using new technology.

- Work began in September 2007 on the construction of a solar farm on the outskirts of the tiny outback Queensland town, population 100. When completed, the facility will be capable of powering the entire town during sunshine hours - a first for Australia.
- The Windorah solar farm will consist of five mirrored dishes 13.7 metres across, each supported on a concrete base and steel mast structure with a total height of 14.5 metres.
- The mirrors reflect and concentrate sunlight on to high-capacity solar cells in a central point at the front of the mirror. Each dish generates approximately 35kW of electricity, depending on season, time of day and cloud cover.
- The solar farm is expected to generate about 360,000 kilowatt hours (kWh) each year.
- This will save approximately 100,000 litres of diesel fuel which would otherwise have been used in the town's diesel generators.
- The solar farm's uniqueness will make it a magnet for visitors and alternative energy enthusiasts.

The benefits

- *The solar farm will be visually impressive and create a unique Windorah landmark.*
- *It will promote and advance solar technology, and Windorah will be seen as a world leader in solar power and sustainable energy generation.*
- *The solar equipment is silent, so when it is operating at full capacity there will be no noise from the power station.*
- *It will reduce the town's reliance on expensive diesel generation, resulting in lower operating costs and reduced greenhouse gas emissions. The reduced power station operating hours will also give the generators a longer life.*
- *The solar farm won't mean downgrading the town's electricity supply system. The diesel generators will remain fully functional and capable of meeting the town's full electricity needs, as they will be in use every night and on cloudy days when the dishes aren't generating. However turning them off for several hours every day will definitely increase their life.*

For information about the project contact:

Mr Bashir Gabriel
Ergon Energy, Cairns.
Ph: (07) 4080 4846
Email: bashir.gabriel@ergon.com.au

everything in our power

ERGON ENERGY

WINDORAH SOLAR FARM – A BEACON OF SUNLIGHT

How a solar farm works

- The five mirror dishes are located on Ergon Energy land next to the existing power station about one km outside the town on the Diamantina Developmental Rd. They are aligned north-south and separated to avoid them shading each other in the early morning and late afternoon.
- Each dish contains 112 mirrors, each 1100mm x 1100mm.
- Like giant sunflowers, the dishes face and follow the sun so that as much sunlight as possible falls on the mirrors. They face the exact location of sunrise, and begin to produce electricity from first light. At the end of the day, the dishes track back around to the east ready for the next day's operation.
- The mirrors concentrate the sun 500 times onto a panel of high-efficiency, satellite-quality photo-voltaic (PV) cells which convert the sun's energy into electricity and feed it into the town's electricity network.
- While the solar farm is producing power, the town's diesel generators will be switched off or operate at reduced output. At night, or when there is too much cloud for the dishes to generate power, the generators will seamlessly be brought back online to supply the town's full demand.
- The system will also include batteries to cope with brief cloud cover without having to start up the generators.
- Modern controls and communications equipment allow for remote monitoring and control of the entire operation, as well as manual operation on site. The control room will be next to the existing power station enclosure, and the entire facility will be fully fenced.

The technology

- Solar concentrator technology is a new way of generating electricity directly from the sun.
- The PV cells have an efficiency of 35%. This represents world-leading efficiency in production technology, and contrasts with 10-12% operating efficiency from conventional flat-plate PV cells.

Why is Ergon Energy doing a trial?

- The aim is to find a viable alternative to diesel generation for communities remote from the electricity grid.
- Windorah was chosen as the community is the right size for a trial of this kind and it has a relatively new power station with technology that is able to interact with the solar farm.
- The project will take about two years to complete and is expected to be supplying the town with electricity by the end of 2008.
- Solar Systems of Victoria won the contract to build the facility.

A solar farm in South Australia similar to the one being built in Windorah

For information about the project contact:

Mr Bashir Gabriel
Ergon Energy, Cairns.
Ph: (07) 4080 4846
Email: bashir.gabriel@ergon.com.au

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ERGON. ENERGY


WINDORAH SOLAR FARM
HOW A SOLAR FARM WORKS
Inverter to AC Power
DC Power
AC Power
Distribution Network
AC Load
Power Station
The five mirror dishes are located on Ergon Energy land next to the diesel power station. They are aligned north-south and separated to avoid them shading each other in the early morning and late afternoon.
Each dish contains 112 mirrors; each mirror is 1100mm x 1100mm.
Like giant sunflowers, the dishes face and follow the sun so that as much sunlight as possible falls on the mirrors. They face the exact location of sunrise, and begin to produce electricity from first light. At the end of the day, the dishes track back around to the east ready for the next day's operation.
The mirrors concentrate the sunlight 500 times onto a panel of high-efficiency, satellite-quality photovoltaic (PV) cells which convert the sun's energy into electricity and feed it into the town's electricity network.
While the solar farm is producing power, the town's diesel generators will operate at reduced output. At night, or when there is too much cloud for the dishes to generate power, the generators will seamlessly be brought back to sufficient capacity to supply the town's needs.
The system also includes batteries to cope with brief cloud cover without having to increase the diesel generators' output.
Modern controls and communications equipment allow for remote monitoring and control of the entire operation, as well as manual operation on site.
THE TECHNOLOGY
The solar concentrator technology used in the farm is a new way of generating electricity directly from the sun.
The PV cells are 35 per cent efficient. That means they convert 35 per cent of the sunlight falling on them into electricity. This represents world-leading efficiency in production technology, and contrasts with 10-12 per cent operating efficiency from conventional flat-plate PV cells.
The solar dishes operate any time the sun is not obscured by cloud with the highest output in the middle of the day.
THE BENEFITS
The solar farm will promote and advance solar technology for the benefit of all, and Windorah will be seen as a model of solar power and sustainable energy generation.
It will reduce the town's reliance on expensive diesel generation, resulting in lower operating costs and reduced greenhouse gas emissions. The reduced power station operating hours will also give the diesel generators a longer life although they will still be capable of meeting the town's full electricity needs as required.
The solar farm is visually impressive and creates a unique Windorah landmark.
TECHNICAL SPECIFICATIONS
Structure height
Structure width
Each dish has:
a concrete support base
a steel frame to support the mirrors and receiver
control and tracking system
Typical peak production
Expected quantity of electricity produced
Expected diesel reduction
Voltage at Maximum Power Point (MPP)
Current at Maximum Power Point (MPP)
Electrical Output
everything in our power
ERGON ENERGY

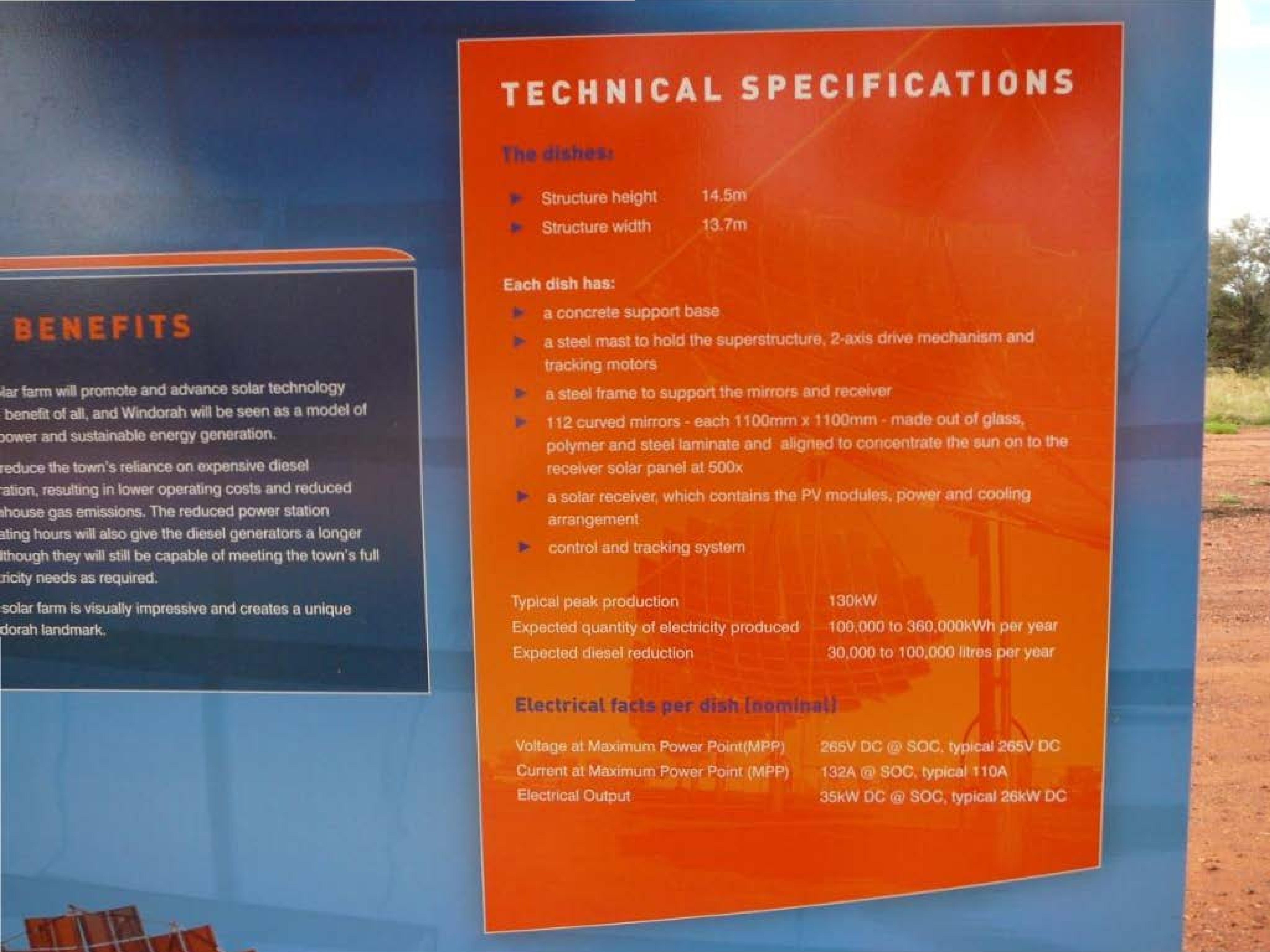
WINDORAH
HOW A SOLAR FARM WORKS
Distribution Network
AC Load
Inverter to AC Power
DC Power
AC Power
Power Station
The five mirror dishes are located on Ergon Energy land next to the diesel power station. They are aligned north-south and separated to avoid them shading each other in the early morning and late afternoon.
Each dish contains 112 mirrors; each mirror is 1100mm x 1100mm
Like giant sunflowers, the dishes face and follow the sun so that as much sunlight as possible falls on the mirrors. They face the exact location of sunrise, and begin to produce electricity from first light. At the end of the day, the dishes track back around to the east ready for the next day's operation.
The mirrors concentrate the sunlight 500 times onto a panel of high-efficiency, satellite-quality photovoltaic (PV) cells which convert the sun's energy into electricity and feed it into the town's electricity network.
While the solar farm is producing power, the town's diesel generators will operate at reduced output. At night, or when there is too much cloud for the dishes to generate power, the generators will seamlessly be brought back to sufficient capacity to supply the town's needs.
The system also includes batteries to cope with brief cloud cover without having to increase the diesel generators' output.
Modern controls and communications equipment allow for remote monitoring and control of the entire operation, as well as manual operation on site.

THE TECHNOLOGY

- The solar concentrator technology used in the farm is a new way of generating electricity directly from the sun.
- The PV cells are 35 per cent efficient. That means they convert 35 per cent of the sunlight falling on them into electricity. This represents world-leading efficiency in production technology, and contrasts with 10-12 per cent operating efficiency from conventional flat-plate PV cells.
- The solar dishes operate any time the sun is not obscured by cloud with the highest output in the middle of the day.

THE BENEFITS

- The solar farm will promote and advance solar technology for the benefit of all, and Windorah will be seen as a model of solar power and sustainable energy generation.
- It will reduce the town's reliance on expensive diesel generation, resulting in lower operating costs and reduced greenhouse gas emissions. The reduced power station operating hours will also give the diesel generators a longer life although they will still be capable of meeting the town's full electricity needs as required.
- The solar farm is visually impressive and creates a unique Windorah landmark.


BENEFITS
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power and sustainable energy generation.
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house gas emissions. The reduced power station
ating hours will also give the diesel generators a longer
lthough they will still be capable of meeting the town's full
ricity needs as required.
solar farm is visually impressive and creates a unique
dorah landmark.
TECHNICAL SPECIFICATIONS
The dishes:
Structure height 14.5m
Structure width 13.7m
Each dish has:
a concrete support base
a steel mast to hold the superstructure, 2-axis drive mechanism and tracking motors
a steel frame to support the mirrors and receiver
112 curved mirrors - each 1100mm x 1100mm - made out of glass, polymer and steel laminate and aligned to concentrate the sun on to the receiver solar panel at 500x
a solar receiver, which contains the PV modules, power and cooling arrangement
control and tracking system
Typical peak production 130kW
Expected quantity of electricity produced 100,000 to 360,000kWh per year
Expected diesel reduction 30,000 to 100,000 litres per year
Electrical facts per dish (nominal)
Voltage at Maximum Power Point(MPP) 265V DC @ SOC, typical 265V DC
Current at Maximum Power Point (MPP) 132A @ SOC, typical 110A
Electrical Output 35kW DC @ SOC, typical 26kW DC

each measure approximately 14 metres in diameter, follow the sun as it tracks across the sky from sunrise to sunset.

Each dish contains 112 mirrors, each measuring 1100mm x 1100mm. The mirrors concentrate the sun up to 500 times onto a panel of photovoltaic cells which convert the sun's energy into electricity and feed it into the town's electricity network.

Different combinations of dishes are used at different times, with some being parked and not used while others are generating power. This all depends on the energy needs of the town's 100 residents.

An animation showing how the technology works can be found by following this link: http://www.energyfutures.qld.gov.au/how_does_solar_energy_work_.cfm

Australian technology

The Windorah Solar Farm uses technology developed in Australia. This project is also the first time Ergon Energy has used solar farm power generation combined with a diesel power station.

Reducing the need for diesel generators

The Windorah Solar Farm does the bright thing, using solar energy to reduce the town's use of diesel-powered generators. While the solar farm is producing electricity during the day, the town's diesel generators operate at a lower level. At night or when there is too much cloud cover, the diesel generators seamlessly kick back in to meet the town's energy needs.

How much electricity does it produce?

It is estimated that the solar farm will produce 300 000 kilowatt hours of electricity a year, reducing the town's diesel consumption by more than 100 000 litres annually. This is expected to reduce the town's greenhouse gas emissions by approximately 300 tonnes a year.

How is it funded?

Queensland Government Owned Corporation, Ergon Energy has invested more than $3.5 million towards construction of the solar farm, with $1 million contributed by the Australian Government through its Renewable Remote Power Generation Program.

More information

Think a solar farm is a bright idea?

- Discover more about the Windorah Solar Farm
- Find out about installing solar panels on your home
- Download a printable version of this information (PDF - 218 KB)

Appendix 8 Cloncurry Concentrated Solar Thermal

Cloncurry CSP

Frequently Asked Questions - Cloncurry Solar Power Pilot Project

What does the project involve?

The project will involve the construction of a solar energy generation facility on a 10 hectare piece of land in Cloncurry. The facility will comprise 54 energy storage towers (approx . 17metres high) and an estimated 8000 reflective mirrors that will reflect and concentrate sunlight into blocks containing a graphite thermal storage medium. When required, water is then pumped through these blocks to generate steam which generates electricity via turbines. Heat stored in the graphite produces steam well after the sun goes down, allowing electricity generators to keep running at night.

How does the steam turbine technology work?

The plant will utilise a Once Through Steam Generator (OTSG) to produce superheated steam . This steam will run through a condensing Rankine Cycle steam turbine with an air-cooled condenser. Characteristics of the components are:

- Once Through Steam Generator (OTSG) – doesn't have a boiler drum and consequently doesn't have the blow-down requirements of a normal steam boiler.
- Air-Cooled Condensor – doesn't use evaporation of water for cooling effect, therefore minimising the use of water in the process.
- Turbine – superheated Rankine Cycle steam turbines are robust and well established in the industry.

Will Cloncurry be totally reliant on this solar power?

The project has the capacity to power all of Cloncurry and in the longer term be a source of energy security for the region. It will supply energy at peak times when demand is high and at similar prices to conventional electricity generation. It is 'green' power with reliance on energy sourced from the sun.

Why is this solar technology so different?

The key difference between this new technology and other solar power generation is the ability to store thermal energy at the point of collection and hold it before it is converted into electricity . This means that the storage losses are very low, thus making the system very efficient. The electricity generation system can, if required, run for 24 hours a day and also provide solar power on cloudy days. The solar energy generation facility will comprise a series of solar reflectors called heliostats which track the sun continuously and concentrate the beams of solar energy into a receiver cavity at the base of the storage blocks sitting on the top of small towers, the height of a small rural windmill. The blocks contain heat exchangers through which water is passed to generate steam and electricity using ordinary steam turbine generators. The energy storage system will enable power to be dispatched 24 hours a day if required, compared with conventional solar systems that only generate during sunlight hours.

What are the project benefits?

It has the potential for Cloncurry to be powered by clean energy, significantly reducing greenhouse gas emissions. It will also provide additional security of supply to users.

This project incorporating this new Australian developed technology will receive international attention. There is likely to be significant tourism and marketing opportunities for the region resulting from the innovative nature of this project.

In addition the project will create over 100 jobs during the construction period.

What is the role of Ergon Energy on this project?

Both Ergon Energy and the Department of Mines and Energy have been instrumental in the development of this project. When the plant is operational Ergon Energy will purchase the power generated to supply the Cloncurry community.

How much water is required to operate this technology?

Due to the use of air condensors and Once Through Stream Generators there will be little water loss from the process. All water used is treated and recycled back through the system, with only a small amount of make-up water required per year. There will be rainwater storage tanks on site to capture runoff from main office/control room buildings with a capacity to store up to 200,000 litres. This harvested water will be more than sufficient for make-up water and site maintenance and there should be no need for the use of potable water.

Are there any safety issues associated with the project?

Solar thermal technology is a relatively new, but safe technology. The storage system using graphite contains no toxic or hazardous materials and produces no emissions or wastes.

Will the project definitely go ahead?

The project is initially subject to feasibility testing on the first full scale module which has recently been constructed in Cooma NSW. This test module is the first of the production modules, and is the result of some six years of developmental work on the components of the system. The testing is being independently undertaken by SMEC Australia, to ensure that the technology will be appropriate to meet the energy needs of the Cloncurry community. Once the testing has been completed,, a range of legislative approvals such as planning, environmental and building will be required to construct the facility.

Who is Lloyd Energy and what is their background?

Lloyd Energy Systems, is an Australian owned and controlled company .

Lloyd Energy Systems was formed to further develop and commercialise the Energy Storage technology established by the renowned Australian scientist Robert Lloyd. Designed around the unique properties of high purity graphite, Lloyd Energy is developing an energy storage systems for Clients nationally and internationally.

What is the timing for completion of the project?

It is anticipated the generation facility will be commissioned in September 2009.

How will the community be kept informed and provided with an opportunity to have input?

More detailed information on the project will be provided to interested persons and the local community through media, including local and national newspapers. It is also envisaged that, community information session/project displays and ongoing community newsletters will be provided throughout the duration of the project. Regular updates will be provided on the Lloyd Energy Website www.lloydenergy.com.

How can I find out more about this project?

Contact: Project Stakeholder Manager – Libby Paholski

Phone: 1800 601 858

North West Star News Skip directly to: Search Box, Section Navigation, Content.

News
Local News
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General
Powerless - Curry still waiting for solar plant

Powerless - Curry still waiting for solar plant

STEVEN SCHUBERT
19 May, 2010 08:15 AM

IT WAS supposed to be a revolutionary renewable energy project for the hottest part of Australia, but the solar power plant project in Cloncurry has gone cold.

The solar power plant was scheduled to be up and running by the end of last year but not even a small-scale demonstration plant has been completed.

Cloncurry Shire Council Mayor Andrew Daniels said the community was frustrated by the delays and was uncertain if the project would ever be finished.

"The community want to know what's going on with it. It's very frustrating," he said.

Cr Daniels said he was not sure if the company that was supposed to be building the solar plant, Lloyd Energy Systems, was still in business.

Lloyd Energy Systems was not answering its listed phone number yesterday, and its website had been taken down.

The biggest problem for Cloncurry is the half-built demonstration plant in Mary Kathleen Park.

The demonstration plant consists of a large tower surrounded by mirrors and was supposed to power the tourist centre at the park and show the public how the technology worked.

"We wanted to put in the demonstration plant to promote the solar project," Cr Daniels said.

"Back in February when I rang Lloyd Energy Systems they said they would see how they were going and we might see the demonstration plant finished in six or seven months. But I haven't heard anything from them since."

The people of Cloncurry want answers as to why they have a white-elephant sitting in the middle of their tourist park.

"The worst thing about it is that every time I drive home it's there to remind me of it," Cr Daniels said.

The State Government gave $7million to the $30million project and Premier Anna Bligh praised the project when it was announced three years ago.

"It's a real breakthrough for electricity generation. We're creating continuous 24-hour electricity for Cloncurry," she said in 2007.

The Premier yesterday did not return requests for an explanation as to why the project had stalled.

Cr Daniels said the community needed to know what was happening with the solar plant.

"Why would the government put $7million into something they're not certain would work? These are the questions that need to be asked and these are the questions that need to be answered," he said.

The full-scale solar power plant near Cloncurry Airport was supposed to have between 50 and 100 towers. Each tower would have been surrounded by mirrors which reflected sunlight to heat a block of pure granite.

The granite would heat water into steam to drive a turbine to generate electricity.

The plant was supposed to have been able to generate 10 megawatts of electricity each day, while Cloncurry needed only eight megawatts.

The surplus electricity would have been put back into the grid.

MARTIN RASINI

May 22nd, 2010

THE Queensland Government has moved to assure residents of Cloncurry that a new-age technology project designed to provide the north-west Queensland town with renewable energy is not a white elephant.

Cloncurry residents have been concerned about the slow progress of the project and wondering whether the $30 million full-scale plant will materialise.

The $30 million project, first announced in 2007, is the beneficiary of a $7 million State Government grant, but has been slow in coming.

Construction did not begin until the third quarter of 2009 of a small-scale pilot plant, which now sits unfinished in the town's Mary Kathleen Park.

Cloncurry Shire Council Mayor Andrew Daniels has been quoted in media reports this week as saying the community was frustrated by the delays and uncertain if the project would ever be finished.

"The community wants to know what is going on with the project. It is very frustrating." he said.

Yesterday Natural Resources, Mines and Energy Minister Stephen Robertson said the government remained 100 per cent committed to the Cloncurry pilot plant, which would trial new technology.

The solar energy plant is to be built by Sydney company Lloyd Energy Systems and utilises a technology based on the heat-storage properties of graphite.

Mirrors track the sun's passage and feed its energy into a block of graphite, which stores the heat until it is retrieved in the form of electricity.

This is done by passing water through heat exchangers embedded in the graphite block, creating steam that drives a turbine.

Lloyd Energy Systems declined to comment on the project yesterday other than to say it intended to complete the pilot plant, built to provide power for a tourist centre at Mary Kathleen Park, by the end of September.

The pilot plant features a single block of graphite, while the full-scale plant is designed to provide power for the whole Cloncurry community and will have from 50 to 100 graphite blocks surrounded by mirrors.

Mr Robertson said the Cloncurry project was one of the first of its kind and the Queensland Government saw it "as being fundamentally important to advancing solar power as a genuine, renewable energy source".

"Lloyd Energy Systems is working through trials at its NSW project which will help inform the Cloncurry trial and ultimately produce a better result," he said.

"Ergon Energy is expected to provide the government with a report on the performance of the trial as well as recommendations on the feasibility of expanding the trial into a 10 megawatt project.

"Only after the trial is complete and all information is available can we invest remaining funds and progress to the next stage.

"It would be irresponsible to do otherwise," he said.

"The government wants to get this new technology right so we can best utilise solar energy in Queensland well into the future."

Photos of Lloyd Cooma on CD
Project Presentation on CD

Original announcement

Published: 25 September 2007

$15M grant the hot ticket to pollution-free energy

Image courtesy of Geodynamics Limited

Harnessing an untapped energy source which has the capacity to power Australia for 6000 years will be the focus of a new centre at The University of Queensland (UQ).

Queensland Premier Anna Bligh has announced a $15 million five-year contribution to a new research and development centre for "hot rocks" - the Queensland Geothermal Energy Centre of Excellence.

Welcoming the announcement, UQ Senior Deputy Vice-Chancellor, Professor Paul Greenfield, said it could lead to abundant zero-emission baseload electricity.

"Geothermal energy has unique potential in that it creates no greenhouse gas and could be a reliable source of baseload power, so it will satisfy industry, householders and the growing demand for "green" energy," Professor Greenfield said.

"It will become cost-competitive when the expense of mitigating greenhouse gas emissions from fossil fuels is factored in.

"This energy source is often called "hot rocks" because it is based on fractured granites, heated to up to 250°C, which are at least 3km below the Earth's surface," Professor Greenfield said.

UQ Deputy Vice-Chancellor (Research), Professor David Siddle, said: "The Cooper and Eromanga Basins beneath Queensland and South Australia are believed to be among the best and hottest in the world, and hold enough water to supply the needs of a hot rocks power plant, without depleting the natural aquifer."

Queensland's geothermal energy resource is equivalent to that needed to supply Australia's current demands for 6000 years.

"In the shorter term, we estimate that 4000MW of geothermal power could be generated by 2030 without any carbon dioxide emissions," Professor Siddle said.

There would be three main steps to the process:
• Water would be forced downwards through natural rock fractures, where it would be heated and then rise through other fractures to above-ground heat exchangers;
• The heat exchangers would heat a working fluid to drive a turbine-generator set, to produce electricity with no greenhouse emissions;
• Meanwhile, the water which had been thrust to the surface by the hot rocks would be recycled back into the earth to be reheated, forming a closed water circuit.

Professor Greenfield said that the centre of excellence was an investment in research and development, as well as in the expansion of technical expertise.

"We need these investments to make large-scale geothermal power generation a sustainable reality," he said.

"Ideally geothermal should become part of a mix of energy sources which would include clean coal and gas, and established renewables."

In addition to the $15 million from the Queensland Government, UQ will provide in-kind contributions valued at $3.28 million over five years and a further $2.05 million will be raised from external sponsors.

The centre will be the biggest of its type in the nation and will make Queensland and Australia a leading technology provider in the growing geothermal energy sector, through research and development. UQ will work with institutions in the USA – where Massachusetts Institute of Technology (MIT) will be a partner – and Iceland, as well as relevant Australian collaborators.

Brisbane-based company, Geodynamics Ltd, is one of about 16 companies active in geothermal power generation in Australia. Geodynamics Ltd initiated Australia's first underground heat exchanger in the Cooper Basin in late 2002.

Professor Greenfield said the new centre would not have been possible without expertise provided by UQ researchers including Professor Hal Gurgenci (School of Engineering); Professor Victor Rudolph (School of Engineering); Professor Max Lu (Australian Institute for Bioengineering and Nanotechnology); and Professor Tapan Saha (School of Information Technology and Electrical Engineering).

Media inquiries: Fiona Kennedy (07 3365 1088, 0413 380 012 fiona.kennedy@uq.edu.au).

Queensland Government Announcement
Premier
The Honourable Anna Bligh

Thursday, September 27, 2007

$15M Qld Geothermal Energy Centre a 'nation-leader': Bligh

26 September 2007

THE State Government will establish a nation-leading Centre of Excellence to ensure Queensland is best placed to take advantage of the emerging source of 'hot rocks' or geothermal energy, Premier Anna Bligh said today.

"Geothermal or 'hot rocks' energy has the potential to generate one fifth of Australia's total electricity needs over the next 25 years without producing any carbon dioxide emissions," said Ms Bligh.

Geothermal energy is produced from heat generated and captured from deep inside the earth.

The Premier said that the State Government would provide $15 million over the next five years to establish the Queensland Geothermal Energy Centre of Excellence. The University of Queensland will contribute a further $3.3 million for the centre's establishment.

"This centre will ensure the Smart State leads the nation in developing the skills base and technological know-how to develop large-scale, zero-emission power generation,'' Ms Bligh said.

"The centre will establish a critical mass of scientific and engineering expertise specialising in geothermal power generation which will help make Queensland a hub for developing this exciting new technology.''

Queensland has massive geothermal energy resources in the Cooper and Eromanga basins in the State's South West (see attached map), potentially capable of supplying the entire nation with electricity for the next 6000 years.

"Work by specialist geothermal companies indicates that these resources could generate large amounts of zero emission power.

"However, if the resource is to live up to its potential key challenges remain, such as developing the expertise to reliably drill up to 5km into the earth and transmitting large amounts of power over long distances due to the remoteness of geothermal sites.

"This centre of excellence will put Queensland in the driver's seat regarding the development of relevant research to help address these issues,'' she said.

"It will also allow research collaborations on geothermal energy with leading global institutions, such as Massachusetts Institute of Technology.''

"The University of Queensland will seek to work with the University of Adelaide, the International Energy Agency which runs a cooperative program on geothermal research and technology and other national and overseas institutions with interests in geothermal energy."

The Government's $15 million commitment to establish the centre will be funded from the Renewable Energy Fund and the Climate Change Fund established as part of ClimateSmart 2050.

Media contact: Premier's Office 3224 4500

Geothermal Appointments

New Chair announced for UQ Geothermal Energy Centre of Excellence

The chairman for the Queensland Geothermal Energy Centre of Excellence (QGECE) was officially announced today.
The Queensland Government and The University of Queensland (UQ) announced that Professor Trevor Grigg had taken up the position as the Independent Chair of the Board for the sustainable energy research centre.
Minister for Natural Resources, Mines and Energy Stephen Robertson said Professor Grigg brought a wealth of experience to the position and would help build Queensland's smart and green credentials.
"The Queensland Government is committed to a renewable energy future and we see geothermal as a significant component of this goal," he said.
"The State Government provided UQ with $15 million to help establish QGECE and

drive research and development in the geothermal energy sector in Queensland.
"Geothermal is not a new concept, however, Queensland has some unique advantages primarily in the Cooper Basin which has some of the hottest rocks of their type in the world and is a relatively shallow.
"QGECE's focus is in developing technologies that position Queensland to utilise this natural resource.
"Professor Grigg is very well respected and I have full confidence in his ability to continue our push for a sustainable energy future."
The University of Queensland Vice-Chancellor Professor Paul Greenfield said the Government had selected Professor Grigg from a field of very eminent candidates.
"Professor Grigg's expertise in managing industry partnerships brings new strength to the global profile of Queensland geothermal power," Professor Greenfield said.
Professor Grigg, who was formerly Deputy Vice Chancellor (International and Development) at The University of Queensland, is an engineering economist with a strong commercial and infrastructure planning and investment background.
Over the past decade, he has been involved in a number of major international initiatives linking UQ with overseas industry, government and university partners in collaborative development programs.
He has extensive board director experience acquired over 20 years on research and development, commercialisation, telecommunications, public utility and international education companies.
Professor Grigg said he welcomed the opportunity and challenge of the role to help drive the development of a significant geothermal energy industry in Queensland through high level collaboration between the QGECE, the Queensland State Government, industry, and other national and international energy research institutes.
"Working with other experienced board members and with the QGECE Director and his staff who already have international research reputations, I am confident that the QGECE will make a major contribution to geothermal energy development in the State of Queensland," Professor Grigg said.
The research being conducted at the Centre includes new cycles and cycle fluids for higher efficiencies; new cooling tower designs; and new knowledge on the magnitude and the nature of geothermal resources in Queensland.
The Centre has already acquired a global reputation through its pioneering work in supercritical carbon dioxide geothermal siphon.
The Centre held a very successful meeting with its stakeholders earlier this year, where 73 delegates from industry, academia and government from around Australia discussed the Centre's program of activities.
Queensland Geothermal Energy Centre of Excellence (QGECE) Director, Professor Hal Gurgenci said that the QGECE was fortunate to appoint as its Chair someone with Professor Grigg's reputation and experience and that he looked forward to working with him to progress geothermal energy in Queensland.

Minister for Natural Resources, Mines and Energy and Minister for Trade
The Honourable Stephen Robertson
01/06/2010

QGECE Projects

A new project by the Queensland Geothermal Energy Centre of Excellence (QGECE) at The University of Queensland is aiming to identify new resources for enhanced geothermal systems.

UQ researchers are preparing for a significant increase in geothermal exploration activities, also known as hot rock geothermal, following the Geothermal Energy Bill which was tabled in the Queensland Parliament on May 19.

QGECE’s Dr Tonguç Uysal said the pioneering study would attempt to identify Queensland’s hot rock geothermal resources without having to drill deep exploration holes.

“The analysis of near-surface mineral alterations and geochemistry is a well-established method in mineral exploration but it has not been used yet in exploring hot rock geothermal resources,” Dr Uysal said.

“We are one of the few groups in the world working in this area and, in this project, we would like to apply it here in Queensland so that we can better understand and identify Queensland’s hot rock geothermal resources.

“The existence of such knowledge would substantially increase the chances of success in future geothermal projects and would increase the commercial viability of geothermal electricity.”

QGECE PhD student Alex Middleton is investigating the alteration mineralogy of sedimentary rock samples containing the trace element and isotopic signatures of deep high heat-producing granites.

Mr Middleton has said he was planning to analyse samples from the Galilee Basin, Innot Hot Springs region, Hodgkinson Province, Styx Basin, Maryborough Basin and North d’Aguillar Block, Wandilla Province.

“The granites in these areas were generated between the Late Devonian to Triassic representing a geologic time span from 370 to 230 million years ago,” Mr Middleton said.

“Our preliminary research indicates significant promise of hot rock geothermal energy in these areas and my project may provide more evidence for this.”

The Galilee Basin is of special interest to the researchers as it directly overlies the Drummond Basin, which is known to harbour Devonian-Carboniferous granitic igneous rocks abundant in uranium and thorium, providing a significant potential for hot rock geothermal systems. Similar expectations apply to the other target areas.

The Queensland Geothermal Energy Centre of Excellence was established last year at The University of Queensland by a $15 million grant from the Queensland State Government. The QGECE is funded by the Renewable Energy Fund and the Climate Change Fund established as part of Queensland’s ClimateSmart 2050 climate change strategy.

The Queensland Government expects 250 MWe to be generated from geothermal energy in Queensland by 2020.

Appendix 10 Coastal Geothermal Programme

Also included on CD

Department of Employment, Economic Development and Innovation
Geological Survey of Queensland

Coastal Geothermal Energy Initiative

Queensland's known geothermal resources are in the far south-west of the state, a long way from the existing electricity transmission lines and major population centres. The $5 million Coastal Geothermal Energy Initiative (CGEI) is the Queensland Government's program to implement the commitment in the ClimateSmart 2050 strategy through the Queensland Renewable Energy Fund to investigate additional sources of hot rocks for geothermal energy close to existing transmission lines. The CGEI is a cooperative undertaking between Office of Clean Energy and Geological Survey of Queensland.

Timeframe: January 2009–June 2012

Objectives

- Identify areas in eastern Queensland where collecting additional temperature and heat flow data sets is required
- Collect new data by drilling specific wells and through liaison with industry
- Improve geophysical coverage of coastal areas where required
- Provide an enhanced assessment of geothermal resource potential in eastern Queensland.

Rationale

Thirty-eight potential geothermal targets have been identified based upon a current understanding of the geology and tectonic history of eastern Queensland (map over page). These areas are considered to have the potential for hot rocks to be present at depth where elevated heat-flow conditions may exist. Likely presence of deep heat source overlain by thick succession of thermal blanketing sediments and proximity to existing transmission lines are prominent attributes that were considered in identifying each target.

A thorough geo-scientific assessment has been undertaken for each potential geothermal target based on available geological and geophysical data.

Potential targets covered by a granted or application for a Geothermal Exploration Permit were not selected to be tested for drilling under this initiative.

Drilling Program

The drilling program is anticipated to begin in second half of year 2010 and will include:

- Fully cored HQ size boreholes from below unconsolidated formations to nominal depth of 300–320 m
- Temperature and additional petrophysical data from geophysical down-hole logging
- Well log interpretation and core logging
- Collection of core samples for analysis of thermal conductivity property.

Geoscience Australia will provide technical support through laboratory analysis and down-hole logging. Temperature measurements and thermal conductivity measurements will be used to determine conductive heat-flow regime for each borehole. Additional geophysical data may be acquired over target areas as determined from the drilling results.

Outcomes

- Provide an updated database of temperature and heat flow data sets
- Develop maps showing heat anomalies in eastern Queensland
- Report on the geothermal potential of eastern Queensland and
- Provide the background data for industry to identify potential targets for geothermal energy exploration in eastern Queensland.

Further information

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www.deedi.qld.gov.au
www.cleanenergy.qld.gov.au

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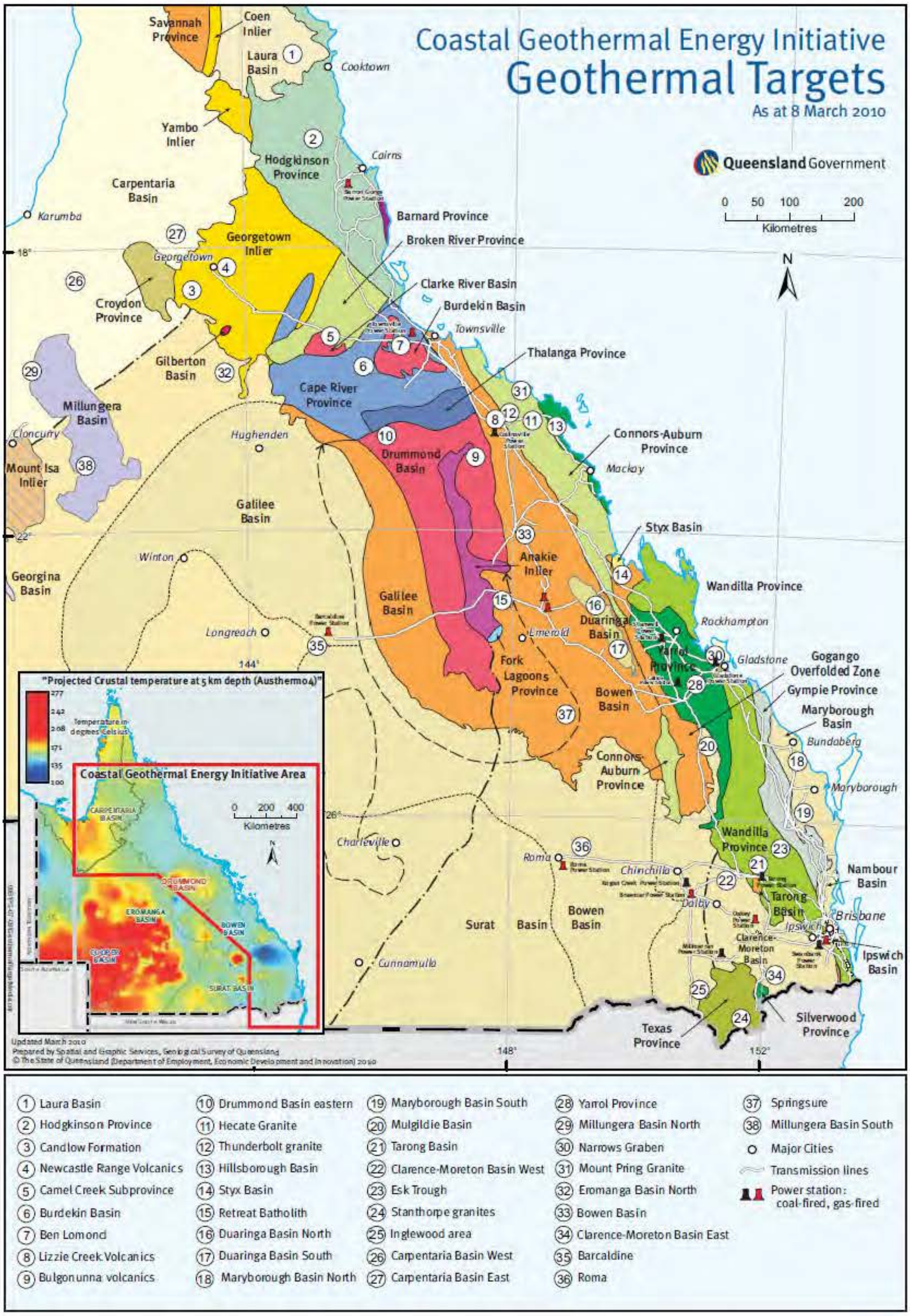

Coastal Geothermal Energy Initiative
Geothermal Targets
As at 8 March 2010
Queensland Government
0 50 100 200
Kilometres
N
Savannah Province
Coen Inlier
Laura Basin
Cooktown
Yambo Inlier
Hodgkinson Province
Cairns
Carpentaria Basin
Karumba
Barnard Province
Broken River Province
Georgetown Inlier
Georgetown
Croydon Province
Clarke River Basin
Burdekin Basin
Townsville
Gilberton Basin
Thalanga Province
Cape River Province
Millungera Basin
Cloncurry
Hughenden
Drummond Basin
Connors-Auburn Province
Mackay
Mount Isa Inlier
Galilee Basin
Styx Basin
Winton
Anakie Inlier
Wandilla Province
Georgina Basin
Galilee Basin
Duaringa Basin
Rockhampton
Longreach
Emerald
Yarrol Province
Gladstone
Gogango Overfolded Zone
Fork Lagoons Province
Bowen Basin
Gympie Province
Maryborough Basin
Bundaberg
Connors-Auburn Province
Maryborough
Wandilla Province
Charleville
Roma
Chinchilla
Nambour Basin
Tarong Basin
Dalby
Brisbane
Surat Basin
Bowen Basin
Clarence-Moreton Basin
Ipswich Basin
Cunnamulla
Texas Province
Silverwood Province
"Projected Crustal temperature at 5 km depth (Austhermo4)"
Temperature in degrees Celsius
Coastal Geothermal Energy Initiative Area
0 200 400
Kilometres
Updated March 2010
1 Laura Basin
2 Hodgkinson Province
3 Candlow Formation
4 Newcastle Range Volcanics
5 Camel Creek Subprovince
6 Burdekin Basin
7 Ben Lomond
8 Lizzie Creek Volcanics
9 Bulgonunna volcanics
10 Drummond Basin eastern
11 Hecate Granite
12 Thunderbolt granite
13 Hillsborough Basin
14 Styx Basin
15 Retreat Batholith
16 Duaringa Basin North
17 Duaringa Basin South
18 Maryborough Basin North
19 Maryborough Basin South
20 Mulgildie Basin
21 Tarong Basin
22 Clarence-Moreton Basin West
23 Esk Trough
24 Stanthorpe granites
25 Inglewood area
26 Carpentaria Basin West
27 Carpentaria Basin East
28 Yarrol Province
29 Millungera Basin North
30 Narrows Graben
31 Mount Pring Granite
32 Eromanga Basin North
33 Bowen Basin
34 Clarence-Moreton Basin East
35 Barcaldine
36 Roma
37 Springsure
38 Millungera Basin South
Major Cities
Transmission lines
Power station: coal-fired, gas-fired

Appendix 11 Queensland Generation Capacity

Non-scheduled Generation Capacity - Queensland

Name	Fuel Type	Owner	MW
Inkerman Mill	Bagasse	CSR	11
Kalamia Sugar Mill	Bagasse	CSR	9
Macknade Mill	Bagasse	CSR	8
Plane Creek Mill	Bagasse	CSR	14
Victoria Mill	Bagasse	CSR	12
Invicta Mill	Bagasse	CSR	39
Pioneer Sugar Mill	Bagasse	CSR	68
Rocky Point Cogeneration Plant	Biomass	Rocky Point Green Power	28
Oaky Creek	Gas (Methane)	Envirogen	15
Wivenhoe Small Hydro	Hydro	Stanwell Corporation	5
Daandine Power Station	Thermal - Landfill Gas	Country Energy	33
Rochedale	Thermal - Landfill Gas	Country Energy	3
Whitwood Road Renewable Energy Facility	Thermal - Landfill Gas	Country Energy	1
Windy Hill	Wind	Transfield Services	12
ISIS Central Sugar Mill	Cogen Gas	AGL Energy	25
Roghan Road	Thermal - Landfill Gas	AGL Energy	2
Moranbah	Thermal - Landfill Gas	AGL Energy	13
Suncoast Gold Macadamias	Biomass	AGL Energy	2
KRC Castlemaine Cogen	Thermal - Landfill Gas	AGL Energy	5
Veolia Ti Tree Bio Reactor	Thermal - Landfill Gas	Veolia Environmental Services	2
Moranbah North Power Station	Gas (Methane)	EDL	46
Browns Plains	Thermal - Landfill Gas	EDL	2
German Creek	Thermal - Landfill Gas	AGL Energy	32
Tarong Gas Turbine	Gas	Tarong Energy	15
Kareeya	Hydro	Stanwell Corporation	7
		Regional subtotal:	**409**

Summer Scheduled Capacity

Summer	**2009 /10**	**2010 /11**	**2011 /12**	**2012 /13**	**2013 /14**	**2014 /15**	**2015 /16**	**2016 /17**	**2017 /18**	**2018 /19**	**Class**
Barcaldine GT	49	49	49	49	49	49	49	49	49	49	S
Barron Gorge Hydro	60	60	60	60	60	60	60	60	60	60	S
Braemar GT	435	435	435	435	435	435	435	435	435	435	S
Braemar 2 [1] GT	462	462	462	462	462	462	462	462	462	462	S
Callide A [2]	0	30	30	30	30	30	0	0	0	0	S
Callide B	700	700	700	700	700	700	700	700	700	700	S
Callide C	900	900	900	900	900	900	900	900	900	900	S
Collinsville	187	187	187	187	187	187	187	187	187	187	S
Condamine[3]	135	135	135	135	135	135	135	135	135	135	S
Darling Downs[4] CCGT	605	605	605	605	605	605	605	605	605	605	S

Gladstone	1680	1680	1680	1680	1680	1680	1680	1680	1680	1680	S
Kareeya Hydro	88	88	88	88	88	88	88	88	88	88	S
Kogan Creek	724	724	724	724	724	724	724	724	724	724	S
MacKay GT	27	27	27	27	27	27	27	27	27	27	S
Millmerran	852	852	852	852	852	852	852	852	852	852	S
MtStuart[5] GT	387	387	387	387	387	387	387	387	387	387	S
Oakey GT	275	275	275	275	274	274	273	273	273	273	S
Roma GT	54	54	54	54	54	54	54	54	54	54	S
Stanwell[6]	1390	1397	1404	1404	1404	1404	1404	1404	1404	1404	S
Swanbank B	480	480	480	480	480	480	480	480	480	480	S
Swanbank E CCGT	350	350	350	350	350	350	350	350	350	350	S
Tarong	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	S
Tarong North	443	443	443	443	443	443	443	443	443	443	S
Townsville CCGT	235	235	235	235	235	235	235	235	235	235	S
Wivenhoe PS	500	500	500	500	500	500	500	500	500	500	S
Yarwun Cogen	0	152	152	152	152	152	152	152	152	152	S
Total	12068	12257	12614	12614	12613	12614	12585	12585	12584	12584	

[1] Unit 1 and 2 are planned for commissioning by May 2009 and Unit 3 by June 2009

[2] This station will be used in an oxy-firing trial

[3] This station is planned for service by summer 2009/10

[4] This station is planned for service by winter 2010

[5] The expanded capacity of this station is planned for service by November 2009

[6] Small capacity variations are due to ambient conditions.

[7] This station is planned for service by May 2010

BIRDSVILLE GEOTHERMAL POWER STATION –

POWER FOR THE FUTURE

The Present

- Birdsville is currently home to the only operating geothermal power station in Australia.
- It uses water from the Great Artesian Basin which is naturally heated by the earth more than one kilometre under the surface.
- The station is also one of the few low-temperature geothermal stations in the world.
- It provides 80kW of electricity – approximately 25 per cent of Birdsville township's power. The rest is provided by one 300 kW LPG-fired and two 300kW diesel-fired generators.
- The existing system draws water at 98 degrees C up a 1.2 km deep bore from an artesian aquifer. The water is run through a gas-filled heat exchanger which heats and pressurises the gas which drives a turbine and alternator to produce electricity.
- The partly-cooled water is channelled into a pond for further cooling and reticulation into the town's water supply and the lagoon on the opposite side of the town.

The Possibilities

- Geothermal energy is considered to be one of the most exciting potential new sources of energy for Australia
- Ergon Energy is keen to determine whether the artesian aquifer underneath Birdsville has the capacity to meet all of Birdsville's energy requirements and at the same time reduce the net volume of water taken from the aquifer.

The Feasibility Study

- Ergon Energy will investigate the potential of the artesian aquifer to supply more heat energy in order to generate more electricity.
- The goal is to supply all of Birdsville's day-to-day electricity needs from geothermal energy, with the gas and diesel generators maintained for use as back-up when required.
- A feasibility study is being undertaken to find out:
  - Community expectations and needs
  - Bore location and depth
  - Potential artesian water flow rate
  - Water temperature
  - Electricity generating potential
  - Potential impacts on the artesian basin
  - Optimum geothermal power station technology

Birdsville: one of the most isolated spots in Australia

For information about the project contact:

Mr Bashir Gabriel
Ergon Energy, Cairns.
Ph: (07) 4080 4846
Email: bashir.gabriel@ergon.com.au

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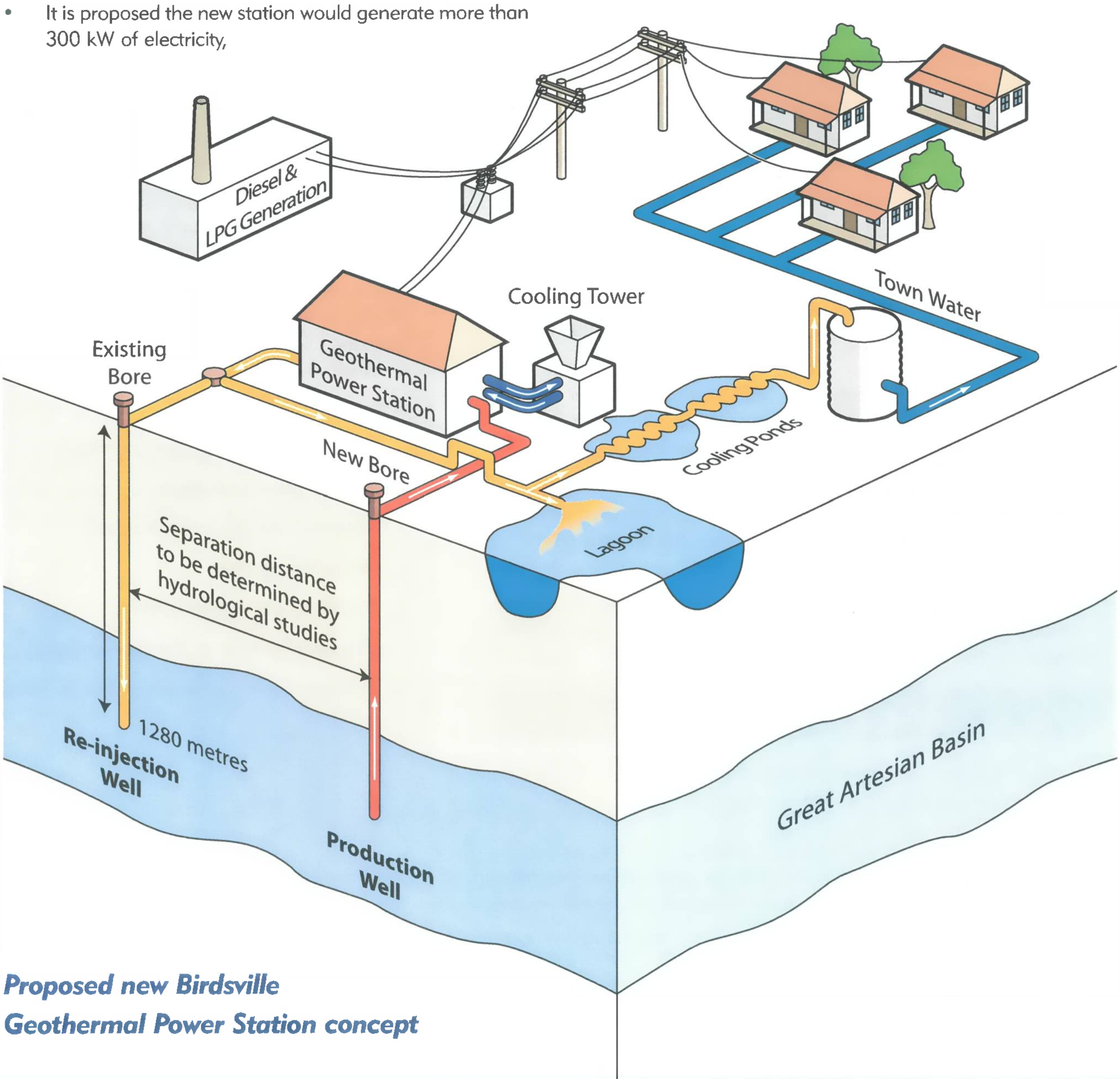
BIRDSVILLE GEOTHERMAL POWER STATION
– POWER FOR THE FUTURE

Possible New Geothermal Power Station

If the underground hot water resource is found to be adequate, Ergon Energy proposes to build a new, larger geothermal power station at Birdsville.

- It would use a new, higher-capacity bore to draw water to the surface for generating electricity. After the heat is extracted for power generation, the water would continue to supply the town and the lagoon, and the remainder would be used to replenish the aquifer by reinjecting it into the existing bore.
- It is proposed the new station would generate more than 300 kW of electricity,
- It would use new technology to efficiently generate more electricity per unit of heat out of the water
- It would also be a more sustainable use of the artesian resource, as the majority of water passing through the power station would be pumped back into the aquifer, recharging it for future use.



Proposed new Birdsville Geothermal Power Station concept

For information about the project contact:

Mr Bashir Gabriel
Ergon Energy, Cairns.
Ph: (07) 4080 4846
Email: bashir.gabriel@ergon.com.au

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ERGON ENERGY


#13


LLOYD ENERGY

CLONCURRY
SOLAR THERMAL STORAGE PROJECT



SMEC Group of Companies

Lloyd energy storage

The Project

will

Demonstrate solar energy “on-demand” through Lloyd’s solar storage system

to

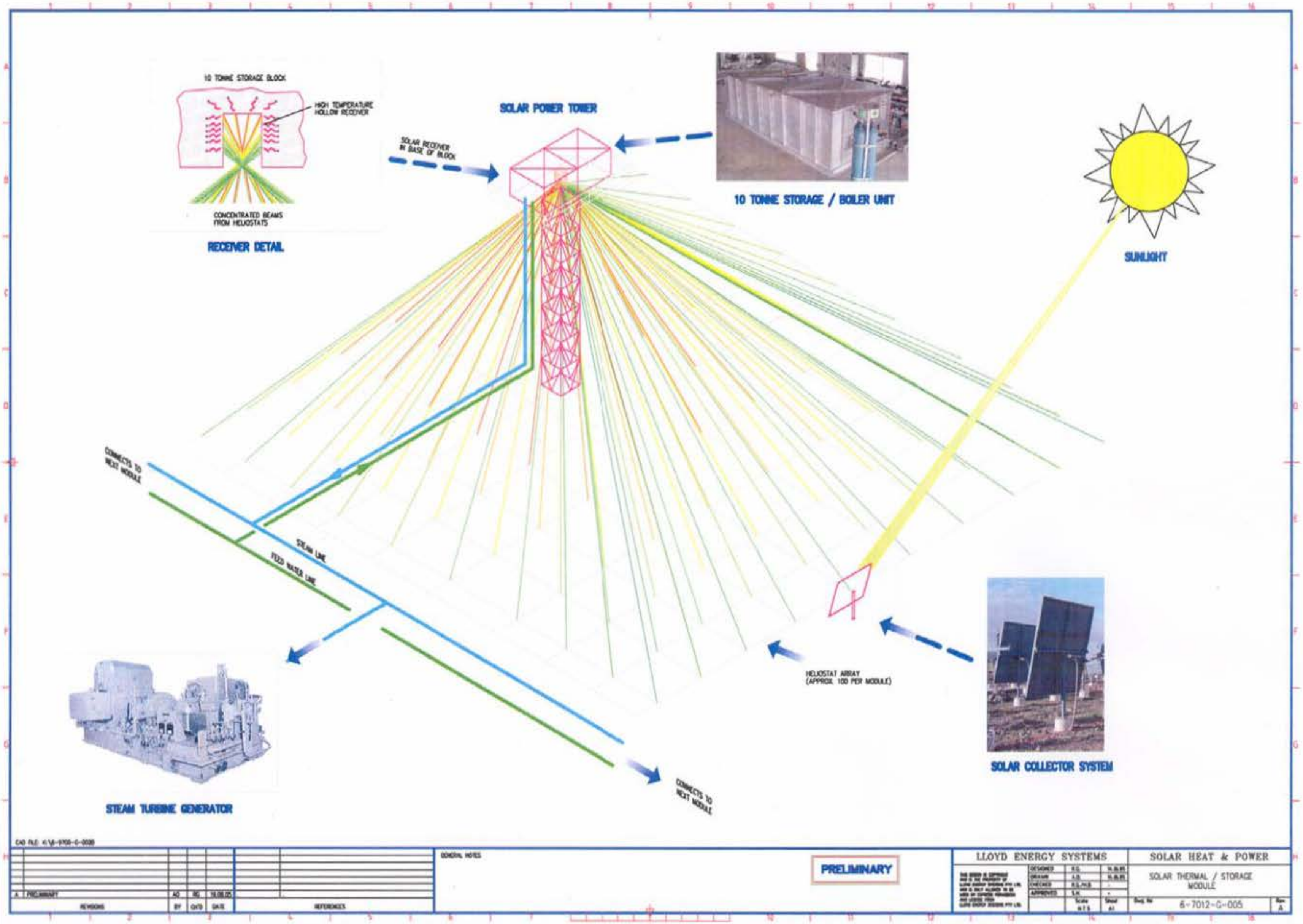
- Provide peak and backup supply for Cloncurry
- Ensure power quality in the area

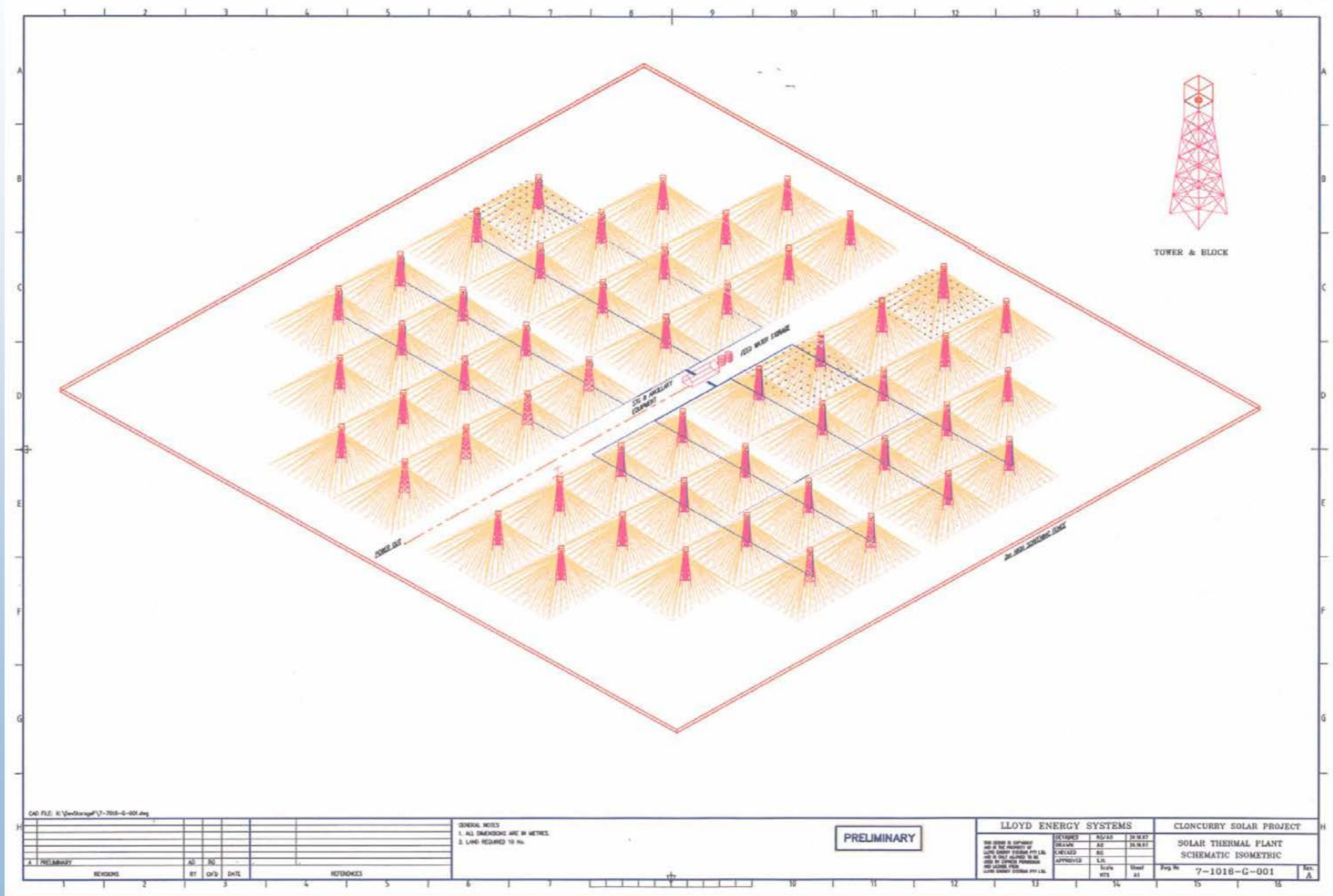
and

- Increase renewable energy use
- Reduce the need for more power transmission lines in the area in the future.

The Technology

- Solar energy is collected by tracking heliostats (mirrors) focusing the sun's rays directly into Lloyd storage boiler unit
- The thermal energy is stored in high purity graphite inside the unit with low losses
- The thermal energy is turned into electricity on demand by passing water through tubes embedded in the graphite to make steam
- The steam drives a turbine to generate electricity


10 TONNE STORAGE BLOCK
HIGH TEMPERATURE HOLLOW RECEIVER
CONCENTRATED BEAMS FROM HELIOSTATS
RECEIVER DETAIL
SOLAR POWER TOWER
SOLAR RECEIVER IN BASE OF BLOCK
10 TONNE STORAGE / BOILER UNIT
SUNLIGHT
CONNECTS TO NEXT MODULE
STEAM LINE
FEED WATER LINE
HELIOSTAT ARRAY (APPROX. 100 PER MODULE)
SOLAR COLLECTOR SYSTEM
STEAM TURBINE GENERATOR
CONNECTS TO NEXT MODULE
GENERAL NOTES
PRELIMINARY
LLOYD ENERGY SYSTEMS
SOLAR HEAT & POWER
SOLAR THERMAL / STORAGE MODULE
6-7012-G-005


TOWER & BLOCK
POWER OUT
PRELIMINARY
GENERAL NOTES
1. ALL DIMENSIONS ARE IN METRES.
2. LAND REQUIRED 10 Ha.
A PRELIMINARY AD RG
REVISIONS BY CH'D DATE
REFERENCES
LLOYD ENERGY SYSTEMS
DETAILED RG/AD
DRAWN AD
CHECKED RG
APPROVED L.H.
Scale NTS
Sheet A1
CLONCURRY SOLAR PROJECT
SOLAR THERMAL PLANT
SCHEMATIC ISOMETRIC
7-1016-G-001
Rev. A

Project Details

Solar Energy Collection

mirrors – total 60,000 square metres

Thermal Storage

54 modules, 540 tonnes, 80,000 kWh (electrical)

Electricity Generation Capacity

10,000 kW for 8 hours


31 JAN 2006
N
Proposed
Cloncurry Solar PS
Cloncurry Sewerage Works
Cloncurry Sub
© 2007 Europa Technologies
Image © 2007 DigitalGlobe
©2006 Google
Pointer 20°41'42.05" S 140°29'56.29" E elev 192 m
Streaming ||||||||| 100%
Eye alt 2.28 km

Project Financing

Cost

Lloyd and Financiers	$24,000,000
Queensland Gov't Contribution	$7,000,000
Total	$31,000,000

Revenue

Energy Purchase

and Network Support Fee - Ergon

Participants

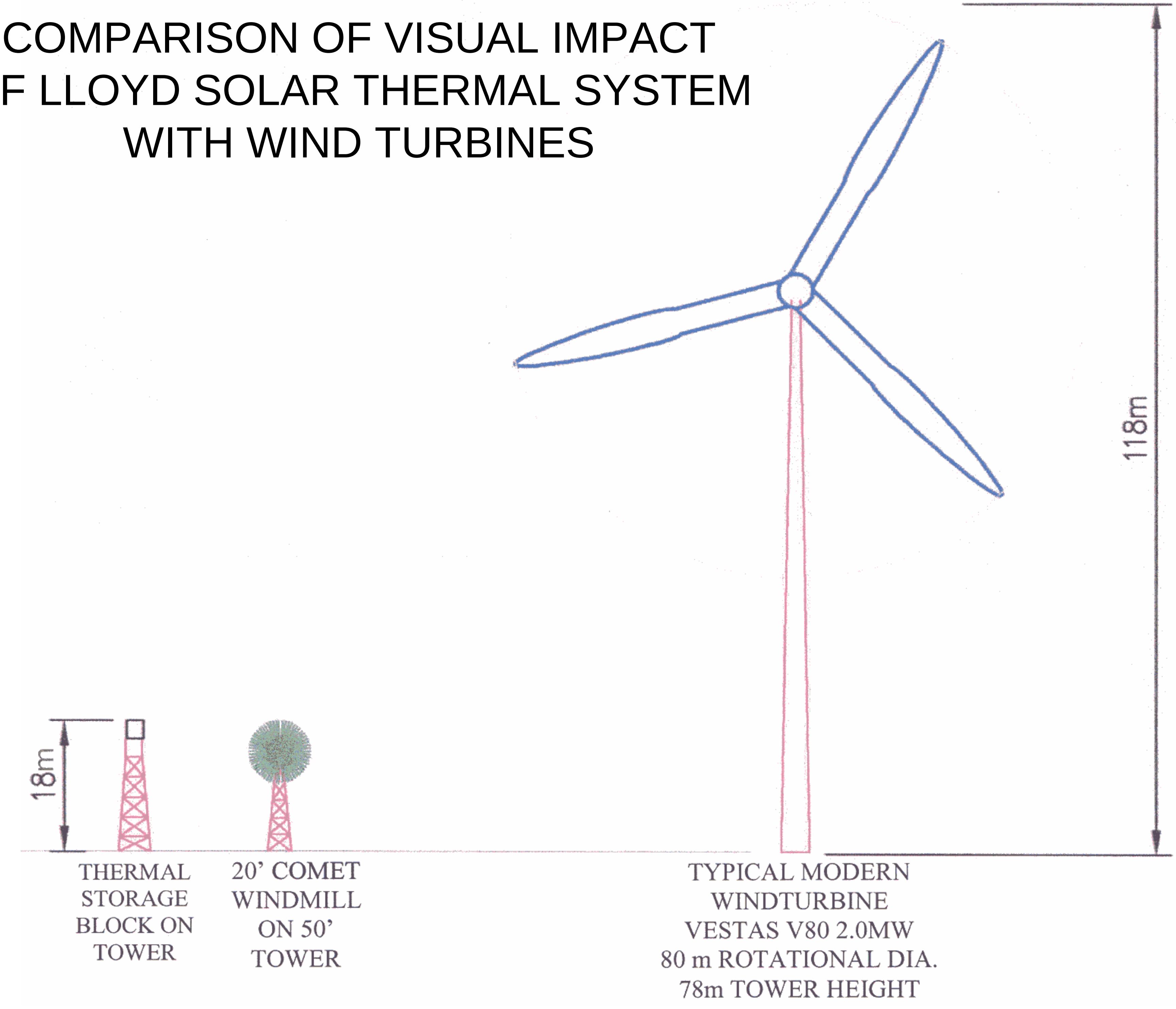
Project Delivery

- Lloyd Energy Systems Pty Ltd (LES)
  - LES (Storage Technology)
  - Solar Heat & Power P/L (Heliostats)
  - SMEC Pty Ltd (Engineering)
  - Ergon (Connections)
  - Local Contractors

Project Operation

LES

COMPARISON OF VISUAL IMPACT OF LLOYD SOLAR THERMAL SYSTEM WITH WIND TURBINES



First module being prepared for demonstration in Cooma NSW

Close up of solar receiver at base of storage/boiler unit

Similar heliostat array operating in Newcastle, NSW

The Project

will

Demonstrate solar energy “on-demand” through Lloyd’s solar storage system

to

- Provide peak power and backup supply for Cloncurry using solar energy

and

- Increase renewable energy use
- Reduce the need for more power transmission lines in the area in the future.

NREL PV-Watts

NASA Surface Meteorology and Solar Energy - Definitions
Link to: http://eosweb.larc.nasa.gov/sse/text/definitions.html

German FIT Commentary

Revolt of the Sun Kings: Solar Industry Fights to Save Subsidies - Energy and Natural Resources - Spiegel Online International
Link to: http://www.spiegel.de/international/germany/0,1518,690297,00.html

Birdsville Geothermal Plant

Birdsville Organic Rankine Cycle Geothermal Power Station - Ergon Energy
Link to: http://www.ergon.com.au/__data/assets/pdf_file/0008/4967/Birdsville-GeoThermal-ORC-Power-brochure.pdf

A new geothermal power station for Birdsville - The Oil Drum: Australia and New Zealand
Link to: http://anz.theoildrum.com/node/5507

Coastal Geothermal Drilling

Geothermal Energy - Queensland's Energy Futures - Queensland Government
Link to:
http://www.energyfutures.qld.gov.au/zone_files/Energy_general/geothermal_fact_sheet.pdf

Cost comparisons

Levelized Cost of Energy Analysis - version 2.0 - Lazard
Link to:
http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf

Renewable Energy Cost Trends - Energy Analysis Office / National Renewable Energy Laboratory
Link to: http://www.nrel.gov/analysis/docs/cost_curves_2002.ppt

Costs and Impacts

The Impact of PV Solar on Peak Electric Demands - William Post
Link to: http://www.coalitionforenergysolutions.org/impact_of_pv_solarapril5.pdf

European Commission

The support of electricity from renewable energy sources - Commission of the European Communities
Link to:
http://ec.europa.eu/energy/climate_actions/doc/2008_res_working_document_en.pdf

Geothermal Information

Feed-In Tariff in Germany - German Geothermal Society
Link to:
http://www.egec.org/target/strasbourg08/EGEC%20WS%20strasbourg%2011%20180608.pdf

2008 Geothermal Technologies Market Report - Energy Efficiency & Renewable Energy
Link to: http://www.osti.gov/bridge/servlets/purl/979824-NUMqAN/979824.pdf

The Heat in On - The Future of Energy in Australia - CSIRO
Link to: http://www.csiro.au/files/files/pbew.pdf

A Guide to Geothermal Energy and the Environment - Geothermal Energy Association
Link to: http://geo-energy.org/reports/Environmental%20Guide.pdf

Tim Flannery

Carbon capture 'unfeasible' - Tim Flannery
Link to: http://www.smh.com.au/business/flannery-ive-changed-my-mind-on-carbon-capture-20100526-we8u.html

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The German Renewable Energy Act – 2009

Chances & Risks under the Scope of an European Front-Runner

Dr. Marius Boewe
Counsel
+49 221 5771 233
mboewe@mayerbrown.com

Overview

RENEWABLE ENERGY
LAW SOLUTIONS
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- Introduction and background information
- History of current Renewable Energy Act (*EEG*)
- Operation mode of EEG
  - Energy sources
  - Feed-in tariffs
  - Burden sharing
- Case study

Background Information

RENEWABLE ENERGY
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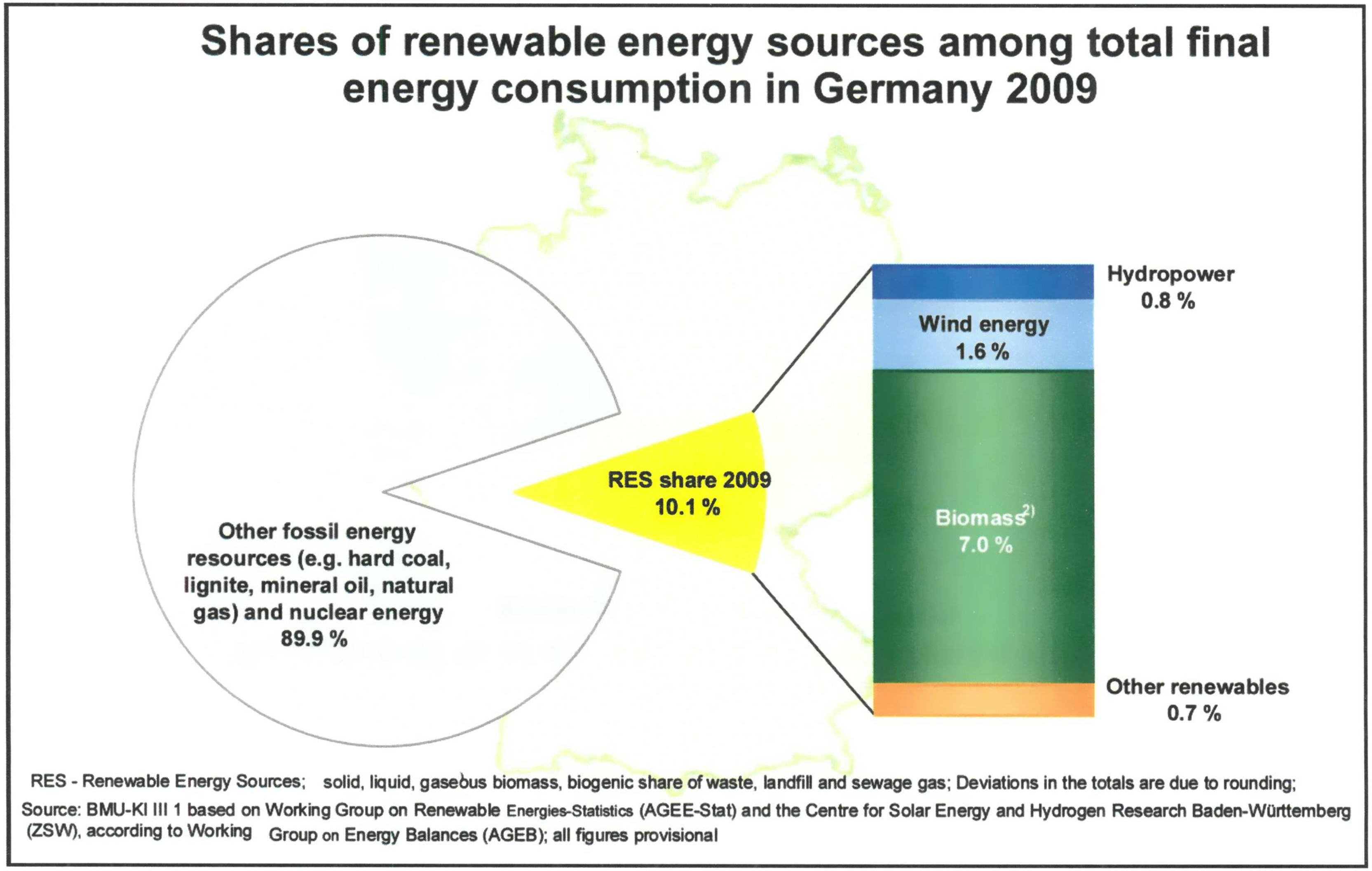

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Background Information

RENEWABLE ENERGY LAW SOLUTIONS
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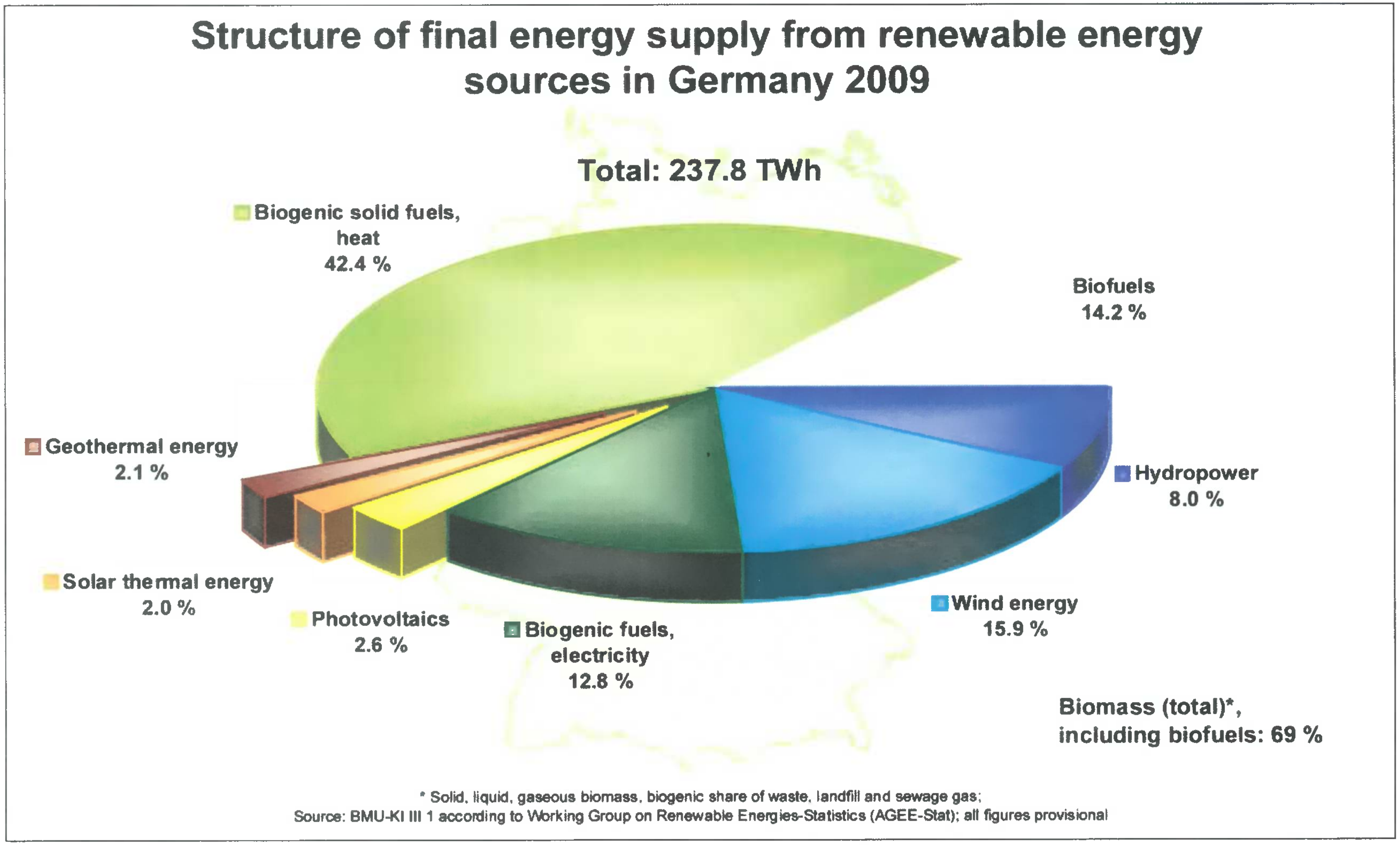
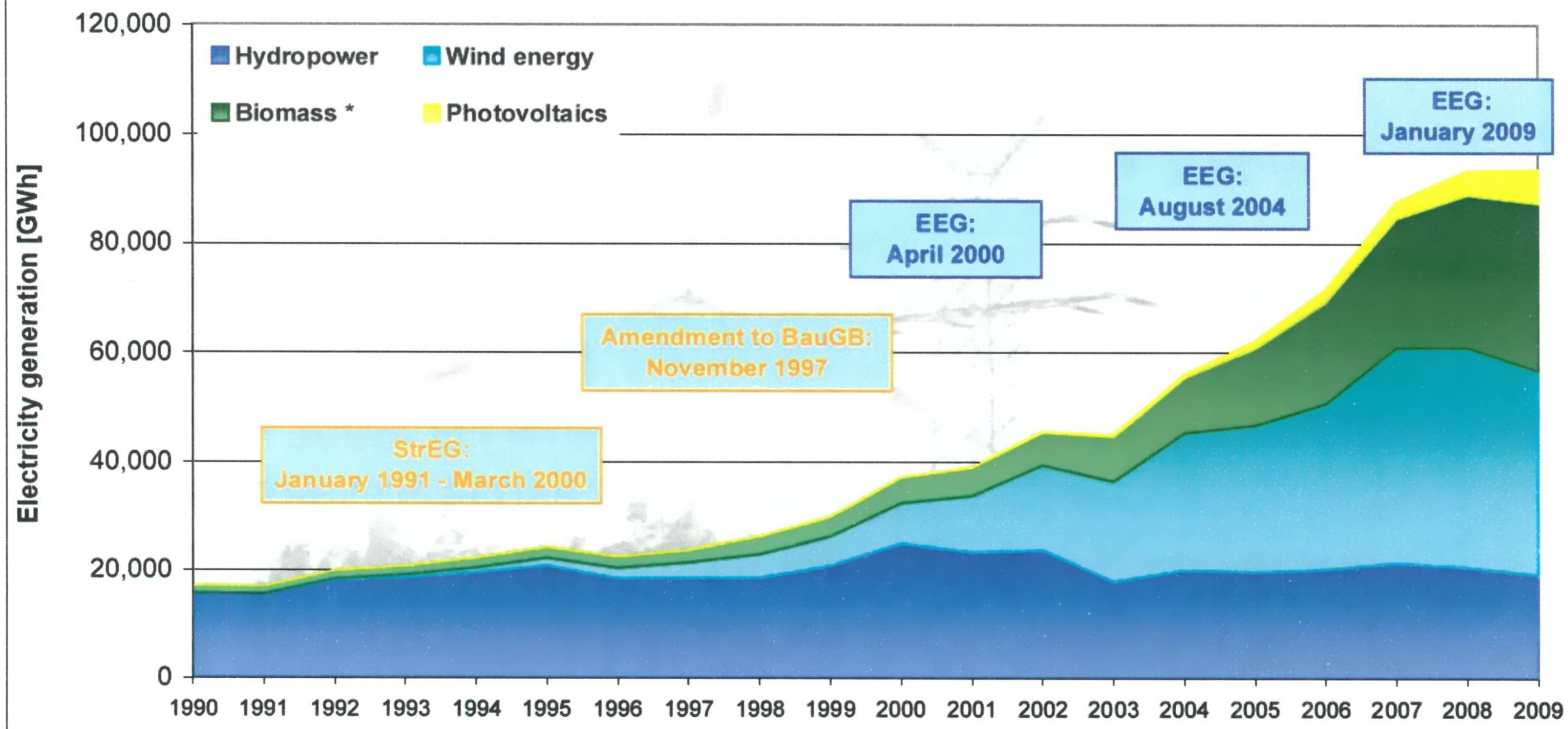


Background Information

Development of electricity generation from renewable energy sources in Germany 1990 - 2009



* Solid, liquid, gaseous biomass, biogenic share of waste, landfill and sewage gas;
Electricity from geothermal energy is not presented due to the negligible quantities of electricity produced; StrEG: Act on the Sale of Electricity to the Grid; BauGB: Construction Code; EEG: Renewable Energy Sources Act; Source: BMU-KI III 1 according to Working Group on Renewable Energies-Statistics (AGEE-Stat); Image: BMU / Christoph Edelhoff; all figures provisional

European Background

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- Dec.2008: Political agreement on the Renewables Directive
- 11.-12. Dec. 2008: EU summit agrees final version of the Renewables Directive (2009/28/EG)
- 30. June 2009: EU issues template for National Renewable Energy Action Plans (NREAPs)
- 30. June 2010: Deadline for EU states to present National Renewable Energy Action Plans
- 2020: Target date for EU objective of sourcing 20% of energy from renewable sources

Europeanwide Comparison of Shares in Renewable Energies by Member States

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Member State	Share of renewables in 2005	Share required by 2020
France	10.3%	23%
Germany	5.8%	18%
Italy	5.2%	17%
Spain	8.7%	20%
Sweden	39.8%	49%
United Kingdom	1.3%	15%

History of Current Act

- 1991: Renewable Energy Input Statute (*StromeinspeisungsG*)
  - First steps to guarantee feed-in of renewable energy producers
  - First legally guaranteed feed-in tariffs
  - Only profitable for wind power
- 2000: Renewable Energy Act 2000
  - Increasing the scope of reneweable energy sources
  - Raising the feed-in tariffs
- 2004: Renewable Energy Act 2004; and
- 2009: Renewable Energy Act 2009
  - Adjustments on tariffs, periods of sponsorship and degressions
  - 1 sec. 2 EEG 2009: by 2020 share of renewable energy sources shall at least amount to 30 percent

Operating Mode of EEG

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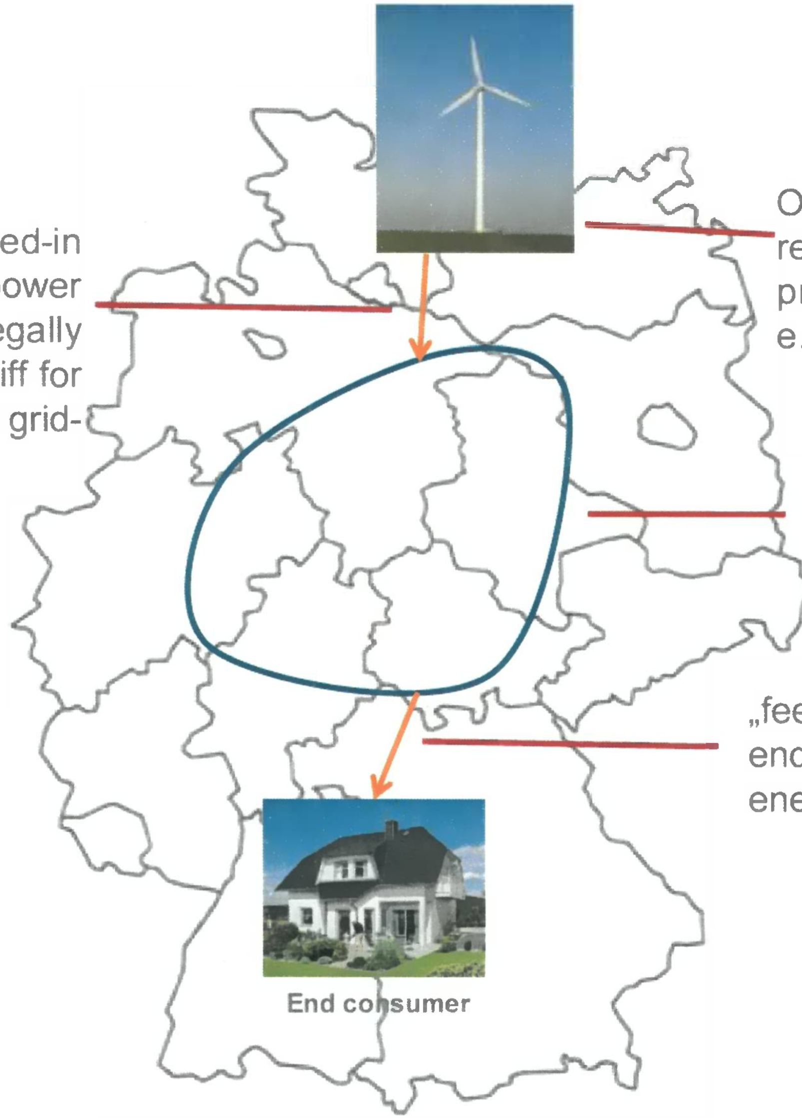

Renewable Energy Sources
Sec. 3 No. 3 EEG

- Hydropower (including wave power)
- Tidal power
- Salt gradient and flow energy
- Wind energy
- Solar radiation
- Geothermal energy
- Energy from biomass (incl. biogas)
- Landfill gas and sewage treatment gas
- Biodegradable fraction of waste

Feed-In Tariffs

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Feed-in tariffs depend on:

- Renewable energy sources
- Year of commissioning
- Capacity of power plant
- Degression

Examples of Feed-In Tariffs

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- Hydropower:

Capacity up to	500kW	500kW-2MW	2MW-5MW
	12.67 ct/kWh	8.65 ct/kWh	7.65 ct/kWh

- No degression; no difference in year of commissioning

Examples of Feed-In Tariffs

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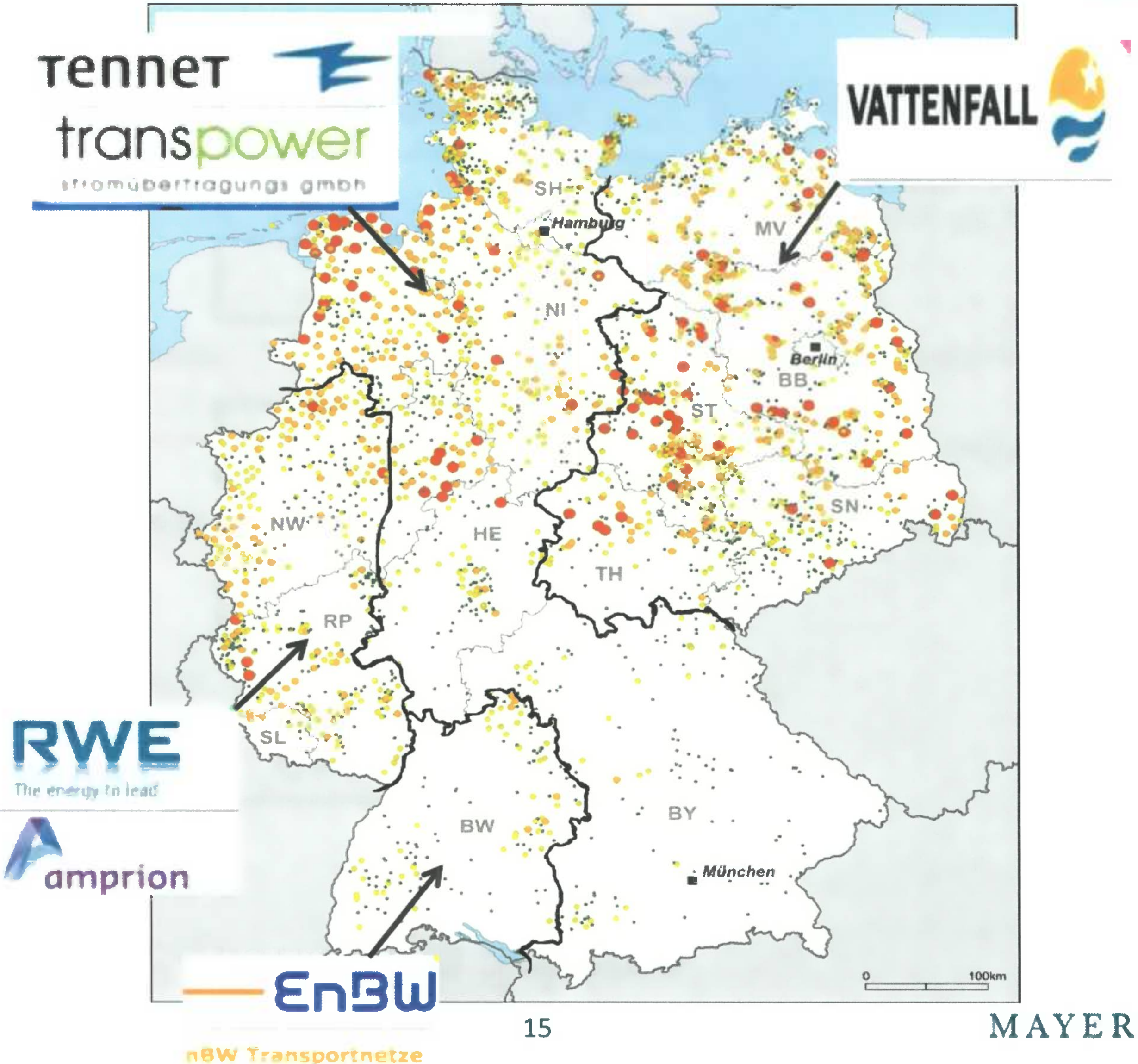
- Offshore wind energy:
  - Degression rate until 2014: 0.0 %; from 2015: 5%; duration of tariff payment: 20 years

	Initial tariff in ct/kWh for first 12 years	Early bird bonus during initial tariff period	Basic tariff in ct/kWh
2009	13	2	3.5
2010	13	2	3.5
2011	13	2	3.5
2012	13	2	3.5
2013	13	2	3.5
2014	13	2	3.5
2015	12.35	1.90	3.33
2016	11.73	0.0	3.16
2017	11.15	0.0	3.00
2018	10.59	0.0	2.85

Burden Sharing under the EEG

- Grid operator is obliged to
  - Accept entire amount of renewable energy
  - Pay legally guaranteed feed-in tariff
  - Sell renewable energy at spot market
- Grid operator is allowed to
  - Pass through difference between paid feed-in tariff and earned profit to end consumer („renewable energy contribution“)

Requirement for Compensation Mechanism for Practical Reasons



Consequence: Equalisation Scheme

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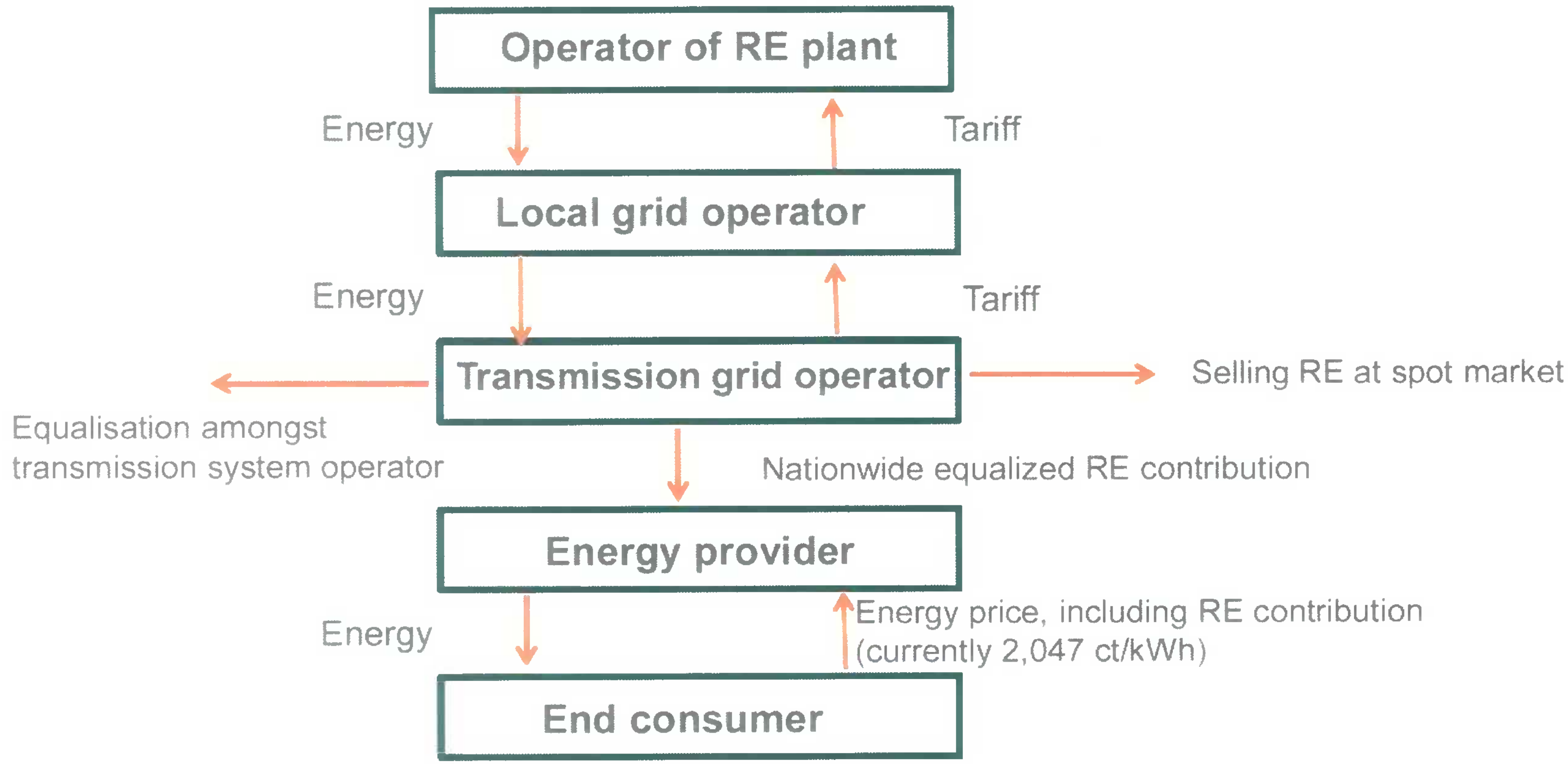

Case Study

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- Client runs biomass plant, revenue has been calculated on basis of EEG, which defines all relevant figures for 20 years.
  - Basic tariff + energy crops bonus (for using plants/parts of plants from agricultural operations, have not been treated or modified in any way)

- Calculated investment : 4.72 Mio €
- Calculated earnings by selling EEG-power: 1.275 Mio € (p.a.)

Case Study

RENEWABLE ENERGY
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Biomass plant originally used saw mill as energy source

- Issue: saw mill waste ≠ energy crop
- Client reaction: import of silvicultural waste from Netherlands
- Problem: very high proportion of soil/sand
  soil/sand outweighs wood 4-5 times
- Consequences: - as waste is delivered on m^3 basis and paid by weight, client paid for 450 kg/m^3 instead of 400 kg/m^3

  → 12 % higher costs
  → more waste required

  - sand melts in plant and slags mechanism

Further consequence:

- maintenance must be conducted 4 times a year (instead of 1 time)
- each maintenance lasts 1 week (additional costs)
- missing feed-in tariffs 100,000 € (*p.a.*)

Case Study

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- Client reaction: change of supplier
- Problem: new supplier (*inter alia*) contaminated wood (tar, plumb , *etc.*)
- Consequences:
  - -Client loses energy crops bonus (225,000 € *p.a.*)
  - -Client loses guarantee and warranty of plant for using improper fuel (sand, tar, *etc.*)
  - -Client violates various laws and was fined for:
    - -Unlawful operation of plant
    - -Unlawful combustion of contaminate waste (tar)

→ Actual Investment: 5.30 Mio € (+580 t € difference)

→ Actual EEG-earnings: 0.855 Mio € (-420 t € difference)

Contact

RENEWABLE ENERGY
LAW SOLUTIONS
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Dr. Marius Boewe
Counsel, Cologne
T.: +49 221 5771 233
E.: mboewe@mayerbrown.com

Australian Government
Bureau of Meteorology

Gridded Average Solar Exposure Metadata

Dataset	
Title	Monthly and annual solar exposure (base climatological data sets)
Custodian	
Custodian	Bureau of Meteorology
Jurisdiction	Australia
Description	
Abstract	Global solar exposure is the total amount of solar energy falling on a horizontal surface. The daily global solar exposure is the total solar energy for a day. Typical values for daily global exposure range from 1 to 35 MJ/m^2 (megajoules per square metre). For mid-latitudes, the values are usually highest in clear sun conditions during the summer, and lowest during winter or very cloudy days. These average data sets are based on 19 years (1990 - 2008) of solar exposure data derived from Japan Meteorological Agency and National Oceanographic & Atmospheric Administration satellite imagery. See LINEAGE below for more information.
Search Word(s)	Gridded, satellite, climatology, solar, radiation, exposure, meteorology
Geographic Extent Names(s)	Australia
General Category	Gridded climatological data
General Custodian Jurisdiction	Australian Government Australia
Geographic Extent Polygon	Not applicable
Geographic Bounding Box	See below
North Bounding Latitude	-11.00
South Bounding Latitude	-43.70
East Bounding Longitude	153.60
West Bounding Longitude	113.10
Data Currency	
Beginning Date	1990
Ending Date	2008
Dataset Status	
Progress	Completed
Maintenance and Update frequency	Ongoing

Access	
Stored Data Format	Arc/Info grids – all Australia
Available Format Type	ASCII row major, Arc/Info grid Interchange (.e00), Shapefiles.
Access Constraint	Satellite-derived global solar exposure estimates are based on images from the Geostationary Meteorological Satellite GMS-4, GMS-5, MTSAT-1R (from Nov. 2005) and Geostationary Operational Environmental Satellite (GOES-9) satellites which are provided with permission of the Japan Meteorological Agency (JMA) and the United States National Oceanic & Atmospheric Administration (NOAA). Any use of products from this imagery requires acknowledgement of the satellites of JMA and NOAA as the original source of the satellite data, and acknowledgement of the Commonwealth of Australia (Bureau of Meteorology) which received and processed the images. Acknowledgement should be in the form: "*Solar exposure data derived from satellite imagery processed by the Bureau of Meteorology from the Geostationary Meteorological Satellite series operated by Japan Meteorological Agency and from GOES-9 operated by the National Oceanographic & Atmospheric Administration (NOAA) for the Japan Meteorological Agency"* Please contact us (see details below) for more information.
Data Quality	
Lineage	The Bureau of Meteorology's computer radiation model uses visible images from geostationary meteorological satellites to estimate daily global solar exposures at ground level. At each location for each satellite acquired image, the brightnesses are averaged over each grid cell and used to estimate solar irradiance at the ground. Essentially, the irradiance at the ground can be calculated from the irradiance at the top of the earth's atmosphere, the amount absorbed in the atmosphere (dependant on the amount of water vapour present), the amount reflected from the surface (surface albedo) and the amount reflected from clouds (cloud albedo). These instantaneous irradiance values are integrated over the day to give daily insolation (daily radiant exposure) in megajoules per square metre. The daily exposure gridded datasets cover Australia with a resolution of 0.05 degrees in latitude and longitude. The maps for this dataset were produced by reprocessing archived raw satellite data using software that was extensively rewritten in 2006 but based on the physical model that has been used since 1990. Bias with respect to exposure estimates from Bureau of Meteorology ground instruments was removed by a linear adjustment to each month's maps. The monthly averages have been adjusted (to reduce the effect of missing days as solar declination changes) using the ratio of top-of-atmosphere exposure totals for the full month and for the sampled days.

Positional Accuracy	The satellite data on which the analyses were based have an associated resolution and typical accuracy of 0.05 degrees (5 km) up to and including June 1994 and 0.01 degrees (1.25 km) thereafter, although some individual images have errors of several km.
Attribute Accuracy	The accuracy of the model's daily estimates of solar exposure is estimated by comparison with measurements by Bureau of Meteorology ground instruments. The source of uncertainties associated with calculations includes: • Anisotropy of cloud-top reflectance. • Water vapour in the atmosphere. • Satellite calibration. • The availability of hourly images. The model assumes that hourly (or less frequent) 'instantaneous samples' of the irradiance will describe the conditions for the hourly (or longer) period. All these factors with both random and biased components means that the 95% uncertainty for any of the daily solar exposure estimates, regardless of the averaging period (that is, daily, monthly and seasonal), is of the order of 3 MJ/m^2. For more information (metadata) please contact us.
Logical Consistency	Not applicable
Completeness	All of the months for the period had at least half of their days sampled, with the vast majority missing no more than one day. GOES-9 ceased operation in November 2005.
Contact Information	
Contact Organisation	Bureau of Meteorology
Contact Position	NCC Information officer
Mail Address	PO BOX 1289, Melbourne 3001, Australia
Locality	
State	Victoria
Country	Australia
Postcode	3001
Telephone	(03) 9669 4082
Facsimile	(03) 9669 4515
Electronic Mail	webclim@bom.gov.au
Metadata date	
Metadata date	2009
Additional Metadata	Additional information available on request (see contact above)

__Parameters for Sizing and Pointing of Solar Panels and for Solar Thermal Applications:__

Monthly Averaged Insolation Incident On A Horizontal Surface (kWh/m^2/day)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	6.22	5.47	5.01	4.01	3.33	3.09	3.30	4.07	5.18	5.64	6.10	6.38	4.81

Minimum And Maximum Difference From Monthly Averaged Insolation (%)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Minimum	-12	-24	-20	-20	-18	-18	-21	-17	-12	-12	-15	-11
Maximum	14	16	13	17	17	15	15	20	13	18	15	10

Monthly Averaged Diffuse Radiation Incident On A Horizontal Surface (kWh/m^2/day)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	2.53	2.33	1.91	1.51	1.16	0.97	1.03	1.25	1.57	2.08	2.43	2.58	1.78
Minimum	2.32	2.15	1.73	1.31	0.98	0.80	0.84	0.92	1.29	1.75	2.18	2.42	1.55
Maximum	2.63	2.36	2.02	1.59	1.25	1.09	1.16	1.41	1.74	2.20	2.54	2.67	1.89
22-year Average K	0.52	0.49	0.52	0.51	0.52	0.55	0.55	0.57	0.58	0.54	0.52	0.52	0.53
Minimum K	0.46	0.37	0.41	0.41	0.43	0.45	0.44	0.47	0.51	0.47	0.44	0.46	0.44
Maximum K	0.59	0.57	0.59	0.60	0.61	0.63	0.64	0.68	0.66	0.64	0.60	0.58	0.62

NOTE:	*Diffuse radiation, direct normal radiation and tilted surface radiation are not calculated when the clearness index (K) is below 0.3 or above 0.8.*

Monthly Averaged Direct Normal Radiation ($kWh/m^2/day$)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	5.33	4.61	4.84	4.36	4.35	4.60	4.76	5.20	5.85	5.31	5.32	5.49	5.00

Minimum And Maximum Difference From Monthly Averaged Direct Normal Radiation (%)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Minimum	-14	-35	-26	-23	-19	-17	-21	-13	-10	-9	-18	-14
Maximum	21	26	17	24	21	16	16	22	14	25	22	14

NOTE:	*Diffuse radiation, direct normal radiation and tilted surface radiation are not calculated when the clearness index (K) is below 0.3 or above 0.8.*

Monthly Averaged Insolation Incident On A Horizontal Surface At Indicated GMT Times (kW/m^2)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average@00	0.66	0.60	0.59	0.51	0.44	0.41	0.42	0.52	0.64	0.66	0.69	0.69
Average@03	0.70	0.63	0.61	0.50	0.44	0.43	0.45	0.52	0.62	0.64	0.66	0.70
Average@06	0.38	0.34	0.28	0.18	0.12	n/a	0.13	0.18	0.24	0.26	0.30	0.36
Average@09	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@15	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@18	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@21	0.25	0.18	0.14	n/a	n/a	n/a	n/a	n/a	0.17	0.25	0.31	0.30

Monthly Averaged Insolation Clearness Index (0 to 1.0)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average K	0.52	0.49	0.52	0.51	0.52	0.55	0.55	0.57	0.58	0.54	0.52	0.52	0.53
Minimum K	0.46	0.37	0.41	0.41	0.43	0.45	0.44	0.47	0.51	0.47	0.44	0.46	0.44
Maximum K	0.59	0.57	0.59	0.60	0.61	0.63	0.64	0.68	0.66	0.64	0.60	0.58	0.62

Monthly Averaged Insolation Normalized Clearness Index (0 to 1.0)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
22-year Average	0.47	0.45	0.47	0.47	0.48	0.50	0.51	0.52	0.53	0.49	0.48	0.48

Monthly Averaged Clear Sky Insolation Incident On A Horizontal Surface ($kWh/m^2/day$)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	8.48	7.85	6.69	5.29	4.22	3.68	3.89	4.84	6.11	7.45	8.36	8.74	6.29

Monthly Averaged Clear Sky Insolation Clearness Index (0 to 1.0)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
22-year Average	0.71	0.71	0.69	0.67	0.66	0.65	0.65	0.67	0.69	0.71	0.72	0.72

Monthly Averaged Clear Sky Insolation Normalized Clearness Index (0 to 1.0)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
22-year Average	0.65	0.65	0.63	0.62	0.61	0.60	0.60	0.62	0.63	0.65	0.66	0.66

Monthly Averaged Downward Longwave Radiative Flux ($kWh/m^2/day$)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	9.30	9.34	9.07	8.76	8.41	7.98	7.78	7.75	7.99	8.49	8.81	9.08	8.55

Solar Geometry:

Monthly Averaged Solar Noon (GMT time)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	0158	0202	0157	0148	0144	0148	0154	0152	0143	0134	0132	0141

Monthly Averaged Daylight Hours (hours)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	13.6	13.0	12.2	11.4	10.7	10.4	10.6	11.1	11.9	12.7	13.4	13.8

Monthly Averaged Daylight Average Of Hourly Cosine Solar Zenith Angles (dimensionless)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	0.64	0.60	0.57	0.52	0.43	0.42	0.40	0.48	0.54	0.62	0.58	0.61

Monthly Averaged Cosine Solar Zenith Angle At Mid-Time Between Sunrise And Solar Noon (dimensionless)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	0.68	0.67	0.63	0.56	0.49	0.45	0.47	0.53	0.60	0.65	0.68	0.68

Monthly Averaged Declination (degrees)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-20.7	-12.3	-1.8	9.71	18.8	23.0	21.2	13.7	3.08	-8.45	-18.1	-22.8

Monthly Averaged Sunset Hour Angle (degrees)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	101	96.5	90.9	84.9	79.8	77.2	78.4	82.7	88.4	94.4	99.7	102

Monthly Averaged Maximum Solar Angle Relative To The Horizon (degrees)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	83.4	75.0	64.5	52.9	43.8	39.6	41.4	48.9	59.6	71.1	80.8	85.5

Monthly Averaged Hourly Solar Angles Relative To The Horizon (degrees)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000 GMT	62.4	57.8	52.2	44.7	37.4	33.3	34.2	40.7	50.7	60.9	66.9	66.9

0100 GMT	75.3	69.2	61.1	51.2	42.6	38.3	39.7	47.0	57.8	69.5	78.2	79.8
0200 GMT	83.4	75.0	64.4	52.8	43.7	39.5	41.4	48.8	59.3	70.1	78.8	83.7
0300 GMT	74.3	69.7	60.2	49.0	40.3	36.6	38.9	45.7	54.3	62.2	67.8	71.4
0400 GMT	61.3	58.5	50.9	41.0	33.2	30.2	32.6	38.5	45.1	50.6	54.8	58.1
0500 GMT	48.0	45.7	39.1	30.4	23.7	21.4	23.8	28.6	33.6	37.8	41.5	44.8
0600 GMT	34.7	32.5	26.4	18.5	12.7	10.8	13.2	17.2	21.1	24.6	28.2	31.6
0700 GMT	21.6	19.1	13.2	5.90	0.67	n/a	1.52	4.88	8.10	11.2	15.1	18.7
0800 GMT	8.85	5.97	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	2.34	6.22
0900 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1000 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1100 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1200 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1300 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1400 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1500 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1600 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1700 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1800 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1900 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.44	2.04
2000 GMT	9.90	5.30	1.66	n/a	n/a	n/a	n/a	n/a	2.30	9.67	14.2	14.4
2100 GMT	22.7	18.4	14.9	11.2	7.26	4.36	4.01	8.19	15.4	23.0	27.3	27.2
2200 GMT	35.8	31.8	28.0	23.6	18.8	15.5	15.5	20.3	28.3	36.2	40.6	40.3
2300 GMT	49.1	45.0	40.7	35.0	29.1	25.4	25.8	31.4	40.3	49.1	53.9	53.6

Monthly Averaged Hourly Solar Azimuth Angles (degrees)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000 GMT	82.7	68.4	52.5	38.9	31.4	29.7	32.4	36.9	43.2	53.8	71.4	84.5
0100 GMT	66.7	47.1	30.3	19.0	14.1	13.8	16.3	18.6	20.4	24.3	40.5	66.3
0200 GMT	355	1.62	357	354	354	356	358	357	351	340	323	313
0300 GMT	291	314	326	332	336	339	340	335	325	308	289	279
0400 GMT	276	292	305	314	320	324	324	318	307	291	277	270
0500 GMT	268	280	292	301	308	312	312	305	294	280	269	264
0600 GMT	262	272	282	292	299	303	302	296	285	273	262	258
0700 GMT	257	265	275	284	291	n/a	294	288	277	266	256	253
0800 GMT	251	259	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	250	247
0900 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1000 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1100 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1200 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1300 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1400 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1500 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1600 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1700 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1800 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1900 GMT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	109	114
2000 GMT	108	101	91.2	n/a	n/a	n/a	n/a	n/a	85.2	94.4	103	108
2100 GMT	102	94.7	84.2	72.8	64.4	61.2	63.5	69.7	78.0	87.6	97.3	103
2200 GMT	96.8	88.0	76.4	64.4	56.0	53.0	55.4	61.4	69.6	79.9	91.0	97.7

2300 GMT	90.7	79.9	66.6	53.6	45.3	42.7	45.3	50.9	58.7	69.8	83.4	92.1

Monthly Averaged Radiation Incident On An Equator-Pointed Tilted Surface ($kWh/m^2/day$)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
SSE HRZ	6.22	5.47	5.01	4.01	3.33	3.09	3.30	4.07	5.18	5.64	6.10	6.38	4.81
K	0.52	0.49	0.52	0.51	0.52	0.55	0.55	0.57	0.58	0.54	0.52	0.52	0.53
Diffuse	2.53	2.33	1.91	1.51	1.16	0.97	1.03	1.25	1.57	2.08	2.43	2.58	1.78
Direct	5.33	4.61	4.84	4.36	4.35	4.60	4.76	5.20	5.85	5.31	5.32	5.49	5.00
Tilt 0	6.19	5.34	4.95	3.98	3.23	3.02	3.22	4.04	5.12	5.52	6.07	6.35	4.75
Tilt 12	6.06	5.37	5.15	4.34	3.70	3.59	3.77	4.55	5.47	5.62	5.98	6.18	4.98
Tilt 27	5.64	5.18	5.18	4.60	4.11	4.12	4.28	4.98	5.65	5.50	5.61	5.70	5.05
Tilt 42	4.97	4.76	4.96	4.62	4.31	4.42	4.55	5.14	5.53	5.10	4.98	4.97	4.86
Tilt 90	2.09	2.25	2.80	3.20	3.39	3.73	3.74	3.83	3.37	2.48	2.13	2.04	2.92
OPT	6.19	5.38	5.20	4.64	4.32	4.48	4.60	5.14	5.65	5.62	6.07	6.35	5.30
OPT ANG	0.00	8.00	21.0	36.0	47.0	53.0	51.0	43.0	29.0	13.0	0.00	0.00	25.1

NOTE:	*Diffuse radiation, direct normal radiation and tilted surface radiation are not calculated when the clearness index (K) is below 0.3 or above 0.8.*

Minimum Radiation Incident On An Equator-pointed Tilted Surface ($kWh/m^2/day$)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
SSE MIN	5.48	4.17	4.01	3.22	2.73	2.54	2.62	3.37	4.54	4.96	5.19	5.66	4.04
K	0.46	0.37	0.41	0.41	0.43	0.45	0.44	0.47	0.51	0.47	0.44	0.46	0.44
Diffuse	2.63	2.36	2.02	1.59	1.25	1.09	1.16	1.41	1.74	2.20	2.54	2.67	1.89
Direct	4.58	2.97	3.55	3.33	3.51	3.78	3.73	4.52	5.26	4.79	4.36	4.68	4.10
Tilt 0	5.45	4.07	3.95	3.19	2.65	2.48	2.55	3.34	4.49	4.86	5.17	5.63	3.99
Tilt 12	5.35	4.08	4.07	3.42	2.96	2.87	2.90	3.69	4.75	4.93	5.10	5.50	4.14
Tilt 27	5.01	3.94	4.07	3.56	3.23	3.21	3.21	3.96	4.87	4.81	4.81	5.10	4.15
Tilt 42	4.46	3.64	3.88	3.54	3.33	3.39	3.35	4.04	4.75	4.48	4.31	4.50	3.97
Tilt 90	2.01	1.90	2.26	2.43	2.57	2.79	2.68	2.96	2.92	2.27	2.01	1.99	2.40
OPT	5.45	4.09	4.09	3.57	3.33	3.41	3.36	4.04	4.87	4.93	5.17	5.63	4.33
OPT ANG	0.00	7.00	19.0	32.0	44.0	50.0	47.0	40.0	27.0	12.0	0.00	0.00	23.2

NOTE:	*Diffuse radiation, direct normal radiation and tilted surface radiation are not calculated when the clearness index (K) is below 0.3 or above 0.8.*

Maximum Radiation Incident On An Equator-pointed Tilted Surface ($kWh/m^2/day$)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
SSE MAX	7.09	6.33	5.68	4.71	3.89	3.56	3.80	4.87	5.87	6.67	7.03	7.03	5.54
K	0.59	0.57	0.59	0.60	0.61	0.63	0.64	0.68	0.66	0.64	0.60	0.58	0.62
Diffuse	2.32	2.15	1.73	1.31	0.98	0.80	0.84	0.92	1.29	1.75	2.18	2.42	1.55
Direct	6.46	5.84	5.71	5.44	5.29	5.38	5.53	6.38	6.69	6.67	6.51	6.30	6.02
Tilt 0	7.06	6.18	5.60	4.67	3.78	3.48	3.71	4.83	5.80	6.53	7.00	7.00	5.47
Tilt 12	6.89	6.23	5.86	5.18	4.42	4.23	4.44	5.57	6.25	6.68	6.88	6.79	5.78
Tilt 27	6.38	6.01	5.93	5.56	4.99	4.94	5.12	6.21	6.50	6.54	6.41	6.23	5.90
Tilt 42	5.55	5.49	5.68	5.64	5.29	5.36	5.51	6.48	6.39	6.06	5.64	5.38	5.71
Tilt 90	2.12	2.43	3.14	3.93	4.23	4.60	4.60	4.90	3.86	2.76	2.19	2.04	3.41
OPT	7.06	6.23	5.94	5.65	5.32	5.48	5.59	6.49	6.51	6.68	7.00	7.00	6.25
OPT ANG	0.00	9.00	22.0	38.0	49.0	55.0	53.0	45.0	30.0	14.0	0.00	0.00	26.3

NOTE:	*Diffuse radiation, direct normal radiation and tilted surface radiation are not calculated when the clearness index (K) is below 0.3 or above 0.8.*

Cloud Information:

Monthly Averaged Daylight Cloud Amount (%)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	61.5	62.7	53.8	56.1	48.8	40.1	36.2	36.7	35.6	53.2	60.4	60.5	50.4

Monthly Averaged Cloud Amount At Indicated GMT Times (%)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average@00	65.2	66.5	54.7	46.9	41.3	34.4	28.5	29.9	34.2	56.4	64.9	65.0
Average@03	70.5	73.8	69.2	67.5	56.8	45.7	42.4	45.4	47.1	62.5	70.9	69.1
Average@06	63.2	65.4	58.6	53.9	48.3	n/a	37.8	34.9	35.7	52.9	60.7	61.2
Average@09	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@15	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@18	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average@21	47.3	45.3	32.6	n/a	n/a	n/a	n/a	n/a	25.2	41.1	45.1	46.9

Monthly Averaged Frequency Of Clear Skies At Indicated GMT Times (%)												
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
< 10% @0	15.9	16.4	22.1	29.2	38.7	47.8	55.5	52.7	49.0	29.7	21.8	21.7
< 10% @3	12.9	11.2	13.7	13.4	24.6	35.9	40.1	38.7	36.5	22.7	15.7	17.7
< 10% @6	15.5	13.8	18.7	20.9	22.2	n/a	43.9	44.1	45.1	28.3	20.7	19.9
< 10% @9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
< 10% @12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

< 10% @15	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
< 10% @18	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
< 10% @21	28.5	29.2	43.8	46.8	n/a	n/a	n/a	55.6	54.7	38.5	31.3	27.1

Monthly Averaged Frequency Of Broken-cloud Skies At Indicated GMT Times (%)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10 - 70% @0	27.8	23.7	34.0	34.0	27.8	25.0	22.7	24.4	23.9	18.3	17.8	17.1
10 - 70% @3	23.3	19.6	22.1	25.1	26.3	24.0	24.6	21.5	22.8	21.1	17.8	16.5
10 - 70% @6	30.2	28.9	33.5	36.9	34.8	n/a	27.0	30.2	28.0	26.9	26.5	26.6
10 - 70% @9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10 - 70% @12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10 - 70% @15	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10 - 70% @18	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10 - 70% @21	35.3	38.2	34.9	31.0	n/a	n/a	n/a	25.2	29.7	28.7	36.0	38.2

Monthly Averaged Frequency Of Near-overcast Skies At Indicated GMT Times (%)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
>= 70% @0	56.1	59.8	43.8	36.6	33.4	27.1	21.7	22.7	26.9	51.9	60.3	61.1
>= 70% @3	63.7	69.1	64.0	61.3	48.9	40.0	35.1	39.7	40.6	56.1	66.3	65.6
>= 70% @6	54.2	57.2	47.6	42.1	42.8	n/a	29.0	25.6	26.8	44.7	52.7	53.3
>= 70% @9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
>= 70% @12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
>= 70% @15	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
>= 70% @18	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

>= 70% @21	36.0	32.4	21.2	22.1	n/a	n/a	n/a	19.1	15.6	32.7	32.5	34.6

Meteorology (Temperature):

Monthly Averaged Air Temperature At 10 m Above The Surface Of The Earth (°C)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	23.7	23.8	23.1	21.9	20.1	18.1	17.2	17.7	19.4	20.6	21.5	22.8	20.8
Minimum	22.3	22.6	21.9	20.6	18.8	16.6	15.5	15.9	17.6	19.0	20.0	21.4	19.3
Maximum	25.0	25.0	24.3	23.2	21.4	19.6	18.9	19.5	21.4	22.3	23.0	24.2	22.3

Average Daily Temperature Range (°C)

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
25-year Average	2.63	2.43 *	2.43	2.56	2.64	2.96	3.37	3.61	3.77	3.34	2.96	2.77

Monthly Averaged Cooling Degree Days Above 18 °C

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Sum
25-year Average	176	164	158	117	69	25	11	16	51	83	104	149	1123

Monthly Averaged Heating Degree Days Below 18 °C

Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Sum
25-year Average	0	0	0	0	1	21	35	25	5	0	0	0	87

Monthly Averaged Earth Skin Temperature (°C)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
25-year Average	25.7	25.8	25.0	23.8	22.2	20.5	19.5	19.6	20.8	22.2	23.5	24.7	22.8

Average Minimum, Maximum and Amplitude Of The Daily Mean Earth Temperature (°C)													
Lat -27.3 Lon 153.1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Amplitude
Minimum	24.4	24.7	24.0	22.8	21.2	19.5	18.3	18.2	19.3	20.7	22.1	23.4	
Maximum	27.4	27.4	26.7	25.5	23.8	22.1	21.2	21.5	22.9	24.2	25.4	26.5	
Amplitude	1.49	1.33	1.32	1.34	1.28	1.31	1.44	1.64	1.80	1.73	1.64	1.53	4.61

Jeff Seeney MP

Shadow Minister for Natural Resources, Mines & Energy

Member for Callide

28 May 2010

Bligh Labor was spending up big advertising for people to do the “bright thing” and install solar panels but can’t even do the “bright thing” and fund Cloncurry’s promised solar/thermal power station.

LNP energy spokesman Jeff Seeney said Anna Bligh proclaimed the Cloncurry solar plant as a “real breakthrough for electricity generation”.

“It should have been up and running last year but there’s no sign of it coming on line,” Mr Seeney said.

“The Bligh Government was to provide $7 million towards this $31 million project, but nothing’s happened except an eyesore,” Mr Seeney said.

Mr Seeney said a Government website (below) spruiked how Cloncurry would be the first Queensland town to produce solar/thermal power to supply electricity needs 24/7 through a 10 megawatt power station that would generate power even when the sun was not shining.

http://www.energyfutures.qld.gov.au/solar_challenges_and_opportunities_.cfm

Up to 8000 mirrors would reflect concentrated sunlight on graphite blocks with water pumped through the blocks generating steam to drive a turbine generator.

“All good we were told, except nothing is happening and even the Office of Clean Energy has wiped all records of this project from its website.

“The questions must be asked …what is the Government hiding. What’s happened to this clean, green initiative …why has it been deleted from the Office of Clean Energy’s website.”