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A Country Comparison of Risks and Opportunities

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List of Abbreviations

AD	Anaerobic digestion (biogas)
ADB	Asia Development Bank
APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of Southeast Asian Nations
BAPV	Building-attached photovoltaic
BIPV	Building-integrated photovoltaic
CDM	Clean Development Mechanism of the Kyoto Protocol
CER	Certified Emissions Reduction certificate (part of the CDM)
CHP	Combined heat and power
DSO	Distribution system operator
EU	European Union
FIT	Feed-in tariff
FY	Fiscal year
GDP	Gross domestic product
GHG	Greenhouse gases
IEA	International Energy Agency
IMF	International Monetary Fund
ktoe	Kilo tonnes of oil equivalent
Mtoe	Million tonnes of oil equivalent
OECD	Organisation for Economic Cooperation and Development
PV	Photovoltaic
RE	Renewable energy
RPS	Renewable Portfolio Standard
TGC	Tradable green certificates
TSO	Transmission system operator
UNDP	United Nations Development Programme
UNFCCC	UN Framework Convention on Climate Change
VAT	Value added tax

Chapter 1: Introduction

1.1 Overview

This report provides a detailed analysis of the renewable electricity sector in 11 countries in the Asia-Pacific region: Australia, China, India, Indonesia, Japan, Malaysia, the Philippines, South Korea, Taiwan, Thailand and Vietnam. These are key countries for investors in the sector.

The Asia-Pacific region is becoming increasingly important as a driver of world economic growth and as an investment destination. Some international investors in renewable power development have already set foot in the region. At a time when the European and North American markets are becoming increasingly saturated with investors looking for opportunities, the Asia-Pacific region has come to represent the next opportunity.

In the region today, the main drivers for renewable power deployment are greenhouse gas emissions reduction targets, and the recognition that renewable power can be a partial solution to the rapidly increasing demand for electricity, while enhancing energy security. For developing countries in the region, added to these drivers are the challenges presented by the need for rural electrification. As renewable power technologies become more accessible and renewable power generation costs decrease further, the development of renewable power is expected to accelerate in the region.

A regulatory framework to promote renewable power deployment is already in place in many of the countries of the region. However, the power market is often tightly controlled by incumbents under a vertically-integrated structure of the power sector. In addition, for both domestic and foreign developers, lack of grid capacity and uncertainty for development permits are major risks. Nevertheless, the region in general offers significant opportunities for renewable power development because of the drivers for renewable power.

In this report, the renewable electricity sector of each country is assessed in terms of both opportunities and risks for investors by using a series of indices that measure:

- incentive opportunities
- power market opportunities
- renewable power technologies opportunities
- political will risks
- grid connection risks
- planning permission risks

Each index consists of multiple measures that accurately and numerically evaluate the opportunities or risks concerned. The only exception is the technologies opportunities index, which is not evaluated numerically. This approach allows for a thorough understanding of the specific commonalities and differences between countries with respect to their renewable electricity sectors and provides a means to determine the trends and movements in the region as a whole.

Provided below is an explanation of government incentive systems operated to promote renewable power development and a detailed description of the indices used.

1.2 Government Incentives

Renewable electricity development projects are generally not financially feasible without government incentives. Universally, there are two types of incentives: schemes to support operation of renewable power installations, which are offered per unit of electricity produced; and schemes to support investment in renewable power development, which are usually awarded in the form of direct aid, soft loans or tax benefits. Although investment support can be substantial, it offers less security to prospective investors, since the availability of funding often depends on lodging an early application, and the amount offered may not be known until details of a project are presented. According to the European Commission, operating incentives are more effective than investment support programmes.[1]

There are four major operating support schemes used worldwide:

1. Feed-in tariffs (FITs)
2. Fixed and variable premiums
3. Tradable green certificates (TGCs), also known as a Renewables Portfolio Standard (RPS)
4. Tendering schemes

The implementation of these operating support schemes varies greatly among countries; however, the basic principles that underpin each scheme are very similar.

1.2.1 Operating Support Schemes

Most countries have one or a combination of the following three types of support schemes: feed-in tariffs, premiums, and tradable green certificates. The specifics of those schemes vary between countries. In addition, tender schemes are used in some countries for specific types of projects.

Feed-in Tariffs

A feed-in tariff (FIT) system is a renewable electricity-generation incentive that guarantees a fixed price and buyer for electricity. It requires electricity network operators to purchase all the output that renewable electricity generators supply to the grid at a set price, regardless of whether or not the output is needed to satisfy demand at the time—this is known as an "obligatory purchase." The FIT rates and duration of each FIT vary among countries and are specific to each renewable electricity generation technology employed. In some countries, generators can receive the FIT even for electricity that is not supplied to the grid but consumed for their own use.

The FIT rates are, in most cases, subject to adjustments over time. In some countries, the

[1] Commission of the European Communities, The Support of Electricity from Renewable Energy Sources, 2008, pp. 4–5. COM(2008)18. Available at <ec.europa.eu/energy/climate_actions/doc/2008_res_working_document_en.pdf>.

tariff rates are periodically re-evaluated, while in others they are set for a period and thereafter lowered at a predetermined annual rate. The latter is termed a degression rate. In both instances, these adjustments seek to correlate more accurately the fixed tariff price with the projected declines in generation cost as renewable electricity generation technologies and component supply chains mature.

The use of a FIT system is considered to be a relatively good incentive for driving investment in renewable power development as it offers a degree of predictability to revenue through the predetermined price and a guaranteed buyer. Its success appears to be borne out by recent trends in the EU where the largest growth in renewable electricity investment and development has occurred in countries using FITs as the primary support system.

The FIT incentive system, however, is seen as less market-oriented than other incentive schemes as it shields renewable electricity generators from variability in the open wholesale electricity market. As the grid operators are obliged to take all renewable electricity generated, there is some concern about the effect of large amounts of intermittent renewable power on the grid and the spot market.

Fixed and Variable Premiums

A variation on the FIT model is the premium incentive, also known as the green bonus scheme. Under the premium system, generators sell their output on wholesale electricity markets at the same prices and under identical conditions as all other electricity generators. There is no purchase guarantee as found under the FIT system, although in some countries renewable electricity is given priority for purchase. To cover the costs of generating power from renewable energy sources under the premium system, generators are entitled to receive a supplementary amount, or “premium,” for every megawatt hour (MWh) of electricity they sell, in addition to the market price of electricity. The premium is paid for by the relevant government agency or network operator, and the cost is then recovered through a tax on electricity sales or from the government’s general budget.

There are two types of premium: fixed and variable. Under a fixed premium, the generator receives a set premium for each unit of output sold on the open market regardless of the market price of electricity.

With a variable premium, the generator receives a variable amount, calculated as the difference between the market price at the time of sale and a predetermined higher price, normally set by a government agency. To illustrate the difference between fixed and variable premiums, hypothetical examples of both types of premium are provided below.
Under the fixed premium system, a spot market electricity price of 55 EUR/MWh and a fixed premium of 33 EUR/MWh provide a generation compensation of 88 EUR/MWh.

If the market price falls to 45 EUR/MWh, the fixed premium remains 33 EUR/MWh and hence the generation compensation drops to 78 EUR/MWh. Under the variable premium system, if the predetermined guaranteed revenue is 88 EUR/MWh, the market price then falls from 55 EUR/MWh to 45 EUR/MWh, and the premium is adjusted from 33 EUR/MWh to 43 EUR/MWh to compensate for this drop. If there was an increase in the wholesale electricity price to 60 EUR/MWh, generation compensation, under the fixed premium, would increase to 93 EUR/MWh, which was made up of the 60 EUR/MWh price of electricity and the fixed 33 EUR/MWh premium. Under the variable premium system, the premium would fall to 28

EUR/MWh to maintain the generation compensation at 88 EUR/MWh.

Tradable Green Certificates

Under the tradable green certificate (TGC) incentive system, renewable electricity generators sell their output on the wholesale market at the same prices and under identical conditions as all other electricity generators. For every MWh of renewable electricity supplied to the grid, one TGC is awarded to the renewable electricity generator. The TGC can then be sold by the generator to an electricity supplier or distributor, either directly or through a TGC market. Demand for TGCs is created through a quota obligation, whereby suppliers or distributors are obliged to present a set number of TGCs to the regulator every year according to their sales volume. If suppliers fall short of their quota obligations, they will need to pay a penalty for each outstanding TGC. In most TGC systems, TGCs can be banked for use in later periods.

The TGC system is generally considered more market-driven than other systems because both the TGC and electricity prices fluctuate according to supply and demand. Generators are urged to improve efficiency, and, in the longer term, align their generation costs to those of non-renewable electricity providers.

There are, however, concerns regarding the TGC system. One concern is that it does not adequately distinguish between more established renewable electricity technologies with comparatively low generation costs, and emerging technologies with higher generation costs. Therefore, only mature and established technologies can be effectively supported and the ability of the TGC system to promote broader renewable electricity generation development is limited. There is a system known as "technology banding" in some countries, where certain technologies, such as solar PV, receive a greater number of TGCs for each MWh of electricity supplied than more established and more cost efficient technologies such as landfill gas.

Another concern relates to the stability of the TGC market. The TGC system relies on the demand for TGCs created by the quota system to drive the market price to a point at which their sale by renewable electricity generators can adequately cover the relatively high generation costs of renewable electricity. Should the TGC quota obligations on electricity suppliers or distributors be too low, the TGC supply would exceed demand and as a result the price of the TGCs could collapse. This susceptibility to fluctuations in the TGC price creates a considerable long-term investment risk.[2]

To reduce this risk, some TGC schemes provide a support mechanism for the TGC market in the form of a "market maker." Generally, the market maker is established and supported by the country's transmission system operator (TSO), which commits to buying and selling TGCs at a minimum or "reference" price. The market maker removes the risk of a TGC market collapse. In practice, the minimum price set by the market maker is below the average price of the TGCs sold on the open market.

[2] Robert Gross, Philip Heptonstall, and William Blyth, Investment in Electricity Generation: The Role of Costs, Incentives and Risks, UKERC, May 2007. Available at <www.ukerc.ac.uk/Downloads/PDF/07/0705TPAInvestmentReport/0705InvestmentReport.pdf>.

Tender Schemes

Renewable electricity tender schemes employ a form of competitive tendering whereby an electricity supply contract is offered. Under this contract, the government or a network operator guarantees to purchase a predetermined amount of electricity generated using a specific renewable electricity generation technology. Developers submit tenders for the project concerned, competing according to the lowest price at which they are able to supply the renewable electricity output. In theory, this scheme should drive the output price of renewable electricity to its lowest possible level. In practice, however, this incentive scheme can lead to renewable electricity generators providing unrealistically low generation cost estimates in their tenders.

Tender schemes were used extensively in the past, but they have become less popular as more sophisticated incentive schemes such as FIT systems have been introduced. On the whole, however, tender schemes are not considered to be a particularly successful incentive system and have been ineffective at increasing renewable electricity generation.[3]

1.2.2 Investment Support Schemes

Investment support schemes are normally defined as financial assistance that covers a part of the initial capital investment cost of a project. They usually take the form of capital grants, soft loans, and tax reductions or exemptions on the purchase of goods, and are generally applied as a secondary incentive scheme to an operating incentive scheme.[4]

Identifying the full range of investment support programmes in a country at a point in time can be time-consuming, as they are funded and managed by different government or quasi-government offices often at the national, regional and local levels. Investment support programmes often have a cap as they are generally funded under the government budget. When the fund is disbursed, the programme ends and it is not certain when a similar programme will next be created. Eligibility for a programme is not necessarily clear until the details of a project are presented to the concerned authority. This report, for reasons of conciseness, accuracy and simplicity, will focus primarily on the investment support schemes provided by national or federal governments.

1.3 Opportunity and Risk Indices

We have developed indices to quantitatively assess the current investment climate of the renewable electricity sector in different countries from the viewpoint of both opportunities and risks. These indices cover critical areas that determine the overall level of opportunities and risks in the country concerned. Each index further consists of a series of sub-indices or measures to provide a comparative value for each of the key features of the primary indices (except the technology opportunity index). The specific structure and details of the indices and sub-indices are provided below.

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[3] OPTRES, Assessment and Optimisation of Renewable Energy Support Schemes in the European Electricity Market, February 2007, pp. 1–17. Available at <www.optres.fhg.de/OPTRES_FINAL_REPORT.pdf>.
[4] Commission of the European Communities, The Support of Electricity from Renewable Energy Sources. Available at <ec.europa.eu/energy/climate_actions/doc/2008_res_working_document_en.pdf>.

A. Opportunities Indices

1. **Incentive Opportunities Index**: How attractive to investors and developers are the government's incentives for renewable electricity development?
2. **Power Market Opportunities Index**: How much demand is there or will there be for renewable electricity?
3. **Technology Opportunities Index**: What types of renewable electricity technologies are already established and which are emerging in the market concerned?

Measures or sub-indices are set for the first two indices to give a quantitative (ordinal) scale from a total of zero to five, with five being the most encouraging for renewable electricity development. Those measures are as follows:

1. Incentive Opportunity Index (maximum 5 points)

Measures	Description
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.*
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.*

2. Power Market Opportunity Index (maximum 5 points)

Measures	Description
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*

3. Technology Opportunity Index

Measures	Description
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*

B. Risk Indices

1. **Political Will Risk Index**: How committed is the government in question to meeting its pledged targets on renewable energy and electricity and how stable is renewable electricity development on the political agenda?
2. **Grid Connection Risk Index**: How serious is the problem of grid connection for renewable electricity installations?
3. **Planning Permission Risk Index**: How serious is the problem of securing planning permission for renewable electricity installations?

Again, measures are set for each of the three indices to give a quantitative (ordinal) scale from a total of zero to five, with five being the highest level of risk involved in investing in renewable electricity in the market concerned. Those measures are as follows:

4. Political Will Risk Index (maximum 5 points)

Measures	Description
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. *A high debt ratio may lead to negative change in the incentive policy for renewable energy.*
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.

5. Grid Connection Risk Index (maximum 5 points)

Measures	Description
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.

6. Planning Permission Risk Index (maximum 5 points)

Measures	Description
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*

The multiple measures explained above do not necessarily cover all the dimensions of each index in an exhaustive or exclusive manner, and each measure does not possess an equal level of importance to the index concerned. However, the use of the multiple measures significantly increases the accuracy and transparency of the evaluation of each index.

Chapter 2: Australia

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
Federal renewable electricity generation incentives have complementary state-level FITs to promote micro-generation at households and businesses in some states.	**2/5**

2. Power Market Opportunities Index	Value
An increase in power demand is expected, while nuclear is not thought to be an option to meet it.	**3/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind
Emerging Technologies Technologies that have growth potential in the country.	Solar power, Marine energy

Risk Indices

4. Political Will Risk Index	Value
A political change could lead to the nuclear option for greenhouse gas emissions reduction.	**1/5**

5. Grid Connection Risk Index	Value
Grid connection can be both difficult and expensive for renewable power generators.	**3/5**

6. Planning Permission Risk Index	Value
Remoteness of renewable power installations including onshore wind power makes them immune to significant local opposition.	**0/5**

2.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets*.	1	**2/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	1	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity*.	0	

2.1.1 Operating Incentives

2.1.1.1 Tradable Green Certificates

Australia currently operates a tradable green certificate (TGC) programme at the federal level as well as numerous incentive schemes administered by its states and territories. The key legislation is the Renewable Energy Act 2000, which places an obligation on wholesale electricity purchasers to proportionately contribute towards the annual generation of a target amount of additional renewable electricity (the Renewable Energy Target or RET) through their participation in market trading in Renewable Energy Certificates (RECs).

Renewable electricity producers receive one REC for every MWh of electricity generated under the above-mentioned scheme. The Office of the Renewable Energy Regulator (ORER) accredits and validates certificates created for the generation of eligible electricity. Wholesale purchasers of electricity are then required to acquire and annually surrender certificates equivalent to a set percentage of their purchases in the previous calendar year—the Renewable Power Percentage (RPP). This quota is set by the ORER and revised on a yearly basis according to a formula designed to ensure a target amount of renewable electricity generation (in GWh) is reached (see Table 2.1). For example, based on the government's generation target, the RPP is 5.98 per cent in 2010. Therefore, a liable party purchasing 100,000 MWh of electricity in 2010 would have to surrender 5,980 RECs to fully discharge their liability for that year.

Eligible generation sources for REC creation include:

- Renewable power stations such as wind, small hydro, landfill gas, solar and bagasse
- Owners and agents of solar water heaters and small generation units
- Existing waste coal-mine gas power stations.

Table 2.1: The yearly Renewable Electricity Target in Australia

Calendar year	Renewable power generation in GWh
2010	12,500
2011	10,400
2012	12,300
2013	14,200
2014	16,100
2015	18,000
2016	22,600
2017	27,200
2018	31,800
2019	36,400
2021-2030	41,000

Source: Department of Climate Change, 2010'Renewable Energy Target Factsheet. Available at <www.climatechange.gov.au/government/initiatives/~/media/publications/renewable-energy/enhanced-ret-fs-pdf.ashx>.

The penalty for failing to supply sufficient RECs to discharge a company's quota obligation is currently set at AUD 65 (EUR 43.7[1]) per missing certificate.

Support in meeting the quota is available for companies which engage in areas considered to be emissions-intensive trade exposed (EITE). This is a provision which was introduced to allay fears that imposing green levies on exporters could shift production to countries with less onerous regulations, adversely affecting the Australian economy whilst having little or no impact on global emissions. Eligibility for EITE status is based on an emissions intensity and a trade exposure test which assesses the level of emissions per million dollars of value-added revenue and the difficulties faced by the company in increasing the costs of their products due to international competition. Free RECs are awarded at two levels depending on the outcome of this test, with highly emissions-intensive firms receiving 94.5 per cent aid in meeting their quota, and moderately emissions-intensive firms receiving 66 per cent. Both rates are scheduled to decrease at a rate of 1.3 per cent per annum, starting in 2012.[2]

2.1.1.2 The Solar Credits Scheme

The Solar Credits Scheme was introduced in 2009 to assist in achieving the RET more rapidly. Despite the name, the Solar Credits Scheme includes solar PV, small wind and micro-hydropower. Key eligibility requirements for the Solar Credits Programme include:

- A maximum size of 100 kW for solar PV, 10 kW for wind power, and 6.4 kW for micro-hydropower
- The system must be installed at residential or small commercial premises
- The system must be a new and complete unit. They must have been installed no more than 12 months prior to the date of application for Solar Credits
- The incentive is not applicable to projects that are receiving funding from the Solar Homes and Communities Plan, the Renewable Remote Power Generation Program (RRPGP), or the National Solar Schools Program (NSSP)
- No more than one system at an eligible premises (address)
- Solar Credits may be created only once for a particular installation, irrespective of whether the certificates are created for a 1-year, 5-year or 15-year deeming period.

[1] The AUD-EUR conversion rate used is AUD 1 = EUR 0.672 (the average over the first six months of 2010).
[2] Ministry of Climate Change, EITE Industry Assistance. Available at <www.climatechange.gov.au/government/initiatives/cprs/eite.aspx>.

The Solar Credit Scheme incentivises small-scale generation of renewable power by applying a multiplier of 5 to the amount of RECs created by the generation of 1 MWh of renewable electricity. Therefore, for each MWh generation, 5 RECs will be issued.[3] This multiplier will gradually be reduced until it is phased out altogether in 2015-16 (see Table 2.2).

Table 2.2: The multiplier rates for RECs received by micro-generation systems between 2009 and 2015

Year	9 June 2009 – 30 June 2010	2010 - 2011	2011 - 2012	2012 - 2013	2013 - 2014	2014 - 2015	2015 – 2016 onwards
Multiplier	5	5	5	4	3	2	1 (No multiplier)

Source: The Parliament of the Commonwealth of Australia, *Renewable Energy (Electricity) Amendment Bill 2009*. Available at <www.climatechange.gov.au/renewabletarget/publications/pubs/renewable_energy_electricity_amendment_bill_2009.pdf>.

2.1.1.3 Price of RECs

The price of RECs is not regulated but rather determined by supply and demand with a ceiling implied by the regulator's penalty shortfall fee of AUD 65 per certificate. On the spot market, RECs were worth between AUD 27 and AUD 42 (EUR 16.2 and 25.2) in the period 1 December 2002 to 31 January 2007, with an average of approximately AUD 31 (EUR 18).[4]

In October 2009, the price plunged to a low of AUD 23 (EUR 15.46)—representing a fall of 54 per cent relative to its level four months earlier.[5] The surge in REC creation caused by the Solar Credits scheme was widely cited as the reason behind the oversupply and consequent collapse in the price of RECs. This has led to the decision by the federal government to develop a new framework. Table 2.3 shows the government estimates for the total compensation to renewable power generators in 2010.

Table 2.3: Estimated generation compensation of renewable power in Australia in 2010

Region	Estimated average regional price of electricity in 2010 (AUD/MWh)[b]	Estimated REC spot price in 2010 (AUD)[b]	Estimated total compensation[a] per MWh	
			AUD	EUR
Queensland	34.9	31	65.9	44.3
New South Wales	40	31	71	47.7
South Australia	52.2	31	83.3	56.0
Victoria	43	31	74.1	49.8
Tasmania	60.5	31	91.5	61.5

Notes: These figures exclude potentially applicable state-level incentive payments.
[a] Assumes a rate of REC generation of 1 REC per MWh. This will be higher in the case of small-scale solar PV.
[b]The average spot market price in 2009 prices with a 2.5 per cent inflation rate was used in estimate.
Source: ABARE, Energy in Australia 2010. Available at <www.abare.gov.au/publications_html/energy/energy_10/energyAUS2010.pdf>.

[3] Department of Climate Change and Energy Efficiency 2010. Available at <www.climatechange.gov.au/government/initiatives/renewable-target.aspx>.
[4] McLennan Magasanik Associates, Review of REC Market, October 2007. Available at <www.orer.gov.au/publications/pubs/modelling-2007.pdf>.
[5] Department of Climate Change and Energy Efficiency 2010. Available at <www.climatechange.gov.au/government/initiatives/renewable-target.aspx>.

2.1.1.4 Changes to the RET in Australia in 2011

Starting from 1 January 2011 the existing federal RET scheme will be separated into two schemes—the Large-scale Renewable Energy Target (LRET) for large scale projects and the Small-scale Renewable Energy Scheme (SRES) for small-scale projects. The schemes will create different certificates—called LRECs and SRECs, respectively. The changes to the RET are given below.

The Small-scale Renewable Energy Scheme (SRES)
A separate market for TGCs deriving from small-scale generation—SRECs—will be created and from the start of 2011, the following facilities will be deemed eligible to create SRECs:

- Micro-generators for the following:
    - Wind power: Capacity under 10 kW and annual generation under 25 MWh
    - Solar PV: Capacity under 100 kW and annual generation under 250 MWh
    - Small hydro: Annual generation under 25 MWh
- Solar thermal installations—which can receive SRECs for the amount of electricity displaced by their use
- Waste coal mine gas (WCMG) power stations.

The demand for SRECs is to be created by the imposition of a quota called the Small-scale Technology Percentage (STP) which will be decoupled from, and not count towards, the RPP. A decision on the size of this quota is expected in the second half of 2010. Small-scale generators will sell their SRECs directly to the regulator, ORER, for a fixed price of AUD 40 (EUR 26.9), which is inclusive of sales tax.[6]

The Large-scale Renewable Energy Target (LRET)
The LRET will work in an essentially identical manner to the RET scheme which preceded it. The previous annual renewable electricity targets which applied to the RET will have been reduced to take into consideration the contribution that the SRES will make towards achieving the overall target. As was previously the case, one Large-scale Renewable Energy Certificates (LREC) will be awarded per MWh of large-scale renewable power generated.[7]

The penalty rate for incurring a shortfall in this target will be AUD 65[8] (EUR 43.70), as in the RET scheme. Exemptions of up to 90 per cent of usage above 9,500 GWh will be available to firms which qualify for emissions-intensive, trade-exposed (EITE) status.

Estimated total compensation per MWh of renewable electricity generated in 2011 from the SRES and LRET scheme is given in Tables 2.4 and 2.5. It consists of an estimate for the price of the TGCs generated by the plant (SREC or LREC), plus an estimate for the volume-weighted average annual price of electricity, expressed in AUD/MWh.

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[6] ORER, Renewable Energy Certificates. Available at <www.orer.gov.au/recs/index.html>.
[7] ORER, MRET Overview, February 2008. Available at <www.orer.gov.au/publications/pubs/mret-overview-feb08.pdf>.
[8] Ministry of Climate Change, Enhancing the Renewable Energy Target. Available at <www.climatechange.gov.au/government/initiatives/~/media/publications/renewable-energy/enhancing-ret-discussion-paper-pdf.ashx>.

Table 2.4: Estimated generation compensation of small-scale renewable power in Australia from 1 January 2011

Region	Estimated average regional price of electricity in 2011 (AUD/MWh)[b]	Estimated SREC price in 2011 (AUD)[b]	Estimated total compensation[a] per MWh	
			AUD	EUR
Queensland	35.7	40	75.7	50.8
New South Wales	41	40	81	54.4
South Australia	53.6	40	93.6	62.9
Victoria	44.1	40	84.1	56.5
Tasmania	62	40	102	68.5

Notes: These figures exclude potentially applicable state-level incentive payments.
[a] Assumes a rate of REC generation of 1 REC per MWh. This will be higher in the case of small-scale solar PV.
[b] The average spot market price between 2002-2007 was used. 2009 prices and a 2.5 per cent inflation rate were used in estimate.
Source: ABARE, Energy in Australia 2010. Available at <www.abare.gov.au/publications_html/energy/energy_10/energyAUS2010.pdf>.

Table 2.5: Estimated generation compensation of large-scale renewable power in Australia from 1 January 2011

Region	Estimated average regional price of electricity in 2011 (AUD/MWh)[a]	Estimated LREC price in 2011 (AUD)[a]	Estimated total compensation[a] per MWh	
			AUD	EUR
Queensland	35.7	31	66.7	44.8
New South Wales	41	31	72	48.4
South Australia	53.6	31	84.6	56.9
Victoria	44.1	31	75.1	50.5
Tasmania	62	31	93	62.5

Notes: These figures exclude potentially applicable state-level incentive payments.
[a] The average spot market price between 2002-2007 was used. 2009 prices and a 2.5 per cent inflation rate were used in estimate.
Source: ABARE, Energy in Australia 2010. Available at <www.abare.gov.au/publications_html/energy/energy_10/energyAUS2010.pdf>.

2.1.1.5 State-level Operating Incentives

2.1.1.5.1 Australian Capital Territory

The Australian Capital Territory has operated a FIT scheme since 1 March 2009 for solar and wind power up to 30 kW. Households and small businesses with new or existing solar PV or wind power installations are eligible, while other technologies may be included in the future. Between 1 March 2009 and 30 June 2010, a FIT rate of 500.5 AUD/MWh (336 EUR/MWh) will be paid to systems up to 10 kW.

For systems between 10 kW and 30 kW, a rate of 400.4 AUD/MWh (269 EUR/MWh) will be paid. The FIT rate for new projects is set each year. When a generator enters into a purchase agreement with a supplier, the generator is guaranteed the FIT rate existing at that time for the full 20 years of the agreement. Operators of renewable projects in the Australian Capital Territory can take advantage of both the state and the federal RET schemes. The rates are paid for power consumed onsite as well as power fed to the grid.[9]

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[9] Australian Capital Territory Feed-In Tariff Factsheet. Available at <www.environment.act.gov.au/__data/assets/pdf_file/0005/144608/FiTFactSheet.pdf>.

2.1.1.5.2 New South Wales

In June 2009, the New South Wales government announced the introduction of a new FIT for wind and solar power up to 10 kW. Only customers whose annual consumption is less than 160 MWh can apply. The scheme guarantees a FIT rate of 600 AUD/MWh (403.7 EUR/MWh) for electricity generated and used onsite or fed into the grid. The costs of the scheme are retrieved through a levy placed on power distributors who will pass costs to all New South Wales electricity customers.[10] Operators of renewable projects in New South Wales can take advantage of both the state and the federal RET schemes. The scheme commenced on 1 January 2010 and will operate for seven years, subject to ongoing reviews. The first of these reviews is scheduled for 2012 or when the installed capacity of renewable energy reaches 50 MW—whichever occurs sooner.[11]

2.1.1.5.3 Queensland

Queensland began operation of a FIT system known as the Solar Bonus Scheme on 1 July 2008. The FIT applies only to small-scale solar PV generators of less than 10 kW of installed capacity for single-phase power, and 30 kW for three-phase power. Only customers whose own yearly consumption does not surpass 100 MWh of electricity may apply to receive the FIT tariff (this roughly translates to an annual electricity bill of AUD 19,000 or EUR 12,786).

The rates are only paid for power fed into the grid. Similar to other state-level FITs, Queenland's FIT system offers a rate of 440 AUD/MWh (296 EUR/MWh) for surplus electricity fed into the grid. The FIT will be offered until 2028 to customers who sign up to the scheme prior to 2018, or when a capacity cap of 8 MW is reached, whichever occurs first.[12] Operators of renewable projects in Queensland can take advantage of both state and federal (RET) incentive schemes.

2.1.1.5.4 South Australia

The state government of South Australia implemented a FIT scheme for solar PV systems up to 10 kW on 1 July 2008, which will operate until June 2028. Only customers whose own annual consumption does not surpass 160 MWh of electricity may apply (this roughly is equivalent to an annual electricity bill of AUD 30,000 or EUR 20,190).

The scheme guarantees a FIT rate of 440 AUD/MWh (296 EUR/MWh) for electricity fed into the grid, which is twice the household retail rate of electricity. The rates are only paid for power fed into the grid and not for power consumed onsite. In May 2009, a review began after the scheme reached its 10 MW capacity cap. The results of the review, and a decision as to whether the FIT should be expanded, are expected in the second half of 2010.[13] Operators

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[10] NSW Department of Water and Energy, NSW Solar Bonus Scheme. Available at <www.dwe.nsw.gov.au/energy/sustain_renew_fit_faq.shtml>.
[11] NSW Government, Solar Bonus Scheme. Available at <www.industry.nsw.gov.au/energy/sustainable/renewable/solar/solar-scheme>.
[12] Queensland Office of Clean Energy, Solar Bonus Scheme, July 2009. Available at <www.cleanenergy.qld.gov.au>.
[13] Government of South Australia, South Australia's Solar Feed-in Scheme. Available at <www.climatechange.sa.gov.au/index.php?page=feed-in-scheme>.

of renewable projects in South Australia can take advantage of both state and federal (RET) incentive schemes.[14]

2.1.1.5.5 Tasmania

In December 2009, the Tasmanian government announced their intent to introduce a FIT system in their energy policy statement. However, deliberations concerning the generosity of the tariff concluded that there would be no subsidy to customers wishing to feed renewable electricity back into the grid. The tariff is thus the same as the household retail tariff, or 193 AUD/MWh (130 EUR/MWh).[15]

2.1.1.5.6 Victoria

The State of Victoria also operates two FIT systems for microgeneration: a standard FIT and a premium FIT. Operators of renewable projects in Victoria can take advantage of both state and the federal RET schemes.

The standard FIT was established in 2004 for wind power generation of less than 100 kW. Since 2007 it has also covered wind, solar, hydro and biomass of less than 100 kW. The scheme mandates electricity suppliers with more than 5,000 customers to purchase the excess electricity generated by microgenerators and supplied to the power grid, and to publish the FIT rate they offer with the government. The rate may vary among suppliers, while the legislation ensures that microgenerators are offered a ‘fair and reasonable price’.[16] The rate offered to micro-generators may be referred to the Essential Services Commission if it is not thought to be fair and reasonable. The standard FIT does not have a time limit and is considered ongoing.

The premium FIT is in place for solar PV systems in households, community organisations and small businesses with energy consumption of less than 100 MWh a year. Both new and existing solar PV systems up to 5 kW in capacity are eligible to receive a tariff rate of at least 600 AUD/MWh (403.7 EUR/MWh) for electricity that is fed into the power grid until 2024.[17] For both FIT systems, the rates are only paid for power fed into the grid.

2.1.1.5.7 Western Australia

A new FIT system is due to come into force on 1 August 2010,[18] offering a tariff rate of 400 AUD/MWh (269 EUR/MWh) for surplus electricity fed into the grid. Solar PV, wind and micro-hydropower up to 5 kW (for Synergy residential customers) or 30 kW (for Horizon Power residential customers) are eligible. The FIT will be renewed on a three-year rolling basis subject to reviews which will based on the state government’s perception of the renewable energy sector’s need for support.

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[14] The Parliament of South Australia, Electricity (Feed-In Scheme – Solar Systems) Amendment Act 2008. Available at <www.legislation.sa.gov.au>.
[15] Government of Tasmania, Energy Policy Statement. Available at <www.dier.tas.gov.au/__data/assets/pdf_file/0005/47246/Energy_Policy_Statement.pdf>.
[16] For further information on a “fair price” see the DPI website. Available at <www.dpi.vic.gov.au/DPI/dpinenergy.nsf/LinkView/0D6A69DB0F82172ACA257456001BCF464CAC723B1D538D66CA25740C000D2004/$file/Feed-in Tariff Fair and Reasonable Criteria.pdf>.
[17] Department of Primary Industries, Feed-in Tariffs in Victoria, July 2009. Available at <www.dpi.vic.gov.au>.
[18] Sustainable Energy Development Office, A Feed-in Tariff for Renewable Energy Systems. Available at <www.sedo.wa.gov.au/pages/re_feed-in_tariff.asp>.

The rates are only paid for power fed into the grid.[19] Once enrolled in the scheme, however, the FIT rates for existing customers are guaranteed for 10 years. Operators of renewable projects in Western Australia can take advantage of both the state incentives and the federal RET scheme.

2.1.2 Investment Support

The Australian government has announced an AUD 652 million (EUR 438.7 million) Renewable Energy Future Fund (REFF) in its 2010/11 budget,[20] which is intended to provide support for renewable energy projects of all sizes, with particular emphasis on wind, solar and biomass projects. The fund will provide support through partnerships between the government and the private sector to make critical, early-stage investments to attract private funding in order to support the commercialisation of renewable technologies. Details of the specific commitments for the fund are expected in late 2010. Various small-scale state investment support programmes exist at the state level as well.

The governments Clean Energy Initiative was launched in 2009. As part of the programme, a total of AUD 1.6 billion has been allocated to the Solar Flagships program up to 2015/16, which will support up to 1,000 MW of solar power (solar PV and concentrated solar-thermal power, CSP). It is envisaged that four projects will be supported, two solar PV and two CSP. In stage one of the program, eight projects—four solar PV and four CSP—have entered bids. A decision on the successful applicants is expected in 2011.[21]

In 2008, the government launched the Geothermal Drilling Program, which provides assistance to companies seeking to develop geothermal energy with the proof-of-concept projects. The program has AUD 50 million in available funding. In December 2009, five companies were given grants totalling AUD 7 million to conduct test drilling and feasibility studies for geothermal development. [22]

[19] Western Australia, Feed-in Tariff. Available at <www.clean.energy.wa.gov.au/pages/re_feed-in_tariff.asp>.
[20] Australian Government Budget 2010-11 Budget Summary. Available at <www.budget.gov.au/2010-11/content/at_a_glance/html/at_a_glance.htm>.
[21] Ministry of Resources, Clean Energy Initiative. Available at <www.ret.gov.au/Department/Documents/CEI Fact Sheet (13 May 09).pdf>.
[22] Department of Resources, Energy and Tourism, Geothermal Drilling Program. Available at <www.ret.gov.au/energy/energy programs/RenewableEnergyFund/Geothermal_drilling_program/Pages/GeothermalDrillingProgram.aspx>.

2.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**3/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	0	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants*.	1	

2.2.1 Energy Consumption

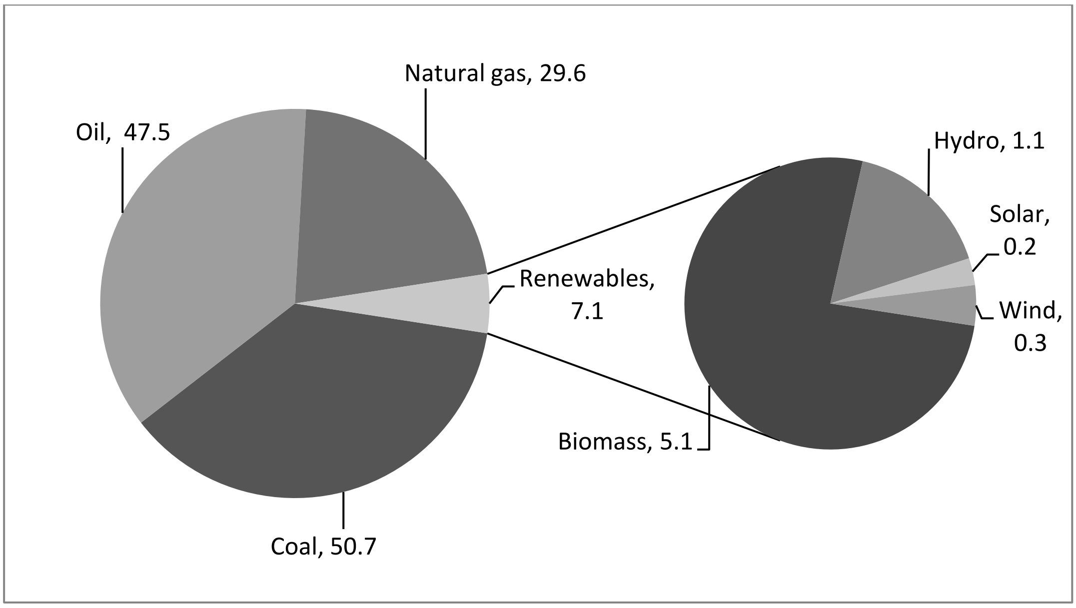
Primary energy consumption in Australia was 137.9 million tonnes of oil equivalent (Mtoe) in 2007/08, representing a 1.5 per cent increase from 2006-07. In the 10 years prior to 2007/08, primary energy consumption had an annual growth rate of 1.9 per cent. Oil and coal together account for approximately three-quarters of primary energy consumption (see Figure 2.1). Though Australia is a net importer of crude oil, it is one of the world's largest energy exporters, primarily coal due to its large reserves.

The *Australian Bureau of Agricultural and Resource Economics* (ABARE), a government research institute, projects that primary energy consumption will grow at an average rate of 1.4 per cent a year between 2007-08 and 2029-30, to reach 184.3 Mtoe by 2029/2030. Renewables are projected to account for 7.6 per cent of consumption by 2029/2030.[23]

Final energy consumption in Australia in 2007/08 was 89.2 Mtoe. In the 10 years prior to 2007/08, final energy consumption had an average annual growth rate of 2 per cent. From 2008/08 to 2029/30, final energy consumption in Australia is projected to increase at a compound annual growth rate (CAGR) of 1.9 per cent to 119.9 Mtoe.[24]

[23] ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.
[24] ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.

Figure 2.1: Primary energy consumption in Australia in 2007/08 (Mtoe): Total 137.9 Mtoe



Source: ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.

2.2.2 Electricity Sector

In 2008/09, winter peak demand in the National Electricity Market (NEM)[25] reached 34,422 MW on 28 July, and national summer peak demand reached 35,551 MW on 29 January. This represents an increase of 4 per cent and 11 per cent, respectively, from the previous year.[26] The Australian Energy Regulator anticipates that the peak demand in 2012/2013 will reach approximately 38,000 MW.[27]

Australia's total installed generating capacity was 50.5 GW in 2007/08 (see Figure 2.2). Generating capacity increased at a CAGR of 2.2 per cent between 2003/04 and 2007/08.[28] Two thirds of generating capacity is owned by state or local governments.[29] At the end of April 2010, there were 15 committed power development projects in Australia with a combined capacity of 2,687 MW totalling AUD 4.9 billion. Non-renewable power plants represented six of the 15 projects, or 1,667 MW, under development, half of which were natural gas-fired projects. The renewable power projects over 30 MW that were under development as of April 2010 were all wind power.[30]

A total of 265.2 TWh of electricity was generated in Australia in 2007/08, up from 254.8 TWh in 2006/07. Three-quarters of the generation is based on coal, which reflects the large

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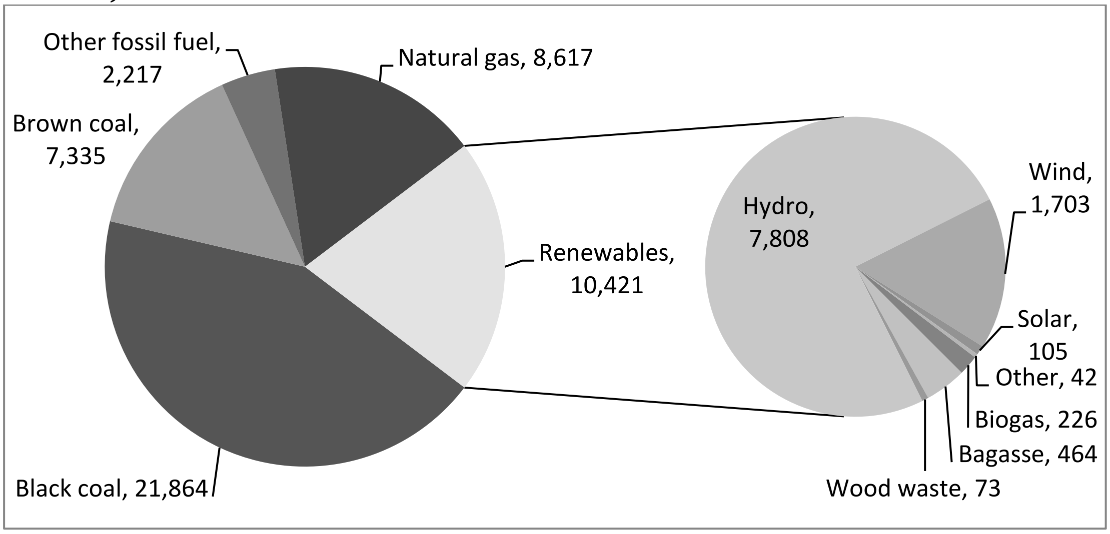
[25] The National Electricity Market does not include Western Australia and the Northern Territories. Due to distance from other markets, these states have an independent power system and are not connected to other markets.
[26] Australian Energy Regulator, Electricity Market Reports – Long-term Analysis. Available at <www.aer.gov.au/content/index.phtml/tag/MarketSnapshotLongTermAnalysis/fromItemId/722740>.
[27] Australian Energy Regulator, State of the Energy Market 2008. Available at <www.aer.gov.au>.
[28] ABARE, Energy in Australia 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energyAUS2010.pdf>.
[29] AER, State of the Energy Market 2009. Available at <www.aer.gov.au>.
[30] ABARE, Major Development Projects – April 2010 Listing. Available at <www.abareconomics.com>.

coal reserves situated along the eastern coastline where the bulk of electricity is both produced and consumed (see Figure 2.3). A total of 7 per cent of electricity generation came from renewable energy sources.[31]

Figure 2.2: Total installed generating capacity in Australia in 2008/09 (MW): Total 50,454 MW



Source: Abare, Energy in Australia 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energyAUS2010.pdf>.

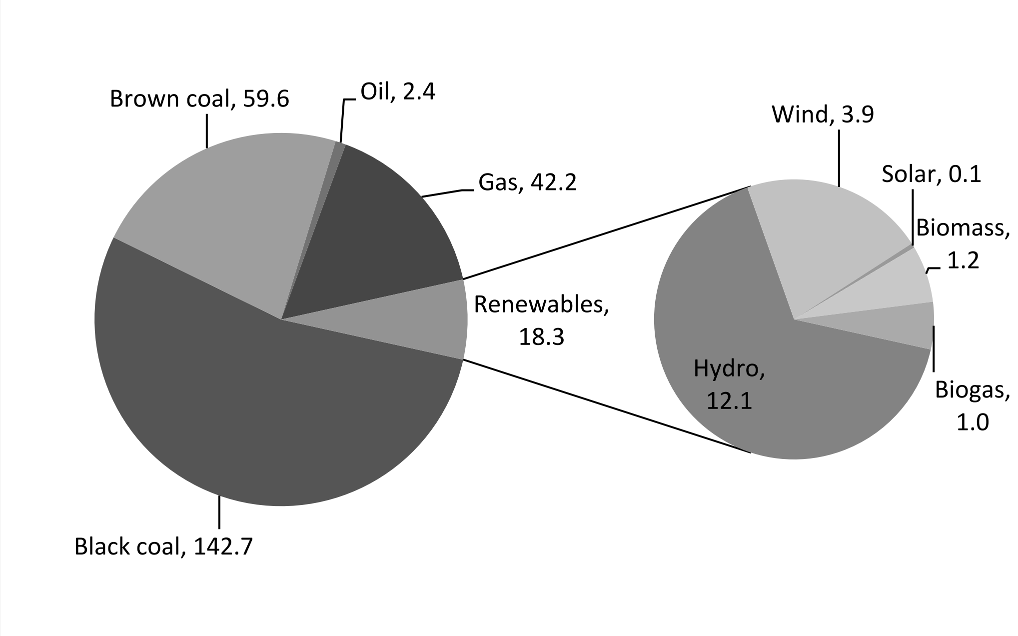
ABARE projects that gross electricity generation will increase at an average annual rate of 1.8 per cent between 2007/08 and 2029/30 to reach 366 TWh, just under half of which will come from coal (see Figure 2.4). Renewable power generation is expected to increase to 69 TWh, an average annual growth rate of 6.4 per cent between 2007/08 and 2029/30, and contribute to 19 per cent of total generation.[32] It is worth noting that the ABARE projection for 2029/30 is larger than the government's target for 60,000 GWh of renewable electricity production by 2020.

2.2.3 Nuclear Power

In May 2006, the previous Australian coalition government led by John Howard called for a debate over the establishment of a nuclear power industry in Australia. In the following year, the government announced that they will support the development of nuclear power in Australia. This would include the establishment of a nuclear regulatory regime and the removal of regulatory obstructions that may hamper the construction of nuclear power plants. However, the November 2007 federal elections saw the Labour Party win a majority in parliament, and following the August 2010 elections the Labour Party once again formed the government. The Labour Party are opposed to the development of nuclear power plants in Australia.[33]

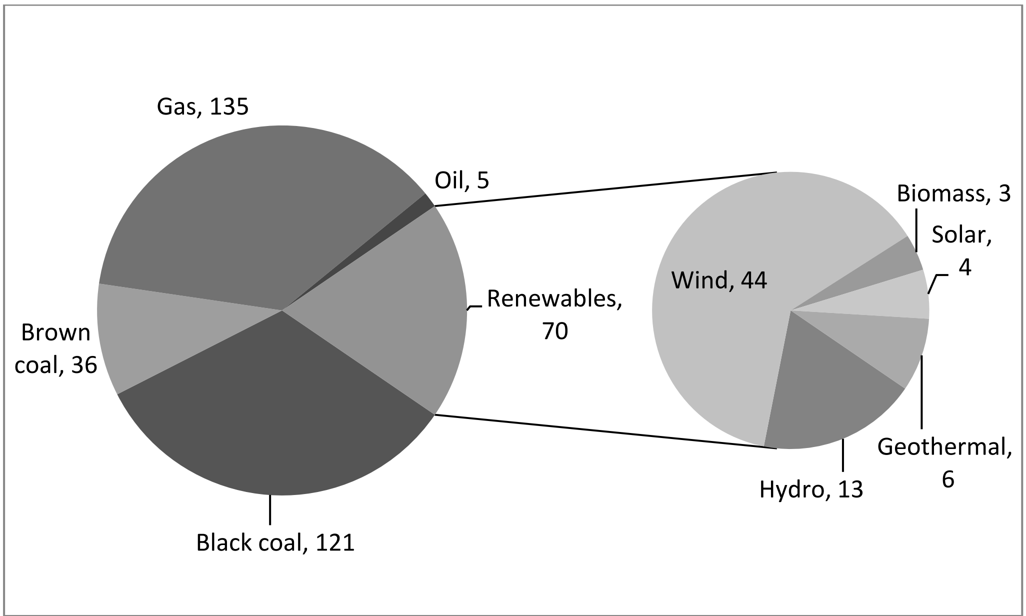
[31] Abare, Energy in Australia 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energyAUS2010.pdf>.
[32] ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.
[33] Labor rejects nuclear power in Australia, Sydney Morning Herald, 17 February 2010. Available at <news.smh.com.au/breaking-news-national/labor-rejects-nuclear-power-in-australia-20100217-ocdu.html>.

Figure 2.3: Electricity generation mix in Australia in 2007/08 (TWh): Total 265.2TWh



Source: ABARE, Energy in Australia 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energyAUS2010.pdf>.

Figure 2.4: Projected electricity generation mix in Australia in 2029/30 (TWh): Total 366 TWh



Source: ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.

2.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Onshore wind
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar power, Marine energy

2.3.1 Renewable Electricity Generation

The Australian government has a target of 20 per cent of the country's electricity supply to come from renewable energy sources by 2020. In 2009, hydropower represented 75 per cent of installed renewable power generating capacity in Australia, followed by wind power (see Table 2.6). From 2004 to 2009, wind power experienced the fastest growth rate among all the renewable power technologies.

Table 2.6: Total installed capacity of renewable electricity generation in Australia from 2004 to 2009 (MW)

Source	2004	2005	2006	2007	2009	CAGR 2004-2009 (%)
Biogas	185	130	175	218	226	4.1
Biomass[a]	502	487	535	453	578	2.9
Hydro	7,795	7,571	7,827	7,814	7,808	0.03
Wind	740	637	818	1,249	1,703	18.1
Solar	0	2	71	71	105	169.2[c]
Other[b]	0	0.6	0.7	1	1	13.6[c]
TOTAL	9,222	8,828	9,427	9,805	10,421	2.5

Note: [a] Biomass includes wood-waste and bagasse (the fibrous residue of the sugar cane milling process); [b] Ocean wave, tidal and geothermal; [c] CAGR calculated from 2005.
2008 figures are not available.
Source: ABARE, *Energy in Australia 2005-20010*. All available at <www.abareconomics.com>.

2.3.2 Resource Potential

Predictably, the potential for solar power development is very high in Australia. Much of the country has a solar irradiation level of above 2,129 kWh/m^2 a year. Tasmania has the lowest level at approximately 1,115 kWh/m^2, although this is equivalent to the levels of southern Germany and the UK. In a study of offshore wind resources in Australia, Western Australia was identified as having the best resources.[34]

Much of the coastal regions throughout the west, south and southeast of the country have wind speeds of approximately 7.76-10.11 m/s. However, the authors of the study did not think that developing offshore wind power was suitable for Australia given the abundance of

[34] Denise Rice, WA Has Best Offshore Wind Site, ScienceAlert, 16 May 2008. Available at <www.sciencealert.com.au/news/20081605-17335.html>.

land available for onshore wind power developments and higher costs of development. Australia also has excellent wave and tidal resources, with potential of over 160 kW/m of wave crests in exposed regions off the south-western tip of the country. In addition, much of the southern coastline has a wave potential of above 100 kW/m of wave crest.[35] A report commissioned by the Australian Geothermal Energy Association suggests that geothermal sources could provide up to 2 GW of baseload capacity by 2020.[36] The Australian Clean Energy Council calculates that there is a potential for 1,845 MW of biomass capacity by 2020 producing over 10.5 GWh hours of renewable electricity annually.[37]

2.3.3 Levelised Generation Costs

Under the RET TGC system, the total generation compensation received by a renewable power plant comprises the wholesale market price of electricity and the income from the sale of the REC (see Table 2.7). In the 2008/09 fiscal year, the average national spot price for electricity on the National Electricity Market (NEM) was 44.83 AUD/MWh. However, there was a significant disparity in the average wholesale market price among states. Queensland had the lowest average annual price at 34 AUD/MWh and Tasmania had the highest at 58.48 AUD/MWh.[38] In Western Australia, the average was 50 AUD/MWh (28.75 EUR/MWh).[39]

Because of a decline in demand for RECs during 2009, the REC spot price declined to AUD 37.80 each as of 3 August 2009[40] and AUD 23 as of 30 October 2009.[41] REC spot prices were stable at approximately AUD 50 until the end of May 2009, at which point prices began to decline steeply.[42] To calculate average generation compensation, the spot price of 3 August 2009, AUD 37.80, is used in Table 1.5. The generation compensation from the sale of the TGCs in 2008 was below the levelised generation cost of all renewable power technologies. Therefore, additional support is essential.

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[35] Department of Environment, Water, Heritage and the Arts, 'Renewable Energy Atlas'. Available from <www.environment.gov.au/apps/boobook/mapservlet?app=rea>.

[36] Department of Resources, Energy and Tourism, Australian Geothermal Industry – Technology Roadmap 2008. Available at <www.ret.gov.au/energy/clean_energy_technologies/energy_technology_framework_and_roadmaps/hydrogen_technology_roadmap/Documents/GEOTHERMAL ROADMAP.pdf>.

[37] The Clean Energy Council, Biomass Resources Appraisal. Available at <cleanenergycouncil.org.au/bioenergy/Biomass Resource Appraisal.pdf>.

[38] Australian Energy Market Operator, Average 'Electricity Price Tables'. Available at <www.aemo.com.au/data/avg_price/averageprice_main.shtml>.

[39] Australian Energy Regulator, State of the Energy Market 2009. Available at <www.accc.gov.au>.

[40] Green Energy Markets, 'Weekly spot certificate prices – week ending 3 August 2009'. Available at <greenmarkets.com.au/images/Certificate price weekly/3 AUG_large.jpg>.

[41] Warwick Johnston, 'Australia Renewable Energy Crisis as REC Prices Drive,' Renewable Energy Focus, 20 October 2009. Available at <www.renewableenergyfocus.com/view/4914/australian-renewable-energy-crisis-as-rec-price-dives/>.

[42] Green Energy Markets, 'Weekly spot certificate prices – week ending 3 August 2009'. Available at <greenmarkets.com.au/images/Certificate price weekly/3 AUG_large.jpg>.

Table 2.7: Comparison of generation compensation in Australia in 2008/09 with levelised generation costs in the OECD

State	Technology	Average wholesale price of electricity 2008/09 (AUD/MWh)[a]	Generation compensation with REC price of AUD 37.80 (AUD/MWh)[b]	Generation compensation in Australia (EUR/MWh)[c]	Levelised generation costs in the OECD (EUR/MWh)[d,e]
New South Wales	Onshore wind	38.85	76.65	44.07	38-111
	Solar PV		76.65	44.07	143-408
	Biomass		76.65	44.07	60
	Biogas		76.65	44.07	65
	CSP		76.65	44.07	92
Queensland	Onshore wind	34	71.8	41.28	38-111
	Solar PV		71.8	41.28	143-408
	Biomass		71.8	41.28	60
	Biogas		71.8	41.28	65
	CSP		71.8	41.28	92
South Australia	Onshore wind	50.98	88.78	51.04	38-111
	Solar PV		88.78	51.04	143-408
	Biomass		88.78	51.04	60
	Biogas		88.78	51.04	65
	CSP		88.78	51.04	92
Tasmania	Onshore wind	58.48	96.28	55.35	38-111
	Solar PV		96.28	55.35	143-408
	Biomass		96.28	55.35	60
	Biogas		96.28	55.35	65
	CSP		96.28	55.35	92
Victoria	Onshore wind	41.82	79.62	45.77	38-111
	Solar PV		79.62	45.77	143-408
	Biomass		79.62	45.77	60
	Biogas		79.62	45.77	65
	CSP		79.62	45.77	92
Western Australia	Onshore wind	50	87.80	50.48	38-111
	Solar PV		87.80	50.48	143-408
	Biomass		87.80	50.48	60
	Biogas		87.80	50.48	65
	CSP		87.80	50.48	92

Note: [b] REC price of AUD 37.80 is used for all figures.
[c]The exchange rate used is the 2008 average: AUD 1 = EUR 0.5749.
[d] Figures based on a 5 per cent discount rate.
Source: [a] Australian Energy Market Operator, Average Electricity Price Tables. Available at <www.aemo.com.au/data/avg_price/averageprice_main.shtml>; Australian Energy Regulator, *State of the Energy Market 2009*. Available at <www.accc.gov.au>.
[e] IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

2.3.4 Wind Power

2.3.4.1 Onshore Wind Power

According to the Australian government's renewable energy production projections for 2029/2030, electricity generation by wind will be 44 TWh, compared to 4 TWh in 2007/08, an average annual growth rate of 11.6 per cent between 2007/08 and 2029/30.[43] Four new projects, totalling 406 MW, were completed in 2009 (see Table 2.8). Wind farms in Australia

43 ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.

are located largely in New South Wales, Tasmania, Queensland and Victoria because of favourable wind conditions in those states. The state of South Australia alone has 40 per cent of total installed wind power capacity (740 MW).[44]

Table 2.8: Growth in installed capacity of wind power in Australia from 2000 to 2009

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	CAGR 2000-09
MW	32	73	105	198	380	708	817	824	1,306	1,712	55.6%

Source: GWEC, Global Wind Report 2009, 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.

By the end of April 2009 there were additional nine projects at an advanced stage of development, totalling 914 MW (see Table 2.9). A further 72 projects, totalling 10,108 MW, were at various stages of the planning process.[45]

Table 2.9: Wind power projects under construction in Australia as of April 2010

Name of wind farm	Developer	Date operational	Capacity	Investment cost (AUD millions
Collgar Wind Farm	UBS IIT/REST	2012	206 MW	750
Crookwell 2	Union Fenosa Wind Australia	2011	92 MW	238
Gunning	Acciona Energy	N/A	47 MW	140
Hallett 4 (North Brown Hill)	Energy Infrastructure Investments	2011	132 MW	341
Hallett 5 (The Bluff)	AGL	2011	52 MW	135-145
Lake Bonney stage 3	Infigen Energy	2010	39 MW	N/A
Musselroe	Roaring 40s	2012	168 MW	425
Oaklands Wind Farm	AGL/ Windlab Systems	2011	67 MW	200
Waterloo stage 1	Roaring 40s	2010	111 MW	300

Source: ABARE, Electricity Generation: Major Development Projects April 2010. Available at <www.abareconomics.com>.

The largest operational wind farm in Australia is the 192-MW Waubura Wind Farm in Victoria. Completed in July 2009, the wind farm was developed by the Australian subsidiary of Spain’s Acciona Energy. An Australian engineering company, Keppel Prince Engineering, received the AUD 50-million contract for the supply and erection of the towers. Acciona 1.5 MW turbines were used for the project. A long-term purchase power agreement was concluded between Acciona and Origin Energy, a local energy supplier.[46]

The largest wind power project under construction is the Collgar Wind Farm, which is being developed by UBS International Infrastructure Fund and the Retail Employees Superannuation Trust in Western Australia. Construction began in June 2010, and the 206-MW wind farm, which will consist of 111 2-MW turbines, is expected to be completed in April 2012.[47] The Silvertown Wind Farm is the largest wind farm planned in Australia. The wind farm, to be located in New South Wales, is being developed by Macquarie Capital Group Ltd., the German renewable energy developer Epuron, and the Portuguese developer

[44] GWEC, Global Wind Report 2009, 2010. Available at <www.gwec.net >.
[45] ABARE, Electricity Generation: Major Development Projects April 2010. Available at <www.abareconomics.com>.
[46] For more information see the Waubura Wind Farm website at <www.waubrawindfarm.com.au>.
[47] For more information see the Collgar Wind Farm website at <www.collgarwindfarm.com.au>.

Martifer Renewables, and is planned to have a capacity of 1 GW. The first phase of the AUD 2.2 billion was approved by the government in May 2010 and construction is scheduled to begin in 2011.[48]

2.3.4.2 Offshore Wind Power

As of September 2010, there were no offshore wind power plants in operation or development in Australia.

2.3.5 Biomass

2.3.5.1 Solid Biomass

The Clean Energy Council's Bioenergy Roadmap states that there are sufficient biomass resources to supply a large proportion of Australia's future energy production. However, the industry is currently largely fragmented and has yet to gain the support of financial investors on a large scale. The share of biomass power in the total generating capacity mix has declined as other sources, particularly onshore wind power, have grown. It is thought that waste wood and sugarcane can together provide 6,113 GWh of renewable electricity by 2020, whereas the long-term growth prospect for agricultural-related wastes is also significant. Agricultural waste is projected to provide 50.5 TWh of electricity generation by 2050.[49] In 2007-8, all forms of solid biomass generated 2 TWh of electricity.[50]

The primary feedstocks for solid biomass are bagasse and wood waste. Bagasse-powered plants are generally located in Queensland where most of the sugar production plants in Australia are located. Table 2.10 shows the installed generating capacity of solid biomass power plants in Australia as of the end of 2009.

As of April 2009 there was one biomass power project over 30 MW under development, the 180-MW Belly Bay Power Plant in Tasmania. The developers, however, have suspended work on the project.[51] A number of projects under 30 MW are also in development. There are substantial unused stocks of agricultural residues and solid waste streams that have the potential for use in biomass-fuelled power generation (see Table 2.11).[52]

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[48] For more information see the Silverton Wind Farm's website at <www.silvertonwindfarm.com.au/silverton/project/status.htm>.
[49] The Clean Energy Council, Australian Bioenergy Roadmap, September 2008. Available at <cleanenergycouncil.org.au/bioenergy/CEC_Bioenergy_Roadmap.pdf>.
[50] ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.
[51] ABARE, Electricity Generation: Major Development Projects April 2010. Available at <www.abareconomics.com>.
[52] ABARE, Bioenergy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

Table 2.10: Generating capacity of solid biomass power plants in Australia at the end of 2009 by state and territory

State	Bagasse (MW)	Wood waste (MW)	Other (MW)	Total (MW)
New South Wales	81	42	3	126
Victoria	0	0	34	34
Queensland	377	15	4	396
South Australia	0	10	0	10
Western Australia	6	6	63	75
Tasmania	0	0	0	0
Northern Territory	0	0	0	0
Total	464	73	104	641

Source: ABARE, Bioenergy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

Table 2.11: Electricity generation potential for solid biomass in Australia

Description	Quantity (2005/06)	Conversion technique	Electricity generation (GWh/year)		
			2010	2020	2050
Agricultural-related waste					
Nut shells	N/A	Direct combustion	1	1	1
Grain and cotton residue	24 million tonnes	Direct combustion	0	0	47,000
Bagasse	5 million tonnes	Direct combustion	1,200	3,000	4,600
Sugar cane residue	4 million tonnes	Direct combustion, gasification	0	165	3,200
Energy crops					
Oil mallee	N/A	Direct combustion	0	112	484
Camphor laurel	N/A	Direct combustion, gasification	0	83	20
Forest residue					
Native forests	2.2 million tonnes	Direct combustion, pelletising, gasification, and co-firing	75	2,442	4,554
Plantation	3.8 million tonnes				
Sawmill and wood chip residue	2.8 million tonnes				
Pulp and paper mills waste					
Black liquor	N/A	Direct combustion	285	365	365
Wood waste	N/A	Direct combustion	60	85	85
Paper recycling wastes	N/A	Direct combustion	12	48	48
Municipal solid wastes					
Food waste	2.9 million tonnes	Direct combustion	16	141	189
Garden organics	2.3 million tonnes	Gasification	0	37	186
Paper and cardboard	2.3 million tonnes	Direct combustion	0	0	1,548
		Gasification	0	38	191
Wood/timber	1.6 million tonnes	Direct combustion	45	295	1,366

Note: N/A: Not available
Source: ABARE, Bioenergy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

2.3.5.2 Biogas

In 2007/08 biogas generated 1.0 TWh of electricity, primarily landfill and sewage gas.[53] There are currently approximately 54 landfill gas sites in operation throughout Australia with a generation capacity between 1 MW and 50 MW, including at least one in each of the state and territory capital cities.[54] Sewage gas and landfill gas are not subject to the same problem of financial backing noted for biomass.[55] There is significant potential for increasing biogas deployment through the use of anaerobic digestion (AD), particularly with agricultural wastes (see Table 2.12).

Table 2.12: Electricity generation potential for biogas in Australia

Description	Quantity (2005/06)	Conversion technique	Electricity generation (GWh/year)		
			2010	2020	2050
Agricultural-related waste					
Poultry	94 million population	AD	0	90	848
Cattle	870,025 population	AD	0	207	207
Pigs	1.8 million population	AD	1	22	205
Dairy cows	1.4 million population	AD	0	22	89
Abattoirs	1.3 million tonnes	AD	0	337	1,337
Energy crops					
Algae	N/A	AD	N/A	N/A	N/A
Pulp and paper mills waste					
Recycled paper wet waste	N/A	AD	2	8	8
Municipal wastes					
Food waste	2.9 million tonnes	AD	13	126	565
Garden organics	2.3 million tonnes	AD	29	84	275
Landfill gas	9.5 million tonnes	Co-firing, spark-firing	772	1,880	3,420
Sewage gas	735,454 tonnes	AD	57	901	929

Note: N/A: Not available
Source: ABARE, Bioenergy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

Landfill gas has been widely developed in Australia. One project is the Shoalhaven Landfill Gas Project, a 1-MW facility near Sydney in New South Wales. The project was completed in 2002 at a cost of AUD 1.9 million, with an additional AUD 150,000 in government grants. The facility is exacted to be operational until 2017. One of the larger projects in Australia is the 5-MW Eastern Creek Landfill Gas Project in New South Wales. Constructed in 2002 with an initial capacity of 2.5 MW, the installation was expanded to 5 MW in 2004. There is projected to be sufficient landfill gas resources at the site until 2027. Biogas from waste water and sewage treatment is also well developed in Australia. In 1999, Sydney Water installed a 3-MW system at one of their sewage treatment plants at the cost of AUD 5 million. In 2001, Melbourne Water developed a 7.8 MW anaerobic digestion facility at its Werribee sewage and waste water plant. And in 2007, Diamond Energy developed a 1.1-MW digestion facility at the Tatura sewage treatment centre in Victoria.[56]

[53] ABARE, Bioenergy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.
[54] Karen Derkley, Landfill Gas Projects, Swinburne University. Available at <www.swinburne.edu.au/magazine/8/149/profit-forecast-to-fire-up-landfill-gas/>.
[55] The Clean Energy Council, Australian Bioenergy Roadmap, September 2008. Available at <cleanenergycouncil.org.au/bioenergy/CEC_Bioenergy_Roadmap.pdf>.
[56] For details on all these projects see Clean Energy Council, Bioenergy Case Studies. Available at <www.cleanenergycouncil.org.au/cec/resourcecentre/casestudies/Bioenergy/>.

2.3.6 Solar Energy

2.3.6.1 Solar PV

During the early 1990s, Australia held approximately 7 per cent of the global installed capacity of solar PV power. However, despite excellent solar irradiation levels, and the abundance of undeveloped and exposed land, the uptake of solar PV has been slow over the past 10 years and the focus in the country has been on off-grid and residential installations. There was a significant increase in grid-connected solar PV in 2009 (see Table 2.13), with distributed grid-connected capacity (where the output is generally used for a single customer or for a small region, generally small-scale roof-based projects) increasing by over 200 per cent.

There is a long history of off-grid solar PV installations in Australia, supplying electricity to outback and regional communities that are isolated from the power network.[57] One of the largest such projects is the Kings Canyon Solar Power Station in the Northern Territories. The 225-kW project was completed in 2003 at a cost of AUD 2.9 million. The solar power station was designed to reduce the reliance on diesel-fuelled power in the area.[58] Table 2.13 shows the increase in solar PV generating capacity, for both off-grid, distributed grid-connected projects (the output is used at the location or only for local distribution grid) and centralised grid-connected projects (where output is provided to the grid as any other power plant).

Table 2.13: Cumulative installed power of solar PV in Australia from 2000 to 2009 (MW)

Description	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Domestic off-grid	9.11	10.96	12.14	13.59	15.90	18.77	22.14	25.89	30.68	37.87
Non-domestic off-grid	17.17	19.28	23.05	26.75	30.33	34.19	38.40	40.55	42.66	46.04
Grid-connected distributed	2.39	2.80	3.40	4.63	5.41	6.86	9.01	15.04	29.85	97.21
Grid connected centralised	0.54	0.54	0.54	0.66	0.66	0.76	0.76	1.01	1.32	2.53
Total	29.21	33.58	39.13	45.63	52.30	60.58	70.30	82.49	104.51	183.65

Source: IEA-PVPS, National Survey Report of PV Power Applications in Australia 2009, May 2010. Available at < www.iea-pvps.org/countries/download/nsr09/NSR 2009 Australia.pdf>.

One reason given for the large increase in solar PV in 2009 was the declining cost of system prices. For systems up to 5 kW, it is estimated that in 2009 the average system cost was 9 AUD/W, compared to the 12 AUD/W that was the average price from 2004 to 2008. The use of the Solar Credits (which gives bonus RECs to small-scale solar power) and the various states FIT systems have also contributed to increasing deployment. Up until 2009. the federal government's Solar Homes and Communities Plan (SHCP), provided rebates of up to AUD 8,000 for a 1 kW installation on residential buildings and up to 50 per cent of the total system

[57] Clean Energy Council, Clean Energy Fact Sheets – Solar Photovoltaic. Available at <cleanenergycouncil.org.au/info/Solar PV Fact Sheet for ATRAA.pdf>.
[58] Clean Energy Council, Kings Canyon Solar Power Station. Available at <www.cleanenergycouncil.org.au/cec/resourcecentre/casestudies/Solar/Kings-Canyon.html>.

cost for a 2 kW installation on community buildings. The SHCP was ended due to the introduction of the Solar Credits scheme.[59]

TRUenergy, one of Australia's largest energy companies, has proposed a 180-MW solar PV plant near Melbourne, which, if completed, will be the largest solar power station in Australia. The state government has promised support of AUD 100 million towards the project. The project is expected to be completed by 2015.[60]

Large concentrated solar PV power is being developed by the Australian company SolarSystems. The largest such system is under construction in Victoria and is expected to begin operation in 2010, with final construction completed in 2013 by which time it will have a total installed capacity of 154 MW. The total plant is expected to cost AUD 450 million. The federal government has already awarded the project an AUD 75 million grant and the state government has announced an AUD 50 million grant to the company. SolarSystems's heliostat solar PV reflector will be used in the project. In 2005, SolarSystems developed at 720 kW concentrated solar PV system in the Northern Territories to provide power to remote communities. The installation is composed of 30 concentrated solar PV dishes and cost AUD 7 million, part of which was offset from a government grant. The company has also developed a number of demonstration installations around Australia.[61]

The governments Clean Energy Initiative was launched in 2009. Up to 2015/16, a total of AUD 1.6 billion has been allocated to the Solar Flagships program, which will support up to 1,000 MW of solar power (solar PV and concentrated solar-thermal power, CSP). It is envisaged that four projects will be supported, two solar PV and two CSP. In stage one of the program, eight projects – four solar PV and four CSP – have entered bids. A decision on the successful applicants is expected in 2011.[62]

2.3.6.2 Concentrated Solar-thermal Power

There is a large potential for the development of concentrated solar-thermal power (CSP) in Australia. An estimate by the government, which looked only a flat land near demand centres, showed that Australia could every year produce 500 times more energy from CSP than it consumes.[63] As of the end of 2009, there was only one small demonstration CSP plant, a 1.5-MW Fresnel trough, located at the Liddell coal-fired power station in New South Wales (a larger system is being planned at the same location).[64] Construction of a dish Stirling CSP plant began in early 2010 in the town of Whyalla, South Australia. The first phase of the project, which is estimated to cost AUD 15 million, is expected to be completed in February 2011. In subsequent phases, it is expected that 600 dishes will be added, providing a total

[59] IEA-PVPS, National Survey Report of PV Power Applications in Australia 2009, May 2010. Available at < www.iea-pvps.org/countries/download/nsr09/NSR 2009 Australia.pdf>.
[60] Stephen de Tarczynski, Solar Energy Gets a Boost, But Offers Much More, IPS, 4 October 2010. Available at <ipsnews.net/news.asp?idnews=53046>.
[61] Alan Copeland, ABARE, Electricity Generation Major Development Projects – April 2009 Listing. Available at <www.abareconomics.com/publications_html/energy/energy_09/EG09_Apr.pdf>.
[62] Ministry of Resources, Clean Energy Initiative. Available at <www.ret.gov.au/Department/Documents/CEI Fact Sheet (13 May 09).pdf>.
[63] ABARE, Solar Energy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.
[64] Clean Energy Council, Solar Thermal, 2009. Available at <www.cleanenergycouncil.org.au/cec/technologies/solarthermal>.

installed capacity of 130 GW. The implementation of the project began after 12 years of planning and 30 years of research by the Australian National University.[65]

The governments Clean Energy Initiative was launched in 2009. Up to 2015/16, a total of AUD 1.6 billion has been allocated to the Solar Flagships program, which will support up to 1,000 MW of solar power (solar PV and concentrated solar-thermal power, CSP). It is envisaged that four projects will be supported, two solar PV and two CSP. In stage one of the program, eight projects – four solar PV and four CSP – have entered bids. A decision on the successful applicants is expected in 2011.[66]

2.3.7 Small Hydro

The vast majority of hydro capacity is located in New South Wales and Tasmania. From the 12 TWh generated in 2007/08, hydropower is only projected to grow to 13 TWh by 2029/30, an annual growth rate of just 0.2 per cent.[67] All future growth is projected to come from small hydro due to lack of suitable locations for new large hydro construction and competition for scarce water resources.[68]

2.3.8 Geothermal

Australia is considered to have considerable geothermal energy potential. However, the resources are at present uneconomic to develop due to suboptimal heat for power generation at the sites and distance from demand centres. There is major investment in geothermal research and geothermal power generation is projected to increase to 6 TWh by 2029/20, from under 1 TWh in 2007/08.[69]

As of the end 2009, there was one geothermal project in operation in Australia at Birdsville in Queensland, an 80 kW project developed by Ergon Energy in 1992. Interest is growing and in 2010 two companies were developing demonstration projects in South Australia, and other companies were investigating potential in New South Wales, Victoria, South Australia and Western Australia.[70] Major geothermal projects are listed in Table 2.14. In 2008, the government launched the Geothermal Drilling Program, which provides assistance to companies seeking to develop geothermal energy with the proof-of-concept projects. The program has AUD 50 million in available funding. In December 2009, five companies were

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[65] Construction of Whyalla Solar Power Station Begins, Power Technology, July 2009. Available at <www.power-technology.com/news/news58816.html>; Cara Jenkin, Whyalla Solar Power Station Begins, Adelaide Now, 3 July 2009. Available at <www.news.com.au/adelaidenow/story/0,22606,25725160-2682,00.html>.
[66] Ministry of Resources, Clean Energy Initiative. Available at <www.ret.gov.au/Department/Documents/CEI Fact Sheet (13 May 09).pdf>.
[67] ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.
[68] ABARE, Solar Energy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.
[69] ABARE, Australian Energy Projections to 2029-30, 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energy_proj.pdf>.
[70] ABARE, Energy in Australia 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/energyAUS2010.pdf>.

given grants totalling AUD 7 million to conduct test drilling and feasibility studies for geothermal development.[71]

Table 2.14: Major geothermal power projects in Australia as of the end of 2009

Project	Developer	Location	Expected completion completed	MW	Project cost (AUD million)
Geelong Geothermal Power Project	Greenearth Energy	Geelong, Victoria	2015	140	104 (for 12 MW demonstration stage)
Koroit	Hot Rock	Port Fairy, Victoria	2013-14	50	N/A
Moomba stage 2	Geodynamics	Moomba, South Australia	2013	25	N/A
Paralana	Petratherm/Beach Petroleum/TRU energy	Moomba, South Australia	N/A	30	200
Penola	Panax Geothermal	Limeston Cost, South Australia	N/A	59	340

Source: ABARE, Electricity Generation: Major Development Projects April 2010. Available at <www.abareconomics.com>; ABARE, Geothermal Energy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

2.3.9 Marine (Wave/Tidal)

The government is promoting the development of wave and tidal power in Australia. In terms of resources, Western Australia has the best tidal flows, while Victoria and Tasmania are the best for developing wave power. As of the end of 2009, four demonstration projects have been completed (see Table 2.15).

Table 2.15: Marine power demonstration projects in Australia

Project	Developer	State	Date started	Capacity
Portland (wave energy)	Ocean Power Technologies	Victoria	2002	20 kW
Freemantle (wave energy)	Carnegie Wave Power	Western Australia	2005	100 kW
Port Kembia (wave energy)	Oceanlix	New South Wales	2006	450 kW
San Remo (tidal energy)	Atlantis Resource Corporation	Victoria	2005	150 kW

Source: ABARE, Ocean Energy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

Atlantis Resource Corporation plans to increase the size of its San Remo tidal project to 400 kW and install a 1.2-MW tidal plant from Neurus in Western Australia that should be operational later in 2010. BopPower Systems in Tasmania is planning on installing a 250-kW pilot tidal power installation with a bioSTREAM turbine.

Carnegie Wave Power has five project sites around the country where it is investigating potential location for a 5 MW demonstration wave plant using the CETO 3 wave converter. Ocean Power Technologies is planning to increase the Portland wave power project to 19

[71] Department of Resources, Energy and Tourism, Geothermal Drilling Program. Available at <www.ret.gov.au/energy/energy programs/RenewableEnergyFund/Geothermal_drilling_program/Pages/GeothermalDrillingProgram.aspx>.

MW to demonstrate the scalability of its equipment.[72] There are three large commercial projects that are applying for planning permission, all using tidal power (see Table 2.16) and all being developed by Tenax Energy, an Australian developer.

Table 2.16: Commercial marine power projects in Australia as of April 2010

Project	Developer	Location	Capacity (MW)	Expected completion date
Banks Strait Tidal Energy Facility	Tenax Energy Pty Ltd	Banks Strait, Tas	302	2015
Clarence Strait Tidal Energy Project	Tenax Energy Pty Ltd	Clarence Strait, NT	450	2013
Port Phillip Heads Tidal Energy Project	Tenax Energy Pty Ltd	Port Phillip Heads, Vic	34	2014

Source: ABARE, Electricity Generation: Major Development Projects April 2010. Available at <www.abareconomics.com>.

2.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. *A high debt ratio may lead to negative change in the incentive policy for renewable energy.*	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	1	**1/5**
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	0	

2.4.1 Government Structure

Australia operates a federal democratic political system, with a 150-member House of Representatives for which members are elected for three years.[73] The 2007 national election was won by the Labour Party, led by Kevin Rudd, whose first official act as prime minister was to sign the Kyoto Protocol, which was not signed under the previous Conservative government. In 2010, Rudd resigned as prime minister and was replaced by Julia Gillard.

In the latest national elections held on 21 August 2010, the Labour party under Gillard received 72 seats, the same number as the opposition coalition. Gillard was able to form a

[72] ABARE, Ocean Energy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.
[73] The Economist, Country Briefings – Australia. Available at <www.economist.com>.

coalition government with the support of the Green Party and independents. During the election, Gillard has said she would not introduce a carbon tax or cap-and-trade system, but the Green Party member of the coalition continues to push for it.[74] The opposition Conservative Party is against the cap-and-trade system.

2.4.2 Government Debt

The global financial crisis did not affect Australia to the same extent as other countries, as real investment barely contracted in 2009 and the unemployment rate only went up by 2 percentage points. Economic growth up to 2015 is projected to be strong due to the demand for Australia's natural resources from developing Asian countries, China in particular.[75]

Due to economic stimulus programmes, the net debt in Australia is increasing. The government estimated that Australian federal government's net debt in 2010/11 will be AUD 80.6 billion, or 5.7 per cent of GDP, compared to AUD 16.2 billion, or 1.8 per cent of GDP, in 2008/09. Net debt is projected to rise to AUD 89.2 billion, 6.0 per cent of GDP, and then to fall starting in 2012/13 as the government returns to surplus budgets.[76]

The states in Australia carry their own debts in addition to the central federal government. However, the debt levels in the states are not considered risky by investors as it is believed the central government will prevent any problems.[77]

2.4.3 Targets and Commitments

Australia has committed to a Kyoto protocol's target of limiting the increase in GHG emissions to 8 percent between 2008 and 2012 based on a 1990 base-line, and a long-term national target of reducing GHG emissions by 60 per cent from the 2000 base-line level by 2050 (see Table 2.17).[78]

Australia emitted approximately 553 Mt CO_2-e (million tonnes of carbon dioxide equivalent) in 2008, a 1 per cent increase from 2007 and a 7 per cent increase from the 1990 base-line level. In other words, Australia is currently meeting its Kyoto protocol commitment, while only a 1 per cent further increase in emissions is allowed by 2012. In 2007, emissions from power generation accounted for 199.5 Mt, or 36.9 per cent of total emissions. As of May 2009, preliminary reports suggested that emissions from power generation had increased by 0.4 per cent in 2008 relative to 2007 levels.[79] There is a cap-and-trade emissions system in place in New South Wales and the Australia Capital Territory. Industries, including power

[74] Karlis Salna, Carbon tax no certainty: Crean, Sydney Morning Herald, 3 October 2010. Available at <news.smh.com.au/breaking-news-national/carbon-tax-no-certainty-crean-20101003-162dt.html>.
[75] Yan Sun, Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis, IMF Working Paper, May 2010. Available at <www.imf.org/external/pubs/ft/wp/2010/wp10127.pdf>.
[76] Australian Treasury, Pre-Election Economic and Fiscal Outlook, July 2010. Available at <www.treasury.gov.au/documents/1858/PDF/PEFO_2010.pdf>.
[77] Geoffrey Rogow, Queensland Is King In Australia's Debt Market, Wall Street Journal, 21 July 2010. Available at <blogs.wsj.com/marketbeat/2010/07/21/queensland-is-king-in-australias-debt-market/>.
[78] Department of Climate Change, 'Kyoto Protocol'. Available at <www.climatechange.gov.au/international/kyoto/index.html>.
[79] Department of Climate Change, Australia's National Greenhouse Accounts, May 2009. Available at <www.climatechange.gov.au/inventory/2007/pubs/nggi_2007.pdf>.

utilities, must meet government defined standards on emissions. Companies that exceed the standards can sell certificates to companies that do not.[80]

Under the RET system, Australia has set a national target of a 20 per cent share of renewables in its electricity supply by 2020, which represents an additional 45,000 GWh of renewable electricity generation from the 1997 base year. In 2007, renewable electricity generation stood at 6,169 GWh, significantly higher than the target of 5,600 GWh. There is currently no government target for renewable energy consumption. While some individual states and territories have set individual emissions and renewable electricity targets, the expanded RET scheme will integrate all of these targets into a single national goal. However, South Australia has retained its own renewable power targets.

Table 2.17: Australian government commitments

GHG emissions	A Kyoto Protocol target of limiting the increase in GHG between 2008 and 2012 to 8 per cent above the 1990 base-line level. A national target of reducing GHG emissions by 5 to 15 per cent from 2000 levels by 2020 and 60 per cent by 2050.
Renewable energy (RE)	None
Renewable electricity	20 per cent share of renewables in electricity supply under the RET system.

Source: Department of Climate Change, Enhanced Renewable Energy Target Factsheet 2010. Available at <www.climatechange.gov.au/government/initiatives/~/media/publications/renewable-energy/enhanced-ret-fs-pdf.ashx>.

2.4.4 Public Sentiment

In June 2007 the Australia Institute, an independent public policy research centre, commissioned a study to establish which power generating technologies the Australian public would prefer. Slightly less than three-quarters of respondents stated that they would like an energy policy based upon energy efficiency improvements and renewable energy, although it was not asked whether they would be willing to accept higher electricity bill to increase the use of renewable electricity. Less than a fifth of the respondents preferred to have an energy policy based upon nuclear power and clean coal technologies.[81] In a survey conducted by Newspoll in September 2008, 58 per cent of respondents said they would be willing to pay more for their energy sources (petrol, electricity and gas) if it would help slow global warming. Just over a third of respondents would be unwilling to pay more.[82] In an earlier Australia Institute survey, half of the respondents claimed to oppose the construction of nuclear power plants in Australia, and two-thirds would oppose construction in their local area.[83]

[80] Greenhouse Gas Reduction Scheme. Available at <www.greenhousegas.nsw.gov.au>.
[81] The Australia Institute, ‘Greenhouse Strategies – What Do Australians Prefer?’, June 2007. Available at <www.tai.org.au/index.php?q=node%2F19&pageID=2&pubid=470&act=display>.
[82] News poll, Carbon Pollution Reduction Scheme Poll, 28 July 2009. Available at <www.newspoll.com.au/image_uploads/0707 Carbon Pollution Reduction Scheme.pdf>.
[83] The Australia Institute, ‘Who Wants a Nuclear Power Plant? Support for Nuclear Power in Australia’, January 2007. Available at <www.tai.org.au/index.php?q=node%2F19&pageID=2&pubid=443&act=display>.

Green power schemes, where customers are able to purchase renewable power from their utility, are becoming increasing popular. As of 2008, 900,000 customers had signed up for various green power schemes offered.[84]

2.5 Grid Connection Risk Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Non-Discriminatory Access</td><td>One point if the transmission function is not legally separated from generation.
If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid.</td><td>0</td><td rowspan="4">**3/5**</td></tr>
<tr><td>Availability and Clarity</td><td>Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.</td><td>2</td></tr>
<tr><td>Costs</td><td>One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.</td><td>1</td></tr>
<tr><td>Investment</td><td>One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.</td><td>0</td></tr>
</table>

2.5.1 Functional Separation

Prior to 1990, each Australian state and territory[85] had a vertically-integrated state-owned utility that was responsible for much of the generation, transmission, distribution and supply of electricity.[86] In 1990, the liberalisation of the power market and breaking up of the energy authorities owned by states and territories started. Transmission assets in Australia are either still owned and operated by state governments or under private business arrangements (see Table 2.18).

The National Electricity Market (NEM) is a wholesale electricity market linking the six individual state-based networks of the Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria and Tasmania. The individual networks are linked by six major cross-border transmission interconnectors (see Table 2.19) and represent approximately 90 per cent of electricity consumption in the country. Western Australia and Northern Territory are not connected to the NEM due largely to their distance from the other electricity markets in Australia. The NEM operates a wholesale pool system whereby all sales of electricity must go through the Australian Energy Market Operator (AEMO). The Australian Energy Regulator (AER) regulates the transmission business in the NEM under the framework established in the National Electricity Rules.

[84] GWEC, Global Wind Report 2009, 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.
[85] There are six states (Queensland, South Australia, Tasmania, Victoria, Western Australia and New South Wales) and three territories (Australian Capital Territory, Jervis Bay Territory and Northern Territory).
[86] Australian Competition & Consumer Commission, 'Infrastructure Industries – Energy', March 2000. Available at <www.accc.gov.au>.

Table 2.18: Transmission system operators in Australia

National Electricity Market		
Location	**Operator**	**Owner**
New South Wales	TransGrid	New South Wales Government
	Energy Australia	New South Wales Government
Victoria	SP AusNet	Singapore Power International (51%)
Queensland	Powerlink	Queensland Government
South Australia	ElectraNet	Powerlink (Queensland Government),YTL Power Investment, Hastings Utilities Trust
Tasmania	Transend	Tasmanian Government
Non-NEM regions		
Location	**Operator**	**Owner**
Western Australia (SWIS)	Western Power	Western Australian Government
Western Australia (NWIS)	Horizon Power	Western Australian Government
Northern Territory	Power and Water Corp	Northern Territory Government

Source: Australian Energy Regulator, *State of the Energy Market 2008*. Available at <www.accc.gov.au>.

Table 2.19: Major interconnectors linking the NEM transmission networks

From	To	Forward capability (MW)	Reverse capability (MW)
New South Wales	Queensland	486	1,078
New South Wales	Queensland	105	234
Snowy	New South Wales	3,309	1,090
Victoria	Snowy	1,361	1,786
Victoria	South Australia	460	300
Victoria	South Australia	220	220
Tasmania	Victoria	594	469

Source: Department of Resources, Energy and Tourism, *Energy in Australia 2009*. Available at <www.ret.gov.au/energy/Documents/facts statistics publications/energy_in_aus_2009.pdf>.

In Western Australia, the Australian electricity network is divided into several separate systems including the South West Interconnected System (SWIS), the North West Interconnected System (NWIS), and 29 regional non-interconnected power systems. SWIS is the largest system, serving Perth and other urban centres in the south west of Western Australia, and Western Power is the state-owned transmission systems operator (TSO). In the SWIS, bilateral contracts between generators and suppliers account for 95 per cent of all consumption, with spot trading primarily for balancing. Unlike the NEM, there is also a mechanism for capacity payments to generators that are able to guarantee their availability. The Independent Market Authority acts as the system operator for the SWIS. The NWIS largely serves mining industry communities in the Pilbara Region of Western Australia. There are four companies that are involved in the ownership and operation of NWIS: Horizon Power, Pilbara Iron, Alinta and BHP Billiton. The electricity market regulator in Western Australia is the Economic Regulation Authority of Western Australia. In the Northern Territories there are three small regulated power systems with a combined capacity of 444 MW in 2009. The largest system, around the city of Darwin, accounted for the majority of installed capacity in the Northern Territory with 342 MW. The Utilities Commission of the Northern Territory is the electricity market regulator in that state.[87]

Australia has 15 major distribution system operators (DSOs), 13 of which are located within the NEM (see Table 2.20).

[87] Australian Energy Regulator, State of the Energy Market 2009. Available at <www.accc.gov.au>.

Table 2.20: Distribution system operators in Australia

National Electricity Market regions		
Location	**Operator**	**Owner**
New South Wales	Energy Australia	New South Wales government
	Integral Energy	New South Wales government
	Country Energy	New South Wales government
Australian Capital Territory	ActewAGL	ACTEW Corporation (ACT government) 50 per cent; Jemena (Singapore Power International) 50 per cent
Victoria	Solaris	Jemena (Singapore Power International)
	SP AusNet	SP AusNet; Singapore Power International 51 per cent
	United Energy	Jemena (Singapore Power International) 34 per cent; DUET Group 66 per cent
	CitiPower	Cheung Kong Infrastructure/Hong Kong Electric Holdings 51 per cent; Spark Infrastructure 49 per cent
	Powercor	Cheung Kong Infrastructure/Hong Kong Electric Holdings 51 per cent; Spark Infrastructure 49 per cent
South Australia	ETSA Utilities	Cheung Kong Infrastructure/Hong Kong Electric Holdings 51 per cent; Spark Infrastructure 49 per cent
Queensland	Energex	Queensland government
	Ergon Energy	Queensland government
Tasmania	Aurora Energy	Tasmanian government
Non-National Electricity Market regions		
Location	**Operator**	**Owner**
Western Australia	Western Power	Western Australia government
Northern Territory	Power and Water	Northern Territory government

Source: Australian Energy Regulator, *State of the Energy Market 2008*. Available at <www.accc.gov.au>.

2.5.2 Grid Capacity

The vast majority of electricity in Australia is produced at large fossil-fuel power plants located near to coal and gas reserves. Consequently, the transmission networks are designed to transport electricity from these large stations to demand centres.[88] Grid congestion is already a problem in the NEM. The Australian Energy Regulator has reported that the annual cost of transmission congestion to the economy has risen from approximately AUD 36 million in 2003/04 to AUD 83 million in 2009/09. Geographically, congestion has largely impacted the south east of Queensland and at interconnection points between regions upon which the NEM is dependent. The AER has responded by approving significant investment in transmission capacity in Queensland.[89]

In a report commissioned by the Australian Energy Market Commission (AEMC), it is anticipated that renewable power investment is likely to 'cluster' in the remote regions of northwest Tasmania and South Australia. This will increase the amount of grid congestion in these areas. The AEMC recommends increasing grid capacity as well as improving the congestion management system. A final report on grid congestion in Australia is expected at the end of 2010.[90] Approximately AUD 4 billion of additional investment for the grid is required to meet the 2020 RET target of an additional 45,000 GWh of renewable electricity generation.[91]

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[88] Clean Energy Council, All about Systematic Barriers. Available at < cleanenergycouncil.org.au>.
[89] Australian Energy Regulator, State of the Energy Market 2009. Available at <www.accc.gov.au>.
[90] AEMC, Review of Energy Market Frameworks in light of Climate Change Policies, 8 October 2009. Available at <www.aemc.gov.au>.
[91] Bruce Hextall and David Fogarty, Reuters, 'ANALYSIS – Australia set for renewable energy boom', 04 February 2009. Available at <communities.thomsonreuters.com/Carbon/208189>.

2.5.3 Access and Connection Cost

The Australian National Electricity Rules state that all developers should have the opportunity to connect to the network. The terms and conditions of connection are set out in commercial agreements on 'reasonable terms' between the developers and network service providers (NSP).[92] The National Electricity Rules do not entitle renewable power generators to preferential grid access.[93] Additionally, under the current open access structure for generator connections, network service providers are required to make an offer for connection, yet there is no obligation to extend the network to a generator's power plant in order to enable that connection.[94] Developers have reported that the existing connection procedure, based upon bilateral discussion between the developer and the NSP, prevents savings that may be made through co-ordinated discussions between multiple developers and the NSP. Consequently, there is often a duplication of network assets and a delay in connection.[95]

Developers must pay a deep connection charge that includes the cost of any grid enhancements required for connection. The National Electricity Rules require a connection agreement, which is both fair and reasonable between developers and network service providers.[96] Grid connection charges form a significant barrier for renewable power development as those plants are often located remotely from the grid. In 2006, the Australian Government's Ministerial Council of Energy launched a public consultation in relation to a discussion paper on the impediments to the uptake of renewable and distributed generation. The National Electricity Market Management Company (NEMMCO) has noted that incremental network planning makes long-term network connection costs higher for wind power and other renewable technologies. Renewable Energy Generators Australia (REGA), a national body representing leading generators, has stated that it is difficult for small generators to negotiate fair connection costs with a monopoly network supplier. Victoria has implemented an Act allowing the least-cost option for network upgrades for the connection of multiple wind sites. The Act also allows project developers to negotiate their fair share of the connection and upgrade costs.[97]

Long lead times to obtain connection to the grid are an issue that has been identified as a barrier to the development of renewable power, particularly for wind power as the projects tend to be larger.[98] It is estimated that 8,000 MW of renewable power capacity will have to be added to the system between 2009 and 2020 in order to meet the government's 2020 targets. According to the AEMC, the network connection procedures will hamper development,

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[92] Hon. Patrick Conlon MP, National Electricity Rules, July 2005. Available at <www.ret.gov.au>.
[93] Clean energy Council, Clean Energy Fact Sheets – All about Systematic Barriers. Available at <cleanenergycouncil.org.au>.
[94] GridAustralia, 'Review of the Energy Market Frameworks in Light of Climate Change Policies', 14 May 2009. Available at <www.aemc.gov.au/Media/docs/Public Forum - Melbourne - Grid Australia-ef723833-f43d-43c6-90e4-11ae0bb5d87d-0.pdf>.
[95] The Australian Energy Market Commission, Review of Energy Market Frameworks in Light of Climate Change Policies – Second Interim Report, June 2009. Available at < www.aemc.gov.au/Media/docs/Second Interim Report-5b4f2d74-8c01-4546-8805-c992d196e35f-0.PDF>.
[96] National Electricity Rules, July 2005. Available at <www.ret.gov.au>.
[97] Renewable Energy Generators Australia, Discussion Paper: Impediments to the Uptake of Renewable and Distributed Energy, March 2006. Available at <www.ret.gov.au/Documents/mce/_documents/REGA20060405132736.pdf>.
[98] ABARE, Wind Energy, Australian Energy Resource Assessment 2010. Available at <www.abareconomics.com/publications_html/energy/energy_10/ga_aera.html>.

primarily due to the long lead times required for generators to obtain connection in some areas, especially more remote areas where renewable power tends to be developed due to resource availability. The AEMC has recommended that transmission charging should be modified to promote the development of clusters where renewable power could be developed (for example, sites with good wind resources). Also, as the first developer has to pay for the costs of grid enhancement, there are complaints that later developers are benefiting from the grid enhancement that were paid for by previous developers, and they are not obliged to contribute towards the costs.[99]

2.6 Planning Permission Risk Index

Measure		**Value**	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	0	**0/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

2.6.1 Complexity and Expected Timescales

For offshore wind and tidal projects, state law applies up to three nautical miles (5.6 km) from shore. The federal government is responsible for projects that are beyond that distance in the Exclusive Economic Zone.[100] However, even if the project is based in federal waters, the federal government is legally obliged to consult with the adjacent state with respect to the project. Furthermore, all installations that interfere with navigation or fishing or that affect a protected species or habitat are prohibited.[101]

There are no specific federal laws that dictate how energy projects are to be developed. However, all projects that could affect the environment require an environmental assessment under the federal Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act).

As state law also requires environmental assessments for projects, there are many cases where jurisdiction overlaps and could potentially lead to the need for two different environmental impact statements to be prepared; one for the federal government and one for

[99] AEMC, Review of Energy Market Frameworks in light of Climate Change Policies, 8 October 2009. Available at <www.aemc.gov.au/Market-Reviews/Completed/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html>.
[100] See Offshore Petroleum Act 2006, Act no, 88 of 2008.
[101] Commonwealth of Australia, Sea Installations Act 1987, as amended 2005.

the state government. This situation would most frequently occur when the project is large as it would impact both jurisdictions. In order to facilitate development and to reduce delays, bilateral agreements between states and the federal government allow the states to undertake the environmental assessment, eliminating the duplication between the two levels of government.[102] Some states are working with the industry to develop Renewable Energy Zones (REZ), which are areas that have good resources and would be suitable for development, to reduce the planning burden.

In Queensland, renewable energy developers have complained about a lack of clarity with issues related to land planning, land access, native title, royalty and fee regimes. Under existing rules, a renewable energy development in Queensland may be subject to a substantial range of regulatory requirements, instruments and plans before planning permission may be granted.[103] The Victorian Sustainable Energy Authority released guidelines for the development of wind power installations in 2003. These guidelines established a framework in which the State Minister for Planning is responsible for assessing all renewable projects that are 30 MW or above. Under the guidelines, wind power installations will only be excluded from land reserved under the National Parks Act, 1975.[104]

2.6.2 Local Opposition and Procedural Improvements

Because of the remote location of many wind farms in Australia, they are rarely subject to the same level of local opposition to wind farms as seen in other countries. However, there are examples of localised opposition to individual projects such as the Capital Wind Farm located on the shores of Lake George, near Bungendore in New South Wales.[105]

In July 2009, the federal government released the first of two policy statements detailing how the Environmental Protection and Biodiversity Conservation Act 1999 will impact on the planning process of potential wind farm projects.[106] In October 2009, the Environment Protection and Heritage Council released a draft of the National Wind Farm Development Guidelines for public consultation. The guidelines will set national standards for wind farm planning to ease planning problems. Final guidelines are expected to be completed by the end of 2010 or early 2011.[107]

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[102] For information, see Best Practice Guidelines, 2007. Available at <www.cleanenergycouncil.org.au/cec/accreditation/certified-wind-farms-australia/Best-Practice.html>. For information on the EPCB can be found at the Department of Environment's website at <www.environment.gov.au/epbc>.
[103] Queensland Government, The Queensland Renewable Energy Plan – A Clean energy Future for Queensland, June 2009. Available at <www.qld.gov.au>.
[104] Sustainable Energy Authority Victoria, Policy and Planning Guidelines for Development of Wind Energy Facilities in Victoria, May 2003. Available at <www.sustainability.vic.gov.au/resources/documents/WindEnergyGuidelines.pdf>.
[105] Rosslyn Beeby, 'Fierce opposition to huge wind turbines 'scarring' Bungendore landscape', Canberra Times, March 2006. Available at <www.canberratimes.com.au>.
[106] Department of the Environment, Water, Heritage and the Arts. EPBC Act Policy Statement 2.3 – Wind Farm Industry, July 2009. Available at <www.environment.gov.au/epbc/publications/pubs/wind-farm-industry.pdf>.
[107] Environment Protection and Heritage Council, Climate Chante. Available at <www.ephc.gov.au>.

2.7 Conclusion

Australia has excellent resources for renewable power development, particularly for onshore and offshore wind, solar PV and biomass. There is also a strong need for increased renewable electricity generation if the RET targets are to be met. Although the RET legislation suffered from setbacks in parliament, it was finally passed in August 2009, and the TGC system and quota came into force on 1 January 2010. The RET has established an ambitious target for renewable electricity generation, and by extending the TGC by 10 years until 2020, there is now more certainty provided to potential investors. The support offered by the RET may not be sufficient for many renewable power generating technologies, therefore, additional support is essential.

There is strong public support in Australia for renewable electricity generation, and it appears unlikely that there will be nuclear power development under the existing Labour government. Given Australia's reliance on coal-fired generation and its lack of other significant fossil-fuel resources, renewable power will be necessary if Australia is to meet greenhouse gas emissions targets. However, opposition parties in the Senate have managed to block the cap-and-trade legislation which would have increased the cost of generating electricity from coal, and the Labour coalition government may find it difficult to push through renewable-energy friendly policies.

In addition to the federal renewable power generation incentives, most state governments have introduced a series of FIT systems to promote micro-generation from households and businesses.

Chapter 3: China

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
For wind power, a feed-in tariff (FIT) system is available, while network operators are obliged to take other renewable power at a negotiated fair price. A capacity-based renewable portfolio standard has been introduced.	**5/5**

2. Power Market Opportunities Index	Value
A significant demand exists for additional generating capacity by 2020. Nuclear power is expected to increase.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Onshore wind
Emerging Technologies Technologies that have growth potential in the country.	Offshore wind, Solar power, Marine energy

Risk Indices

4. Political Will Risk Index	Value
Deployment of renewable energy (RE) is strongly supported by both the government and the public. Nuclear power is also supported.	**1/5**

5. Grid Connection Risk Index	Value
Transmission capacity constraints are leading to substantial delays — particularly for wind power projects. Grid operators are investing in upgrading and reinforcing the grid, but it may take a number of years for the work to be completed.	**2/5**

6. Planning Permission Risk Index	Value
The planning process has led to delays to some projects, mostly affecting those in urban areas.	**1/5**

3.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.*	3	**5/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	1	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.*	1	

3.1.1 Operating Incentives

The basis of the Chinese government's support for renewable power development is the 2006 Renewable Energy Law, which was revised in 2009. Under the 2006 law, all renewable power output must be purchased by the local grid operators at a fair price; however, unlike a typical feed-in tariff (FIT) system, there was no set tariff rate set in the 2006 law at which renewable electricity produced is purchased. Instead, once a developer was awarded the rights to a project, the developer and the National Development and Reform Commission (NDRC) negotiated the purchase price on a case-by-case basis, similar to a tender system, where developers propose prices in competition with each other. The rates agreed were guaranteed, usually for 20 years.

In amendments to the law passed in December 2009, the government was given the power to introduce fixed FIT rates for renewable electricity and it subsequently introduced fixed FIT rates for wind power, differentiated by region, and guaranteed for 20 years.[1] The purchase price for projects other than wind power are determined on a case-by-case basis. The government had previously indicated that it would introduce fixed FIT rates for solar power. However, the plan has been delayed and it is not known when or if it will be realised.

The government agreed that solid biomass- and biogas-based power plants commissioned in 2010 will receive a fixed premium of 350 CNY/MWh (38.49 EUR/MWh[2]) for 15 years, in addition to the local wholesale purchase price of sulphur-removed coal-fired generation (the premium for 2009 was 250 CNY/MWh).[3] While the purchase price of coal-fired power varies depending on the province, the average wholesale market price in 2009 was between 300 and

[1] National Development and Reform Commission, 全国风力发电标杆上网电价表 (Benchmarks for National Wind Power Rates), 2009. Available at <www.sdpc.gov.cn/zfdj/jggg/dian/W020090727546284276176.pdf>.
[2] The CNY-EUR conversion rate used is EUR 1 = CNY 9.09399 (the average over the first six months of 2010).
[3] 尹成杰委员：尽快实行全国统一的生物质发电上网电价 (Biomass Price Required), August 2009. Available at <npc.people.com.cn/GB/9933131.html>.

400 CNY/MWh (32.99-43.99 EUR/MWh),[4] which would give biomass-based generators an average income of 650-750 CNY/MWh (71.48-82.47 EUR/MWh). In many cases the provincial price authority will set a specific amount for biomass and biogas generation (in 2010, the average amount set by the provinces was 750 CNY/MWh for all biomass and biogas generation).

Table 3.1 compares the FIT rates for wind power, differentiated by region; the rate agreed for five solar PV plants licensed in 2010;[5] and the aforementioned biomass-based income.

Table 3.1: Comparison of tariff rates/income for renewable electricity by technology

Description		CNY/MWH	EUR/MWh
FIT rates for wind power (2009)[a]	Inner Mongolia, some cities in Xinjiang Uighur Autonomous Region	510	56.08
	Some parts of Hebei province, four cities in Inner Mongolia, and three cities in Gansu Province	540	59.38
	Two cities in Jilin Province, five cities in Heilongjiang Province, Ningxia Hui-Muslim Autonomous Region, and most parts of Gansu Province and Xinjiang Uighur Autonomous Region	580	63.78
	Other and offshore	610	67.08
Price given to four solar PV plants licensed in April 2010 (>50 kW)[b]		1,150	126.46
Price proposed for a 20 MW solar PV plants licensed in August 2010[c]		730	85.47
Indicative income for biomass-based generators[d]		650-750	71.48-82.47

Note:[d]See discussion above.
Source: [a]National Development and Reform Commission, 全国风力发电标杆上网电价表 (Benchmarks for National Wind Power Rates), 2009. Available at <www.sdpc.gov.cn/zfdj/jggg/dian/W020090727546284276176.pdf>; [b]National Development Reform Commission, 国家发展改革委关于宁夏太阳山等: 四 个太阳能光伏电站临时上网电价的批复(Four Solar PV Installations Approved), 2010. Available at <www.ndrc.gov.cn/zcfb/zcfbtz/2010tz/t20100409_339707.htm>; [c]Reuters, China firms offer $0.108/kWh feed-in rate in solar tender, 16 August 2010. Available at <www.reuters.com/article/idUSTRE67F2BJ20100816>.

In the 2006 Renewable Energy Act, the government introduced a capacity-based renewable portfolio standard (RPS), which states that all power generators with more than 5 GW of installed capacity need to meet a requirement that at least 3 per cent of their installed capacity should be non-hydro renewable power capacity by 2010, and this requirement will be raised to 8 per cent in 2020. In addition, all grid operators must ensure that 1 per cent of the electricity carried on their networks is non-hydro renewable electricity in 2010, and this requirement will be raised to 3 per cent in 2020.[6]

[4] Numbers from China Electric Power Network. Available at <www.power.net.cn>.
[5] Coco Liu, Is China Putting the Brakes on its Solar Programme?, GreentechSolar, 22 April 2010. Available at <www.greentechmedia.com/articles/read/is-china-putting-the-brakes-on-its-solar-program/>.
[6] Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf>; NRDC, 刘琦副局长在《可再生能源法》（修订）实施座 谈会上的讲话 (Liu Qi, deputy director on the “Renewable Energy Law” (revised): Speech at the Forum on the Implementation, 16 March 2010. Available at <nyj.ndrc.gov.cn/nygz/t20100427_343167.htm>.

3.1.2 Investment Support

3.1.2.1 Solar Power Incentives

The government provides investment subsidies for the development of solar PV power. Under the 2009 Solar Roofs Programme, the government offers up to 20 CNY/W (2.92 USD/W) for roof-top installations of 50 kW or more. The grant is available for both on-grid and off-grid applications. The total yearly amount of the grant is decided by the Ministry of Finance.[7] In August 2009, the government announced that 111 projects totalling 91 MW were approved for the grant in the first phase.[8] The government updated its incentives for the Solar Roofs Programme for new projects in 2010, and is now offering 17 CNY/W (2.49 USD/W) for building-integrated PV systems, and 13 CNY/W (1.90 USD/W) for building-attached PV systems. The minimum required capacity of 50 kW still remains.[9]

For large ground-based solar power installations, the government has introduced the Golden Sun Programme. Under this programme, the government offers subsidies that cover up to 50 per cent of the investment costs for solar PV installations of 300 kW or larger for a maximum total of 20 MW in each province (for off-grid applications, the subsidy is increased to 70 per cent). In November 2009, the government announced that 294 projects, totalling 642 MW, had been approved. Of the total, 232 projects (290 MW) were at industrial and commercial locations and the output was intended for their own consumption, 27 projects (46 MW) were designed to supply power to off-grid areas, and the remaining 35 projects (360 MW) for supply to the main power grid.[10]

3.1.2.2 Tax Incentives

The VAT charged on the purchase of electricity generated from wind power is 50 per cent lower than that from other sources.[11] In addition, enterprises engaged in projects involving renewable power can claim a three-year exemption from corporate tax, plus another three years of tax reduction at 50 per cent.[12] Customs duties on imported renewable energy technology are reduced to between 1 and 5 per cent and can be waived entirely if it can be demonstrated that the technology is essential to the project concerned.[13] Most local governments can and do exempt wind power plants from paying land-use tax.

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[7] Ministry of Finance, 财政部关于印发《太阳能光电建筑应用财政补助资金管理暂行办法》的通知 (Ministry of Finance on the issuance of "solar financial assistance fund construction applications Interim Measures)," March 2009. Available at <www.cin.gov.cn/zcfg/xgbwgz/200903/t20090326_187941.htm>.

[8] Ministry of Finance, The Government 1.27 billion for Solar Roofs Programme, August 2009. Available at <jjs.mof.gov.cn/zhengwuxinxi/gongzuodongtai/200909/t20090914_207328.html>.

[9] Ministry of Finance, 关于组织申报2010年太阳能光电建筑应用示范项目的通知(Declaration of 2010 of Solar Roofs), March 2010. Available at <jjs.mof.gov.cn/zhengwuxinxi/tongzhigonggao/201004/t20100415_287576.html>.

[10] Ministry of Finance, 加快实施"金太阳"示范工程 促进光伏发电产业发展 (Accelerating the Implementation of the Golden Sun Programme), 13 November 2010. Available at <www.mof.gov.cn/pub/mof/zhengwuxinxi/caizhengxinwen/200911/t20091113_232469.html>.

[11] 尽快出台可再生能源税收优惠细则, New Policies on Renewable Energy Incentives, August 2009. Available at <www.nengyuan.net/200908/26-202290.html>.

[12] Renewable Energy World, A New Revolution, October 2009. Available at <www.renewableenergyworld.com/rea/news/article/2009/10/a-new-revolution-china-hikes-wind-and-solar-power-targets>.

[13] 财政部关于"我国风电事业亟待发展"提案的答复（摘要） Ministry of Finance on Renewable Energy, December 2007. Available at <unn.people.com.cn/GB/134673/141758/141760/8567045.html>.

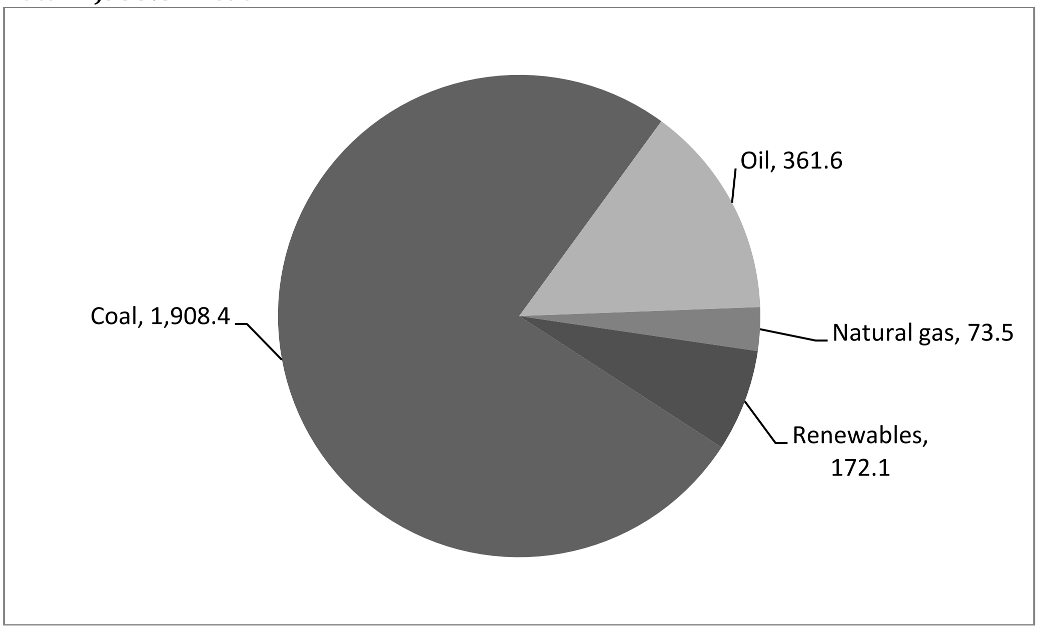
3.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**4/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	2	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants*.	0	

3.2.1 Energy Consumption

Primary energy consumption totalled 1,933.5 millions of tonnes of oil equivalent (Mtoe) in 2008, with coal accounting for nearly 70 per cent (see Figure 3.1). During the intervening 10 years between 1998 and 2008, primary energy consumption increased at a compound annual growth rate of 7.9 per cent. In 2008, 9 per cent of energy consumption came from imported energy sources, primarily gas and oil. The share of imports in energy consumption has been slowly increasing driven by sharp increases in energy demand.[14]

Figure 3.1: Primary energy consumption by source in China in 2008 (Mtoe): Total 1,933.5 Mtoe



Source: National Bureau of Statics of China, China Statistical Yearbook 2009. Available at <www.stats.gov.cn/tjsj/ndsj/2009/indexee.htm>.

[14] National Bureau of Statics of China, China Statistical Yearbook 2009. Available at <www.stats.gov.cn/tjsj/ndsj/2009/indexee.htm>.

3.2.2 Electricity Sector

The total installed generating capacity in China was 860 GW at the end of 2009, up by 67 GW from 793 GW a year earlier. Over three-quarters of total capacity was conventional thermal generating capacity.

At the end of 2009, 178.98 GW of new capacity was under construction, and it is projected that 85 GW of that will be completed in 2010, including 15 GW of hydropower, 55 GW of thermal power, 1.08 GW of nuclear power, 13 GW of wind power, and 200 MW of solar power.[15] Approximately 10 GW of inefficient small-thermal generation is expected to be retired, bringing the total installed capacity at the end of 2010 to 950 GW, nearly three-quarters of which will be conventional thermal capacity (see Figure 3.2).

One half of the power generated in 2008 came from five central-government owned generating companies, Huaneng Group, Datang Group, Huadian Group, Guodian Group and the China power Investment Corporation. Another 40 per cent came from generating companies owned by local governments, and the remaining 10 per cent from private and foreign independent power producers (IPPs).[16]

Electricity consumption totalled 3,658.7 TWh in 2009,[17] a 6.44 per cent increase from 2008 (see Table 3.2). In line with the projected annual GDP growth rate of 10 per cent for 2010, electricity consumption is projected to rise to around 4,000 TWh in 2010, driven mostly by increased demand in the residential and industrial sectors,[18] and to 7,700 TWh by 2020. Installed generating capacity will need to double from 2010 levels to meet consumption by 2020.[19]

Table 3.2: Growth in electricity consumption from 2001 to 2009 in China

Year	Consumption (TWh)	Growth rate (%)
2001	1,463.35	9.3
2002	1,633.15	11.8
2003	1,903.16	15.6
2004	2,197.14	15.4
2005	2,494	13.5
2006	2,858.8	14.6
2007	3,271.18	14.4
2008	3,426.8	5.23
2009	3,658.7	6.44

Source: National Bureau of Statics of China, China Statistical Yearbook 2008. Available at <www.stats.gov.cn/tjsj/ndsj/2008/indexee.htm>; State Electricity Regulatory Commission, 电力与经济形势分析小组 (Power and Economic Analysis), March 2010. Available at <www.serc.gov.cn/jgyj/ztbg/201004/t20100419_12935.htm>.

15 State Electricity Regulatory Commission, 电力消费同比增长９％，全社会用电量呈“前高后低”趋势 (End of This Year Capacity will be 960 GW), March 2010. Available at <www.serc.gov.cn/xyxx/dljs/201004/t20100406_12865.htm>.

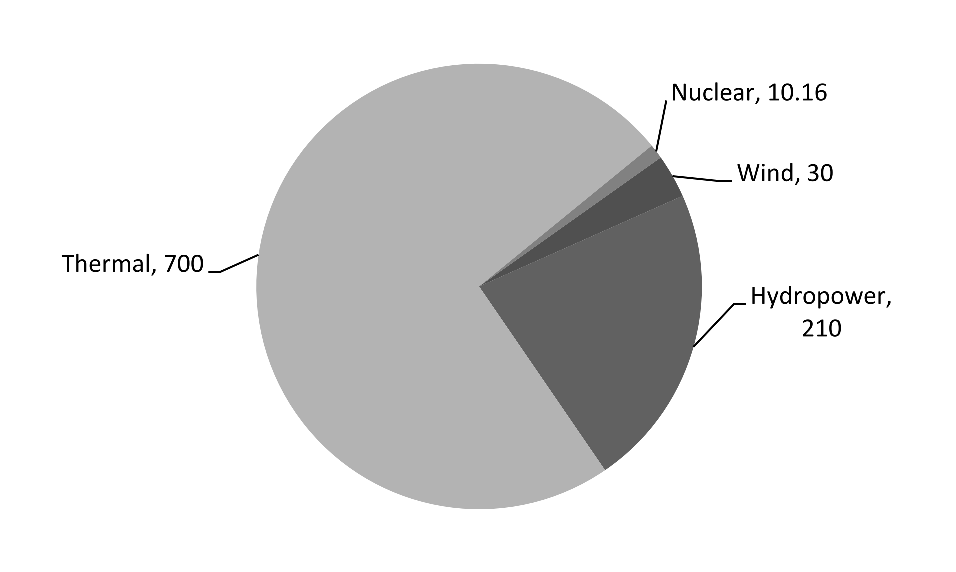
16 Asia Pacific Energy Research Centre, Understanding Energy in China: -Geographies of Energy Efficiency, September 2009. Available at <www.ieej.or.jp/aperc/2009pdf/APERC_China_2009_rev.pdf>.

17 State Electricity Regulatory Commission, 电力与经济形势分析小组 (Power and Economic Analysis), March 2010. Available at <www.serc.gov.cn/jgyj/ztbg/201004/t20100419_12935.htm>.

18 State Electricity Regulatory Commission, Economic Situation and Prospects of Power Review (2009-2010), March 2010. Available at <www.serc.gov.cn/jgyj/ztbg/201004/W020100419358783174325.pdf>.

19 China Knowledge, China Electricity Demand to Double by 2020, May 2009. Available at <www.chinaknowledge.com/Newswires/News_Detail.aspx?type=1&NewsID=23820>.

Figure 3.2: Projected generating capacity mix in China at the end of 2010 (GW)



Source: State Electricity Regulatory Commission, 电力消费同比增长 9 %，全社会用电量呈"前高后低"趋势 (End of This Year Capacity will be 960 GW), March 2010. Available at <www.serc.gov.cn/xyxx/dljs/201004/t20100406_12865.htm>.

3.2.3 Nuclear Power

There were 11 nuclear reactors in operation in China, with a total generating capacity of 8,587 MW, at the end of 2008. In addition, 24 reactors were under construction and another 14 had received government approval. If all of these are completed, they will add a total capacity of 25.5 GW.[20]

3.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Onshore wind
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Offshore wind, Solar power, Marine energy

3.3.1 Renewable Electricity Generation

Renewable power developed rapidly in China in recent years, with wind power alone more than doubling in installed capacity every year between 2000 and 2009. Solar power has also increased, but not as rapidly as wind power (see Table 3.3).

[20] Asia Pacific Energy Research Council, APEC Energy Review 2009, March 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

Table 3.3: Changes in total installed capacity of renewable power in China from 2000 to 2009 (MW)

Technology	2000	2005	2006	2007	2008	2009	CAGR 2000-2008 (%)
Wind power[a]	346	1,260	2,599	5,910	12,020	25,805	61.5[b]
Solar power	19	65	80	100	150	N/A	29.5
Biomass	1,100	2,036	2,120	2,552	2,918	N/A	13
Biogas	0	35	99	157	218	N/A	N/A
Small hydro	24,851	38,534	43,183	47,389	51,300	N/A	9.5

Notes:[b]CAGR is for 2000 to 2009; N/A: Not available.
Source: Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>; bGlobal Wind Energy Council, Global Wind 2009 Report, March 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.

In 2007, the government introduced a *Medium- and Long-Term Development Plan for Renewable Energy in China*, which set targets for renewable power capacity for 2010 and 2020. Those targets needed to be revised upward in late 2009 because of faster-than-expected growth of wind and solar power (see Table 3.4). The government is expected to release a new renewable energy plan in late 2010, which is expected to raise targets further to 300 GW for wind power and 30 GW for solar power by 2020.[21]

Table 3.4: Chinese government targets for renewable power for 2010 and 2020 (GW)

Technology	Status in 2008[b]	2010 target[c]	2020 target		CAGR required to meet 2020 target (%)
			Initial target	Revised target	
Wind power	25.8[a]	10	30	150[d]	17.4
Solar power	0.15	0.3	1.8	20[d]	50.3
Biomass	3.1	5.5	30		20.8
Hydropower	210	190	300		3.0

Notes: [a]Wind power installed capacity is for 2009.
Source: [b]See Table 3 above; [c]Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf>; [d]SEI, 2020年 中国光伏发电剑指2000万千瓦2020 To Proved 20 GW, 7 December 2009. Available at <www.sei.gov.cn/ShowArticle.asp?ArticleID=190093>; NPRC, 国家能源局统一组织开展风电接入和消纳研究工 作(National Energy Board Launches Unified Access), 27 March 2010. Available at <www.ndrc.gov.cn/gzdt/t20100427_343202.htm>.

3.3.2 Resource Potential

The China Meteorological Administration published a wind assessment based on measurements at 50 metres above ground level in 2009, which estimates the total wind power potential of 2,380 GW at sites with a wind power density of over 300 W/m^2. The offshore wind power potential for water depths of up to 25 metres is 300 GW.[22]

The western provinces of China have the best solar resources, with annual solar irradiation levels of about 1,750 kWh/m^2. Table 3.5 shows the distribution of solar resources by region.

[21] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at <www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[22] Global Wind Energy Council, Global Wind 2009 Report, March 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.

Table 3.5: Distribution of solar resources in China

Regions	Yearly average solar irradiation (kWh/m^2)	Per cent of total land area of China
Most parts of Tibet, South Xinjiang, Qinghai, Gansu and West Inner Mongolia	>1,750	17.4
Most parts of Xinjiang, the east of Qinghai and Gansu, Ningxia, Shaanxi, Shanxi, Hebei, the northeast of Shandong, the north of Inner Mongolia, the southwest of Northeast China, Yunnan, the west of Sichuan	1,400-1,750	42.7
Heilongjiang, Jilin, Liaoning, Anhui, Jiangxi, the south of Shanxi, the northeast of Inner Mongolia, Henan, Shandong, Jiangsu, Zhejiang, Hubei, Hunan, Fujian, Guangdong, Guangxi, the east of Hainan, Sichuan, Guizhou, the southeast of Tibet	1,050-1,399	36.3
The midland of Sichuan, the north of Guizhou, the northwest of Hunan	<1,050	3.6

Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

There is an estimated 560 Mtoe of available biomass energy resources in China. Table 3.6 lists the resource availability.

Table 3.6: Potential available biomass resources in China (Mtoe)

Type	2006	2010	2020	2030
Agricultural residues	48.3	61.6	100.1	163.8
Forestry residues	44.1	49.7	63.7	81.2
Animal dung	74.9	84.7	108.5	138.6
Industrial organic wastes	27.3	30.8	39.7	51.1
MSW	0	2.1	4.9	10.5
Energy crops	0	6.3	74.9	116.2
Total	194.6	235.2	391.8	561.4

Source: Derived from NRDC, China Renewable Energy Development Overview, 2008. Available at <www.cresp.org.cn/uploadfiles/7/977/2008en.pdf>.

The country has a large hydropower potential, with an estimated capacity of 540 GW technically feasible and 400 GW economically feasible. The geothermal potential is 6 GW, mostly located in the Tibet, Sichuan and Yunnan provinces.[23] The marine energy potential is totalled at 400 to 500 GW.[24]

3.3.3 Levelised Generation Costs

Table 3.7 compares the operating incentives offered for wind, solar PV and biomass power and the levelised generation costs. For the latter, IEA figures for China in 2008 are used. In general, the operating incentives in China fall within the range of levelised generation costs.

[23] Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf>.

[24] CRESP, China Renewable Energy Development Overview, 2008. Available at <www.cresp.org.cn/uploadfiles/7/977/2008en.pdf>.

Table 3.7: Comparison of the operating incentives for renewable power in China in 2010 and levelised generation costs

Technology	Incentives[a]		Levelised generation costs (EUR/MWh)[c,d]
	CNY/MWh	EUR/MWh	
Wind power (>30 MW)	510-610	56.08-67.08	37.56-66.88
Solar PV >50 kW	1,150	126.46	92.30- 134.59
Biomass	700[b]	76.97	60[e]

Notes: [b]Including the premium of 350 CNY/MWh offered for biomass plus 350 CNY/MWh for the average price of coal fired power in 2009.
[d]Figures for China for wind and solar power with a 5 per cent discount rate are given.
[e]Figures for all the countries .
Sources: [a]See Table 1 above; [c]IEA and NEA, Projected Costs of Generating Electricity: 2010 Edition, Paris: OECD, 2010.

3.3.4 Wind Power

3.3.4.1 Onshore Wind Power

China became the world's largest market for new wind power construction in 2009, expanding its installed capacity from 12.2 GW in 2008 to 25.8 GW at the end of 2009. China now has the world's second largest installed wind power capacity after the USA.[25]

Onshore wind power has been the primary beneficiary of the government's RPS requirement for power generators with more than 5 GW of installed capacity to have a minimum of 3 per cent of generating capacity from non-hydro renewable power sources. This is because wind power, as an established technology, requires the lowest investment cost per kW of all the renewable power technologies, and because biomass projects, which are also cost efficient, tend to be small.[26] About 50 per cent of wind power plants under construction are based on the Clean Development Mechanism (CDM) under the Kyoto Protocol.

The province of Inner Mongolia, which has the best wind resources due to flat terrain and constant wind, has the largest capacity, followed by the Liaoning, Hebei and Jilin provinces.[27] In August 2009, the NDRC and the National Energy Administration started construction in Gansu Province of the first series of six 10-GW 'Three Gorges in the Air' wind farms. The total cost for the six units is estimated at CNY 120 billion (USD 17.6 billion).[28] Table 3.8 shows the government plans for the 'Three Gorges in the Air' project by 2020.

In 2008, the average investment costs for onshore wind power development was 10,277 CNY/kW (1,130 EUR/kW).[29]

[25] Global Wind Energy Council, Global Wind 2009 Report, March 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.
[26] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[27] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[28] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[29] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

Table 3.8: The Chinese government's 'Three Gorges in the Air' wind power project by province

Province	Capacity (by 2020) in GW
Gansu	12.7
Xinjian	10.8
Inner Mongolia (2 projects)	57.8
Jiansu	10.0
Heibei	10.8
Jilin	23.0
Total	125.1

Source: National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at <www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.

In 2007, the government introduced a 10 GW target for onshore wind power development by 2010, and a 30 GW target by 2020. Because the actual progress was much faster, the target of 10 GW was met in 2007. The government now expects that the total capacity of onshore wind power will reach 100 GW by 2020.[30]

The onshore wind power manufacturing sector in China has expanded rapidly. From 2005 until January 2010, projects had to demonstrate that the equipment used was at least 70 per cent sourced locally in order to receive central government's funding. This requirement discouraged multinational wind turbine manufacturers from working with projects sponsored by the central authorities. This did not affect projects under 50 MW, for which no proof of local content was required from the central government as they are licensed by regional authorities. The requirement was dropped in January 2010. However, a common complaint from multinational manufacturers is that they are discriminated against in comparison with their Chinese counterparts. The CEO of Suzlon's Chinese subsidiary has expressed agreement with this complaint noting as well that many multinational manufacturers have stopped bidding for contracts. The three largest Chinese wind turbine manufacturers, Goldwind, Sinovel and Dongfang Electric, accounted for 58 per cent of all new capacity in 2008, and foreign firms accounted for 24 per cent. Smaller Chinese manufacturers provided the remainder.[31]

The Chinese Wind Energy Association is concerned that most of the recent wind power developments have been politically rather than economically motivated. As a result, some projects may prove to be not financially feasible in the long term and public support for further development may be jeopardised. Also, there are reports suggesting that some of the Chinese-made equipment is not up to standard and that the overall quality is falling. Increased maintenance costs in the future represent an unquantified threat to the profitability of existing projects.[32]

[30] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[31] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[32] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.

3.3.4.2 Offshore Wind Power

It is estimated that the total potential for offshore wind power in China is 750 GW, with an achievable target of approximately 100 to 200 GW.[33] Offshore wind power development is just starting in China. In April 2009, the National Energy Agency compiled a list of suitable sites and asked the provincial governments to draft development plans for offshore wind and marine energy projects up to 2020. The first commercial offshore wind farm, the Donghai Daqiao project near Shanghai, a 102-MW wind farm consisting of 34 3-MW Sinovel turbines, started supplying power to the grid in July 2010. Costing CNY 2.3 billion (EUR 253 million), this is the first offshore wind farm completed outside of Europe.[34]

3.3.5 Biomass

3.3.5.1 Solid Biomass

Table 3.9 details the solid biomass power development in China from 2000 to 2008. At the end of 2008, there was just over 4 GW of solid biomass power capacity installed in the country, much of which was not connected to the power grid. The government's targets for biomass power development are 5.5 GW by 2010 and 30 GW by 2020.[35] However, some people in the industry have questioned the feasibility of the latter target on the basis of a lack of available feedstocks.[36]

Table 3.9: Accumulated installed generating capacity of biomass power (MW)

Technology	2000	2001	2002	2003	2004	2005	2006	2007	2008
Direct combustion	0	0	0	0	0	0	25	367	1,700
Bagasse	1,000	1,000	1,500	1,700	1,700	1,700	1,700	1,700	1,700
Gasification	0	0	0	0	1	1	6	10	18
Rice husks	0	0	2	15	25	40	42	45	50
MSW[a]	100	120	150	180	210	300	360	462	603
Total	1,100	1,120	1,652	1,895	1,936	2,041	2,133	2,584	4,071

Note: [a]MSW is municipal solid waste
Source: Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

In 2008, the average investment cost for a solid biomass combustion project was 10,000-11,000 CNY/kW (1,100-1,210 EUR/kW).[37] The fuel cost of running the Jiangsu solid biomass combustion power plant is estimated at 315 CNY/tonne (35 EUR/tonne) and the levelised generation cost of the plant is estimated at 900 CNY/MWh (99 EUR/MWh).[38] For

[33] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[34] Wind Blowing off Shangai, Offshore.biz, August 2010. Available at <www.offshorewind.biz/2010/08/10/wind-blowing-to-shanghai-china/>.
[35] Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf.>.
[36] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[37] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[38]尹成杰委员：尽快实行全国统一的生物质发电上网电价 (Biomass Price Required), August 2009. Available at <npc.people.com.cn/GB/9933131.html>.

feedstock, the 25-MW NBE Shanxian solid biomass combustion plant, which consumes 150 to 200 kt (kilotonnes) of agricultural residue a year, paid 150 CNY/t for straw residue coming directly from agriculture. The destination price is estimated to be between 200 to 300 CNY/t, including costs for collection, processing and transportation.[39]

Biomass gasification has great potential in China because of the availability of a large amount of dry waste wood. The first biomass gasification project was a 5.5-MW project developed in 2006, and by the end of 2008 four additional biomass gasification projects, each between 5 and 10 MW in capacity, and totalling 18 MW, were developed and there are no immediate plans for an increase in capacity. The investment cost of a biomass gasification plant was estimated at 6,000 CNY/kW (660 EUR/kW) in 2008.[40]

The government of China is also trying to increase the use of municipal solid waste (MSW) for power production. In 2002, 1 per cent of MSW was used for energy production; the 2030 target is for 30 per cent of MSW to be used. The Asian Development Bank has disbursed USD 200 million to China Everbright International to develop MSW-fired power plants.[41] The largest player in the Chinese biomass sector is National Bio Energy (NBE), a joint venture between the State Grid Corporation of China and Dragon Power. NBE developed the first large-scale biomass power project, the NBE Shanxian project, using Danish technology, and in 2009 it was developing 30 new biomass power projects. NBE is also investing in projects in Europe.[42]

3.3.5.2 Biogas

The installed generating capacity of landfill gas and biogas increased dramatically in recent years (see Table 3.10). Most of the large-scale biogas projects, particularly landfill gas projects, were developed under the CDM scheme.

Table 3.10: Development of landfill gas and biogas generating capacity in China from 2005 to 2008 (MW)

Description	2005	2006	2007	2008	CAGR 2005-2008 (%)
Landfill gas	5	13	32	45	108
Biogas	30	86	125	173	79

Source: Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

Biogas projects are usually small and off grid. The government has promoted the use of small household biogas digesters to supply energy in rural areas. Every year, the government spends CNY 1 billion to develop rural biogas projects,[43] and by the end of 2008, 32 million households had built small-scale biogas digesters to meet their own energy requirements. The

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[39] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[40] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[41] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[42] National Foreign Trade Council, China's Promotion of the Renewable Electric Power Equipment Industry, March 2010. Available at < www.nftc.org/default/Press Release/2010/China Renewable Energy.pdf>.
[43] Asia Pacific Energy Research Council, APEC Energy Review 2009, March 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

government projected that 40 million rural households (160 million people) will use biogas as their main fuel by 2010, and 80 million households (300 million people) will do so by 2020.[44] Agricultural effluent projects also tend to be small, between 80 and 200 kW, and off grid. A farm with10,000 pigs, which is considered to be a large operation in China, would be able to develop a plant of only 100 kW. Such farms tend to be located in more remote areas, which makes it difficult to connect plants to the grid.[45]

To facilitate development of large-scale biogas power plants, the government has set targets, as shown in Table 3.11. In September 2009, GE completed construction on a 3-MW biogas plant, the largest in China. The plant is located at the Minhe Animal Husbandry Facility, a meat processing plant in the Shangdong province. The company's 23 chicken farms supply the effluent. The power plant consumes 300 tons of animal effluent and 500 tonnes of wastewater every day. The power produced at the plant is used mainly for the processing plant, and the surplus is fed into the public power grid for sale. The project will earn CDM credits.[46]

Table 3.11: Government targets for large-scale biogas power plants for 2010 and 2020

Description	2010	2020
Number of large-scale agricultural effluent biogas projects	4,700	10,000
Number of large-scale industrial effluent biogas projects	1,600	6,000
Amount of biogas produced (billion m^3)	4	14
Total installed capacity (GW)	1	3

Source: Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf.>.

3.3.6 Solar Energy

3.3.6.1 Solar PV

Although China has one of the largest solar cell and module manufacturing industries in the world, it has seen only a slow increase in the installed capacity of solar PV power (see Table 3.12). For example, in 2008, while 2,600 MW of solar cells were produced in China, only 50 MW was installed in China, increasing installed capacity to 150 MW. The government's solar PV power development targets for 2010 and 2020 are given in Table 3.13.

Table 3.12: Changes in installed solar PV power capacity in China from 1995 to 2008 (MW)

Description	1995	2000	2002	2004	2006	2007	2008	CAGR 1992-2008 (%)
Accumulated capacity	6.6	19.0	45.0	65.0	80.0	100.0	150.0	27.2

Source: Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

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[44] CREIA, Renewable Energy Status and Policy in China, 18 November 2009. Available at <www.iea-retd.org/files/091118_CHINA_policies.pdf>.
[45] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[46] GE, GE Power's China's Largest Biogas Plant, September 2009. Available at <www.gereports.com/ge-powers-chinas-largest-chicken-waste-biogas-plant/>.

In 2009, the government began promoting the installation of building-integrated and roof-top (building-attached) PV systems by changing the building code and introducing support programmes.[47] As noted earlier, through the Solar Roofs Programme, the government offers investment incentives of 17 CNY/W (1.87 EUR/W) for building-integrated PV systems, and 13 CNY/W (1.43 EUR/W) for building-attached PV systems with a capacity of 50 kW or larger in 2010.[48] It is estimated that the government's subsidy covers the retail costs of the modules, requiring the developer to pay only for their installation.[49] As of August 2009, 111 projects totalling 91 MW were approved for the subsidy.[50]

Table 3.13: Solar PV power development targets in China for 2010 and 2020 (cumulative installed capacity in MW)

Description	2010	2020
Rural electrification systems	150	300
Grid-connected building-integrated systems	50	1,000
Large-scale grid-connected systems	20	200
Commercial applications (communications, signalling, etc.)	30	100
Total	250	1,600
CAGR required from 2008 level (%)	29.1	21.8

Source: Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf>.

For larger ground-based solar power installations, the government has introduced the Golden Sun Programme. Under the programme, the government finances 50 per cent of the construction costs for solar PV installations over 300 kW (70 per cent if the installation is for off-grid applications) for a maximum of 20 MW in each province. In November 2009, the government announced that 294 projects, totalling 642 MW, had been approved. Of the total, 232 projects (290 MW) were at industrial and commercial locations for self-consumption; 27 projects (46 MW) are designed to supply power to off-grid areas; and 35 projects (360 MW) were to be connected to the main power grid.[51]

The US solar power developer First Solar was awarded the contract to construct the first large-scale solar PV power plant in Inner Mongolia. Construction on the project, which is expected to total 2,000 MW and will be the largest in the world when completed, is due to start in June 2010, with the final phase expected to be completed by 2019.[52]

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[47] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[48] Ministry of Finance, 关于组织申报2010年太阳能光电建筑应用示范项目的通知(Declaration of 2010 of Solar Roofs), March 2010. Available at <jjs.mof.gov.cn/zhengwuxinxi/tongzhigonggao/201004/t20100415_287576.html>.
[49] Beijing Energy Network, Dawn of a New Era. Available at <greenleapforward.com/2009/03/27/dawn-of-a-new-era-the-gansu-solar-concession-and-landmark-solar-roofs-program/>.
[50] Ministry of Finance, The Government 1.27 billion for Solar Roofs Programme, August 2009. Available at <jjs.mof.gov.cn/zhengwuxinxi/gongzuodongtai/200909/t20090914_207328.html>.
[51] Ministry of Finance, 加快实施"金太阳"示范工程 促进光伏发电产业发展 (Accelerating the Implementation of the Golden Sun Programme), 13 November 2010. Available at <www.mof.gov.cn/pub/mof/zhengwuxinxi/caizhengxinwen/200911/t20091113_232469.html>.
[52] First Solar, First Solar to Team With Ordos City on Major Solar Power Plant in China Desert, September 2009. Available at <investor.firstsolar.com/phoenix.zhtml?c=201491&p=irol-newsArticle&ID=1328913&highlight=>.

3.3.6.2 Concentrated Solar-thermal Power

As of September 2010, no concentrated solar-thermal power (CSP) projects had been completed or were under construction. The government has a target of 50 MW of CSP by 2010, and 200 MW by 2020.[53]

In January 2010, the American CSP developer eSolar signed a USD 5 billion deal to assist Shandong Penglai Electric Power Equipment Manufacturing Co. with building 2,000 MW of CSP systems. The first solar plant under the deal will be a 92 MW plant in Yulin city in the central province of Shaanxi and construction is expected to start in late 2010.[54] However, there are reports that the government is sceptical of the technology because of a lack of water supplies required to produce steam in the areas envisioned for the development.[55]

3.3.7 Small Hydro

In China, small hydro is defined more by the location or purpose than by size. However, generally anything under 50 MW is considered small hydro. At the end of 2008, a total of 51,300 MW of small hydro was installed in China, generating 155.6 TWh of electricity (see Table 3.14) or 27.0 per cent of total hydropower generation. Small hydro is encouraged for rural electrification. Almost three-quarters of small hydropower is concentrated in two regions, the Yangtze River basin and the western part of China (including Tibet and Zinjiang).[56] Small hydropower is projected to increase to 75 GW by 2020, after which few suitable locations will be left.[57]

Table 3.14: Changes in small hydropower capacity and output in China from 2001 to 2008

Description	2001	2002	2003	2004	2005	2006	2007	2008	CAGR 2001-08 (%)
Installed capacity (MW)	26,262	28,489	30,833	34,661	38,534	43,184	47,389	51,300	10
Annual output (TWh)	87.1	94.7	97.9	97.8	120.9	136.1	143.7	155.6	8.6

Source: Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

3.3.8 Geothermal

High temperature resources suitable for power production are concentrated in the less-populated Tibet Autonomous Region and the provinces of Western Yunnan and Western

[53] Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf>.
[54] James Murray, eSolar secures deal for China's largest concentrated solar power plant: Google-backed solar giant continues global expansion drive with Chinese technology licensing deal, BusinessGreen, 12 January 2010. Available at <www.businessgreen.com/business-green/news/2255967/esolar-secures-deal-china>.
[55] Keith Bradsher, China Tries a New Tack to go Solar, New York Times, 8 January 2010. Available at <www.nytimes.com/2010/01/09/business/energy-environment/09solar.html>.
[56] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.
[57] CREIA, Renewable Energy Status and Policy in China, 18 November 2009. Available at <www.iea-retd.org/files/091118_CHINA_policies.pdf>.

Sichuan along the Himalayan Geothermal Belt.[58] There was a total installed capacity of 27.6 MW of geothermal power in China at the end of 2008, all of which was located in Tibet. The largest plant has a capacity of 24 MW.[59] In March 2010, the government announced a plan to expand the existing 24-MW geothermal power plant in Tibet by 6 MW.[60] The government expects that geothermal power will reach 100 MW by 2020.[61]

3.3.9 Marine (Wave/Tidal)

The Jiangxia Tidal Power Station in Zhejiang Province, which was completed in 1972, is the third largest tidal power plant in the world at 3,200 kW.[62] SDE, an Israeli wave power developer, is developing a 1 MW wave power plant in the Guangdong province, which is expected to be completed by the end of 2010. This plant is a part of the first phase of a 10 GW wave power programme planned for the coast.[63]

3.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	**1/5**
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. *A high debt ratio may lead to negative change in the incentive policy for renewable energy*.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

3.4.1 Government Structure

The Communist Party of China is the only political party in China. The president, Hu Jintao, has been in power since 2003 and his term of office will end in 2013. He is not eligible to stand for re-election to the post. China has experienced rapid economic growth in the past

58 Anthony Taylor and Zheng Li, Geothermal Resources in China, January 1996. Available at <www.bl-a.com/ECB/PDFFiles/China1996.PDF>.
59 International Geothermal Association, China. Available at <www.geothermal-energy.org/208,welcome_to_our_page_with_data_for_china.html>.
60 China's Largest Geothermal Power Station to Increase Production, Focus on Tibet, 6 March 2010. Available at <news.xinhuanet.com/english/2010-04/06/content_13307379.htm>.
61 Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf.>.
62 For more information see the website at <www.cresp.org.cn/uploadfiles/73/613/zhejiang.html>.
63 China First System of Planned Marine Energy Project, ArsTechnica, 21 April 2010. Available at <cleantechnica.com/2010/04/21/chinas-1st-system-of-a-giant-10gw-marine-energy-project/>.

decade; however, political freedoms are still limited. Because of the global economic downtown, China's GDP growth rate declined to 8.7 per cent in 2009, compared to 13 per cent in 2007. It is expected to rise to 10 per cent in 2010.[64] No significant change in current renewable power policies is expected.

3.4.2 Government Debt

The IMF estimates China's public debt in 2009 as 18.6 per cent of its GDP, and projects the debt rising to over 20 per cent of GDP in 2010 due to economic stimulus measures. The fiscal deficit in 2009 was 3.0 per cent of GDP, a level projected to continue into 2010, reducing to 2.0 per cent in 2011 due to the end of some stimulus measures.[65]

There is, however, considerable ambiguity over how accurate a picture is painted by official figures for government debt. In particular, these figures do not take into consideration the high levels of municipal borrowing and bond issuance by state-owned firms. Therefore, the total extent of state liabilities could reach nearly 100 per cent of GDP in 2012 if these implicit liabilities are included. According to China's Banking and Regulatory Commission, average local government debt was 97.8 per cent, and there has been concern over delinquent loans to state banks originating from an explosion in local government borrowing. Local government debt-service ratios are projected to hit an average of 26.6 per cent in 2012,[66] and the sector remains acutely vulnerable to an asset-price downturn, because at least 20 per cent of local government revenues on average come from the sale of real estate. Doubts over the ability of local and state entities to service these debts and the systemic risk this implies strongly suggest that they may have to be absorbed into central government balance sheets. This eventuality would likely be associated with stricter rules on local government borrowing and an increase in project financing costs due to scarcer credit.

3.4.3 Targets and Commitments

China is a signatory to the Kyoto Protocol, but as a non-Annex 1 country it does not have an emissions reduction target under the terms of the agreement. In late 2009, as part of the Copenhagen Accord, the government introduced a target to cut the carbon intensity of the economy in 2020 by at least 40 to 45 per cent from their 2005 levels. In addition, the government has a target to meet 15 per cent of primary energy consumption from renewable energy by 2020, up from 9 per cent in 2008. Under the Renewable Portfolio Standard (RPS) regulation, all generators with more than 5 GW of installed capacity are required to source 8 per cent of installed capacity from non-hydroelectric renewable power sources by 2020.

Table 3.15: Chinese government commitments

GHG emissions	A 2020 government target to cut the carbon intensity of the economy by 40 to 45 per cent compared to 2005 levels.[a]
Renewable energy (RE)	A target of 15 per cent of total energy consumption to be met from renewable sources by 2020.[a]
Renewable electricity	8 per cent of total generating capacity to be non-hydro renewables by 2020.[b]

Sources: [a]China Amends Law to Boost Renewable Energy Law, 26 December 2009. Available at <english.gov.cn/2009-12/26/content_1497233.htm>; [b]Medium and Long-Term Development Plan for Renewable Energy in China 2007. Available at <www.chinaenvironmentallaw.com/wp-content/uploads/2008/04/medium-and-long-term-development-plan-for-renewable-energy.pdf.>.

[64] CIA World Factbook: China. Available at <www.cia.gov >.
[65] IMF, Article IV, July 2010. Available at <www.imf.org/external/pubs/ft/scr/2010/cr10238.pdf>.
[66] Chinese Academy of Social Sciences

3.4.4 Public Sentiment

There is strong public support for the development of renewable energy in China. In a 2008 survey conducted by World Public Opinion, 72 per cent responded in favour of utilities supplying an increased amount of renewable energy even if it costs more in the short term.[67] In a similar poll, 80 per cent of young Chinese respondents said they were concerned about global warming, and just over three-quarters of respondents said they expected the government to lead in this area.[68] In another poll, 63 per cent of Chinese respondents said that it was fair for developed countries to force China and other developing countries to reduce carbon emissions.[69]

However, nuclear power continues to be seen as a way for China to develop without increasing emissions, with 63 per cent of respondents in the above-mentioned World Public Opinion poll agreeing that nuclear power should be increased.[70]

3.5 Grid Connection Risk Index

Measure		**Value**	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	**2/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	1	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.	0	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

3.5.1 Functional Separation

China’s main transmission grid is divided into six different grid zones, each owned and operated by a separate transmission system operator (TSO). One company, the State Grid Corporation of China, owns five of the TSOs, and the China Southern Power Grid Corporation owns the other one. Both companies are owned by the state. Table 3.16 details the transmission grid zones.

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67 World Public Opinion, World Publics Strongly Favour Requiring More Wind and Solar Energy, More Efficiency, Even If It Increases Costs, November 2008. Available at <www.worldpublicopinion.org/pipa/articles/btenvironmentra/570.php?lb=bte&pnt=570&nid=&id=>.
68 Xinhua News Agency, China’s Young Favour Sustainable Consumption, 20 August 2007. Available at </news.xinhuanet.com/english/2007-08/20/content_6570747.htm>.
69 GMI, International Poll Shows That People Want Governments to Take Strong Action on Climate Change, 2007. Available at <www.gmi-mr.com/about-us/news/release.php?p=2007-06-05>.
70 World Public Opinion, World Publics Strongly Favour Requiring More Wind and Solar Energy, More Efficiency, Even If It Increases Costs, November 2008. Available at <www.worldpublicopinion.org/pipa/articles/btenvironmentra/570.php?lb=bte&pnt=570&nid=&id=>.

Distribution system operators (DSOs) are generally owned by local prefectures or counties, depending on the size of the area involved. The power sector regulator is the State Electricity Regulatory Commission of China (SERC).[71]

Table 3.16: Transmission grid zones in China

Grid zone/TSO		Location	Total installed capacity involved (2008)
State Grid Corporation of China	Huabei	Beijing, Tianjin, Hebei, Shanxi, and Shandong	129.2 GW
	Dongbei	East Mongolia, Liaoning, Jilin, and Heilongjang	55.8 GW
	Huadong	Shanghai, Jiangsu, Zhejiang, Anhui, and Fujian	164.6 GW
	Huazhong	Jiangxi, Henan, Hubei, Hunan, Chongqing, and Sichuan	154.3 GW
	Xibei	Shaanxi, Gansu, Qinghai, Ningxia, and Xinjiang	47.1 GW
China Southern Power Grid Co	Nanfang Grid Company	Guangdong, Guangxi, Hainan, Guizhou, and Yunnan	128 GW

Source: Asia Pacific Energy Research Centre, Understanding Energy in China: -Geographies of Energy Efficiency, September 2009. Available at <www.ieej.or.jp/aperc/2009pdf/APERC_China_2009_rev.pdf>.

3.5.2 Grid Capacity

Lack of available grid capacity is seen as a major impediment to the development of large-scale wind power projects. For example, in north-eastern China, where the majority of wind power development is taking place, new wind power projects with a total capacity exceeding 13 GW have been approved by the government and are expected to be completed in 2010; however, the TSO estimates that about 9 GW of capacity can be connected to the grid without major upgrade work.[72]

Grid operators are starting to respond to the increase in renewable power generation and the requirement for reinforcing the grid.[73] They are expanding the networks, particularly the high voltage networks (220 kV and up).[74] However, to meet the government's wind power targets, especially in the remote areas in Xinjiang, Gansu and Inner Mongolia, it will be necessary to build 750 kV or even higher voltage lines or direct current (DC) transmission systems. As it will take a number of years to finish these networks, wind power development in these remote regions could slow down.[75]

3.5.3 Access and Connection Cost

Power plants with a capacity of 50 MW or above are connected to the transmission network, while others are connected to the distribution network. Under China's Renewable Energy Law, priority grid access is given to renewable power installations, and once they are

[71] Asia Pacific Energy Research Centre, Understanding Energy in China: -Geographies of Energy Efficiency, September 2009. Available at <www.ieej.or.jp/aperc/2009pdf/APERC_China_2009_rev.pdf>.
[72] China Eyes 90 GW, Reuters, 27 April 2010. Available at <www.reuters.com/article/ idUSTRE63Q23V20100427?loomia_ow=t0:s0:a49:g43:r5:c0.117647:b33463452:z0>.
[73] REN21, Recommendations for Improving the Effectiveness of Renewable Energy Policies in China, October 2009. Available at <www.ren21.net/pdf/Recommendations_for_RE_Policies_in_China.pdf>.
[74] Asia Pacific Energy Research Council, APEC Energy Review 2009, March 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.
[75] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

connected to the grid, network operators are obliged to take all output regardless of demand.[76] Developers have reported, however, that the grid operators do not always properly follow the requirement for priority connections. As a result, there is still a large backlog of renewable power projects, particularly wind power projects, waiting for grid connection.[77] Grid operators are also required to build the connection to the renewable power plant and to invest in any grid reinforcement work necessary. Thus developers pay a ‘shallow connection charge’ instead of a ‘deep connection charge’.[78]

3.6 Planning Permission Risk Index

Measure		Value	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**1/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

3.6.1 Complexity and Expected Timescales

Projects of 50 MW or larger in capacity have to be approved by the central government. For projects of less than 50 MW, approval is given by the regional governments.

China became one of the first countries to integrate RE development into the planning system, when official plans to use renewable energy for rural electrification were launched in 1985. There are reports, however, that the development approval process can be heavily bureaucratic and permits are required from a number of authorities, each of which has its own policies and rules, especially for installations in urban areas.[79]

[76] Global Wind Energy Council, Global Wind 2009 Report, March 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.
[77] Federico Caprotti, China’s Cleantech Landscape: The Renewable Energy Technology Paradox, Sustainable Development Law and Policy, Spring 2009. Available at <eprints.ucl.ac.uk/16051/1/16051.pdf>.
[78] Global Wind Energy Council, Global Wind 2009 Report, March 2010. Available at <www.gwec.net/fileadmin/documents/Publications/Global_Wind_2007_report/GWEC_Global_Wind_2009_Report_LOWRES_15th. Apr..pdf>.
[79] Ren21 and CREIA, Background Paper: Chinese Renewable Energy Status Report, October 2009. Available at <www.ren21.net/pdf/Background_Paper_Chinese_Renewables_Status_Report_2009.pdf>.

3.6.2 Local Opposition and Procedural Improvements

There is very little information available with respect to local opposition, except regarding large-scale hydropower projects such as the Three Gorges Dam. Renewable power developers have not publicly expressed concern about planning procedures.

3.7 Conclusion

A strong demand for electricity has returned as the global recession has ended, and a substantial increase in power demand is projected for the next 20 years. There is large potential for renewable energy exploitation in China, particularly for wind and solar power, and the government has introduced ambitious targets for renewable energy deployment.

In recent years, China has seen a large increase in the deployment of renewable power systems, especially large wind power. The government's 10-GW 2010 target for wind power was met in 2007, and at the end of 2009 there was over 25 GW of onshore wind power connected to the power grid.

Other forms of renewable power have been slower to develop, but the government is starting to promote solar and marine energy. Solar power, which has been primarily used for off-grid rural electrification until recently, is now eligible for large investment subsidies for utility-scale projects. Many utility-scale solar power projects, both PV and CSP, are planned and construction is expected to start in 2010. Offshore wind power and wave and tidal power projects are also expected to come online in 2010, and the coastal provinces are preparing plans for further development of offshore renewable energy.

Developers have indicated, however, that there are concerns about the availability of grid capacity. Grid operators are investing in upgrading the grid, but this investment is expected to take a number of years to be completed, in which case some large projects, especially large wind and solar power plants located in remote regions, may be delayed. There are also complaints about excessive bureaucracy when applying for planning permission in urban areas and continuing doubts as to the fallout from high local government indebtedness.

Chapter 4: India

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
A well-priced feed-in tariff regime is likely to see the renewable sector experience significant growth in the years 2010-2020.	**5/5**

2. Power Market Opportunities Index	Value
The growth rate of India's electricity consumption is extremely high, and dependence on imported coal for generation is rising. Nuclear power is still seen as part of India's energy strategy.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind, Small hydro
Emerging Technologies Technologies that have growth potential in the country.	Solar power, Offshore wind

Risk Indices

4. Political Will Risk Index	Value
The public are generally positive about renewable energy, while the incumbent political party has a good track record in increasing renewable deployment.	**1/5**

5. Grid Connection Risk Index	Value
Grid quality is low in some rural areas but the transmission authorities have embarked on an ambitious investment drive which is likely to improve the situation. Reinforcement costs are not borne by developers.	**1/5**

6. Planning Permission Risk Index	Value
Serious delays in planning are not common in India and there are a multitude of government and state investment agencies to facilitate foreign investment in renewable power and to coordinate and oversee renewable development in India.	**1/5**

4.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.*	3	**5/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	1	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.*	1	

4.1.1 Operating Incentives

4.1.1.1 Federal Feed-in Tariffs

In 2009, the federal Central Electricity Regulatory Commission (CERC) issued guidelines to states for developing feed-in tariffs (FIT) systems. The guidelines are as follows:

- All renewable power technologies will be included
- The rates will last for 13 years except:
  - Solar PV and solar thermal: 25 years
  - Small hydro (≤5 MW): 35 years
- The final tariffs will be decided by the state power regulators
- The FIT rates will be reviewed after one year in the case of solar power, and three years for other renewable power.[1]

CERC released guideline FIT rates which the states are free to adapt (see Table 4.1). For fiscal years (FY) 2010/2011 (1 April to 31 March), CERC introduced new base tariffs, and then reduced them on the basis of a perceived downward trend in investment costs. As of July 2010, several states including Rajasthan have followed and to a certain extent adopted CERC regulations for their new tariff structure, and Madhya Pradesh, Maharashtra, Jharkhand and Orissa were expected to follow.

To promote inter-state trade in renewable power, CERC is also in the process of setting up a new tradable green certificate system. Generators from one state could therefore sell their power in another state and still receive incentives. India is likely to launch this system near to the end of 2010.[2]

[1] Central Electricity Regulatory Commission, RE Tariff Regulations. Available at <www.cercind.gov.in/Regulations/Final_SOR_RE_Tariff_Regulations_to_upload_7_oct_09.pdf>.

[2] Central Electricity Regulatory Commission, CERC Notifies Tariff Regulations for Green Power, September 2009. Available at <www.cercind.gov.in/2009/September09/Press-Release_17.09.09_RE regulations.pdf>.

Table 4.1: The CERC tariff guidelines for states

Description			FY2009/2010	FY 2010/2011			
				Reference tariff	Degression	Total	
			INR/MWh	INR/MWh	INR/MWh	INR/MWh	EUR/MWh[a]
Wind	Locations with wind strength 200-250 W/m^2		5,630	5,070	780	4,290	70.30
Wind	Locations with wind strength 250-300 W/m^2		4,900	4,410	680	3,730	61.12
Wind	Locations with wind strength 300-400 W/m^2		3,750	3,380	520	2,860	46.86
Small hydro	In Himachal/ Uttranchal/ North eastern States	< 5 MW	3,900	3,590	480	3,110	50.96
Small hydro	In Himachal/ Uttranchal/ North eastern States	5-25 MW	3,350	3,060	430	2,630	43.10
Small hydro	In other states	< 5 MW	4,620	4,260	570	3,700	60.63
Small hydro	In other states	5-25 MW	4,000	3,650	510	3,140	51.45
Solar PV			18,440	17,910	2,960	14,950	244.97
Solar thermal-electricity			13,450	15,310	2,460	12,850	210.56
Biomass			3,930-5,520	3,350-4,620	190	3,160-4,430	51.78-72.59
Bagasse			4,800-5,780	3,680-4,860	240-320	3,410-4,590	55.88-75.21

Note: [a]The INR-EUR conversion rate used is EUR 1 = INR 61.02737 (the average over the first six months of 2010).
Source: Central Electricity Regulatory Commission, CERC Notifies Tariff Regulations for Green Power, September 2009. Available at <www.cercind.gov.in/2009/September09/Press-Release_17.09.09_RE regulations.pdf>.

In 2008, the federal government introduced extra incentives for the adoption of wind and solar power by offering an additional premium for power from these sources (see Table 4.2). For wind power, projects up to 49 MW are eligible, and the incentive is in addition to the state-level FIT. For solar power, generators must choose between a state FIT and the federal FIT.

Table 4.2: Federal incentives for wind and solar power generation in India

Technology	INR/MWh	EUR/MWh
Wind power fixed premium	500	8.19
Solar PV variable premium	12,000	196.63
Concentrated solar-thermal power variable premium	10,000	163.86

Source: Ministry of New and Renewable Energy, Major Initiatives in 2008. Available at <mnes.nic.in/press-releases/press-release-29122008.pdf>.

Under the federal incentive system for wind power, the premium will be available for between 4 and 10 years, with a maximum of 1.55 million INR/MW (25,000 EUR/MW) a year and 6.2 million INR/MW (102,000 EUR/MW) altogether. The incentive is available until a total of 4,000 MW is installed in the country.[3]

[3] Ministry of New and Renewable Energy, GBI Scheme. Available at <www.mnre.gov.in/gbi-scheme.html>.

For both solar PV and concentrated solar-thermal power, the amount of the premium that the federal government will give to the developer will be based on a power purchase agreement (PPA) that the developer signed with the utility.[4] A maximum capacity of 10 MW per Indian state and 5 MW per developer will be eligible for support under this scheme.

4.1.1.2 State Operating Incentives

By April 2010, 19 of India's 29 states had introduced state-level quota systems for renewable electricity production to meet federal targets (see Table 4.3). These quota systems are not connected to a market tradable system, although it is expected that they would be if any federal quota system were introduced.

Table 4.3: Renewable electricity quotas in selected states in India

State	Renewable energy purchase obligation
Andhra Pradesh	Minimum 5 per cent (0.5 per cent for wind)
Madhya Pradesh	10 per cent
Gujarat	2008/09 – 2009/10: 2 per cent
Rajasthan	2010/11: 8.5 per cent
Orissa	2011/12: 5 per cent and 0.5 per cent increase every year till 2015/16
Maharashtra[a]	2010/11: 6 per cent, 2011/12: 7 per cent, 2012/13: 8 per cent, 2013/14, 2014/15, 2015/16: 9 per cent
Tamil Nadu	2009/10: 10 per cent
Karnataka	7 - 10 per cent
Haryana	2008/09: 5 per cent
West Bengal	2010/11: 8.3 per cent , 2011/12: 10 per cent
Kerala	2 per cent
Chattisgarh	2009/10: 10 per cent
Assam	2009/10: 5 per cent, 2012/12: 10 per cent, 2015/16: 15 per cent
Jharkhand	2010/11 – 2012/13: 5 per cent
Punjab	2010/11: 8.5 per cent, 2011-12: 9.5 per cent

Source: New Energy India, Policy Overview. Available at <www.newenergyindia.org/Policy Page.htm>; [a] Maharashtra Electricity Regulatory Commission. Available at <www.mercindia.org.in/pdf/Order%2058%2042/Final_MERC(RPO-REC)_Regulation_2010_English.pdf>.

4.1.1.2.1 Wind Power

At the end of 2009, 11 states were operating FIT systems for wind power. The FIT rates for wind-generated electricity vary from state to state, and range from 3,390 to 4,500 INR/MWh. Transmission costs are only paid for a percentage of the electricity fed into the grid; this percentage ranges from 2-12 per cent depending on the state (see Table 4.4). For projects under 49 MW, the federal incentive can be added (see Table 4.2).

[4] Ministry of New and Renewable Energy, SPG Scheme. Available at <www.mnre.gov.in/pdf/guidelines_spg.pdf>.

Table 4.4: Feed-in tariff rates for wind power in selected states in India

State	Feed-in tariff rates		Transmission incentives	Notes
	INR/MWh	EUR/MWh		
Tamil Nadu	3,390	55.55	5 per cent of transmission tariff paid by state	Fixed for 5 years
Gujarat	3,370	55.22	4 per cent of transmission tariff paid by state	Fixed for 20 years
Rajasthan	4,280-4,500	70.13-73.74	10 per cent of transmission tariff paid by state	None
Karnataka	3,400	55.71	2 per cent of transmission tariff paid by state	Fixed for 10 years
Madhya Pradesh	4,030	66.04	2 per cent of transmission tariff paid by state	Reducing by 170 INR/MWh a year for first 4 years
West Bengal	4,000	65.54	300 INR/MWh paid for transmission	This is the price cap
Kerala	3,140	51.45	None	Fixed for 20 years
Maharashtra	3,500	57.35	7 per cent of transmission tariff paid by state	Increasing by 150 INR/MWh per year for 15 years
Andhra Pradesh	3,370	55.22	5 per cent of transmission tariff paid by state	Fixed for 10 years
Haryana	4,080	66.86	2 per cent of transmission tariff paid by state	Increasing by 1.5 per cent from base year of 2007-08
Punjab	3,660	59.97	2 per cent of transmission tariff paid by state	Increase by 5 per cent a year until 2012

Source: Ministry of New and Renewable Energy, Policies Introduced by the State Governments for Wind Power, December 2009. Available at <www.mnre.gov.in/annualreport/2009-10EN/Chapter%206/chapter%206_1.htm>.

4.1.1.2.2 Solar PV

Apart from the federal FIT for solar power there are few state-level support systems. The state government in Orissa, however, is giving an additional 3,000 IRN/MWh to a 5-MW project under development (in addition to the federal 12,000 IRN/MWh). The total compensation for the project would thus be 15,000 IRN/MWh (245.79 EUR/MWh).[5]

In November 2009, the federal government approved the 'Jawaharlal Nehru National Solar Mission' (JNNSM) which aims at the development and deployment of solar energy in the country to achieve parity with the grid power tariff by 2022. The initiative has proposed a FIT rate of 17,910 INR/MWh (293.47 EUR/MWh) for solar PV power plants for 20 years. The government has also approved the implementation of the first phase of the Jawaharlal Nehru National Solar Mission during 2009-2013 and the target to set up 1,000 MW grid-connected solar plants, 100 MW of roof top and small solar plants connected to the low-voltage grid, and 200 MW of off-grid solar applications in the first phase of the Mission, which will run till March 2013.[6]

[5] Orissa Electricity Regulation Authority. Available at <www.orierc.org/Orders/2009/C-97-2009.pdf>.
[6] Ministry of New and Renewable Energy, Jawaharlal Nehru National Solar Mission. Available at <mnre.gov.in/pdf/mission-document-JNNSM.pdf>.

4.1.1.2.3 Solid Biomass

As of 31 December 2009, 12 states were operating a FIT system for biomass power (see Table 4.5). In some states, the renewable power generator is not allowed to sell the output to a third party and must consume it on site.

Table 4.5: Feed-in tariff systems in selected states in India for biomass power generation

State	FIT rate		Electricity sales to third parties	Other incentives
	INR/MWh	EUR/MWh		
Andhra Pradesh	2,630	43.10	Not allowed	N/A
Karnataka	2,850	46.70	Allowed	2.5 million INR/MW (41,000 EUR/MW) subsidy, for combined heat and power plants only
Madhya Pradesh	3,330	54.57	Allowed	For 20 years
Chhattisgarh	3,050-3,710	49.98-60.79	Allowed	Electricity duty exempt for first 5 years
Punjab	3,490	57.19	Not allowed	Increases at 3 per cent a year
Maharashtra	3,040-3,430	49.81-56.20	Allowed	50 per cent cost of interconnector costs to be borne by utility
Haryana	4,000	65.54	Allowed	2 per cent escalation
Rajasthan	3,600	58.99	Allowed	N/A
Tamil Nadu	3,150	51.62	Not allowed	Fixed for 3 years
Gujarat	3,000	49.16	Allowed	N/A
Kerala	2,800	45.88	Not allowed	50 per cent cost of interconnector costs to be borne by utility
Uttar Pradesh	2,980	48.83	Allowed	N/A

Source: Ministry of New and Renewable Energy, Policies Introduced by the State Governments for Wind Power, December 2009. Available at <www.mnre.gov.in/annualreport/2009-10EN/Chapter per cent206/chapter per cent206_1.htm>.

4.1.2 Investment Support

4.1.2.1 Wind Power

Import taxation on wind turbines and battery chargers up to 30 kW is levied at only 5 per cent instead of the usual 30 per cent. An excise tax reduction exists for wind power systems and their components. In some states, there is a reduction or exemption on sales tax for components for wind power generation. Accelerated depreciation of 80 per cent of the project cost is also available in the first year.[7]

[7] Wind Power India. Available at <www.windpowerindia.com/govtcentinc.html>.

4.1.2.2 Solar

A capital grant is available for all types of captive solar systems equivalent to 30 per cent of the government's estimated benchmarked cost for systems without battery storage. In 2010 this was fixed at INR 90 (EUR 1.48) per watt of installed capacity for systems with battery storage, and INR 70 (EUR 1.15) for systems without battery storage. For solar thermal projects in remote areas of India, such as Lakshadweep and the Andaman and Nicobar islands, this grant rises to 60 per cent of the benchmarked cost.

Soft loans with an annual interest rate of 5 per cent are available from IREDA for the debt component of a solar project's financing.

4.1.2.3 Biomass

Biomass receives the following incentives:

- Accelerated depreciation (80 per cent in the first year for certain co-generation components)
- Income tax exemption (5 year tax exemption, 30 per cent reduction for the following 5 years)
- Concessional customs and excise duty exemption for machinery and components for initial setting up of projects
- In certain states, there is an exemption on the general sales tax.

There are additional incentives for off-grid systems.[8]

4.1.2.4 Grants

Investment grants for wind power projects are available in the states of Tamil Nadu, West Bengal, Gujarat and Rajasthan.[9] The subsidy usually amounts to a certain percentage of project costs (generally 15-30 per cent) with an upper limit, for example INR 30 million (EUR 492,000) for special category states such as the Northeast Region, Sikkim and Uttaranchal, and INR 25 million (EUR 410,000) for other states.[10] In addition, exemption on electricity tax is often offered for five years.

Off-grid solar power facilities such as solar-home-systems, solar street lighting and mini-grids are supported by the federal government's Solar-Photovoltaic Programme. The programme differentiates between two kinds of support depending on location: facilities in India in general for which up to 50 per cent of capital costs are covered; and facilities in the north-east, including Sikkim, and areas that are not as wealthy as others, known as special areas, for which up to 90 per cent of capital costs are covered. As part of the solar PV-programme, solar PV water pumping systems are also supported. The cash subsidies are for non-commercial enterprises only. The support also encompasses low interest loans, and the maximum amount for a loan is 90 per cent of the system after deducting the subsidy. The loans can have a duration of up to five years, and operate on an interest rate of 5-7 per cent.

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[8] Ministry of New and Renewable Energy. Available at <www.mnre.gov.in>.
[9] For information see the Ministry of New and Renewable Energy website. Available at <mnes.nic.in> and the Indian Renewable Energy Development Agency at <www.ireda.in/incentives.asp>.
[10] Ministry of New and Renewable Energy, CFA Finance Available. Available at <www.mnre.gov.in/cfa-schemes-programmes.htm>.

Table 4.6 outlines the financial assistance offered by the central government under the solar PV programme.

The National Biogas and Manure Management Programme support biogas facilities at the household level for the production of organic fertilizers. Whilst the support is limited to a maximum of INR 2,100 (EUR 34.41) per facility, exceptions are made to allow subsidies of up to INR 11,700 (EUR 191.72) in the north-eastern states, as well as for certain castes and regions.[11]

The Indian Renewable Development Agency also offers soft loans to developers.[12] Companies receive a tax holiday for the first 10 years of operation and import duties on capital goods are waived for projects over 1,000 MW.[13]

Table 4.6: Central government financial assistance provided in India for solar PV

Solar PV	Subsidy
Lanterns	INR 2,400 for the northeast and special areas; 0 for other
Home lighting systems	INR 4500 to 8,600 for NE and special areas, and INR 2500 to 4,800 for other areas, depending on model
Street lighting systems	INR 17,300 for NE and special areas INR 9,600 for other areas
Standalone power plant of capacity >1 kW	2,25,000 INR/kW for NE and special areas IRN 1,25,00 INR/kW for other areas
Standalone power plant of capacity >10 kW	2,70,000 INR/kW for NE and special areas 1,50,000 INR/kW for other areas
Solar PV applications in urban areas:	
Streetlight control systems	25 per cent of cost subject to a max. of INR 5000
Street/public garden lights (74 or 75 W modules)	50 per cent of cost subject to a max. of INR 10,000 INR 12,000 for 11 W and 18 W rated lights, respectively
Power packs (maximum 1 kW module)	50 per cent of cost subject to a maximum of 100,000 INR/kW.

Source: Ministry of New and Renewable Energy, CFA Finance Available. Available at <www.mnre.gov.in/cfa-schemes-programmes.htm>.

[11] India Development Gateway, National Biogas and Manure Management Programme. Available at <www.indg.in/rural-energy/schemes/national-biogas-and-manure-management-programme-nbmmp>.
[12] See the website at <www.ireda.in/incentives.asp>.
[13] Investment Commission of India, Power. Available at <www.investmentcommission.in/power.htm>.

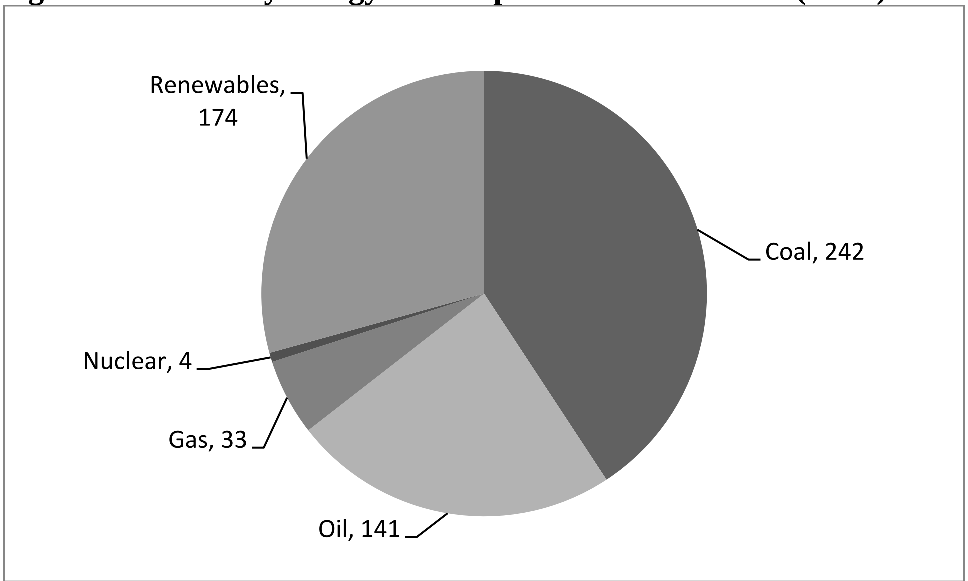
4.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**4/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	2	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

4.2.1 Energy Consumption

Primary energy consumption in India was 594 million tonnes of oil equivalent (Mtoe) in 2007. From 318 Mtoe in 1990 to 2007, primary energy consumption has had a compound annual growth rate (CAGR) of 3.8 per cent. Coal and renewables (primarily biomass) provided the bulk of primary energy consumption (see Figure 4.1). Under the IEA's baseline 'business-as-usual' scenario, primary energy consumption is projected to increase to 901 Mtoe by 2020, representing a CAGR of 3.3 per cent from 2007 levels.[14]

Figure 4.1: Primary energy consumption in India in 2007 (Mtoe): Total 594 Mtoe



Source: IEA, World Energy Outlook 2009.

India's production of primary energy has been increasing in the last four years, but the only sector experiencing marked growth has been coal and lignite due to large domestic reserves. However, natural gas and petroleum production has remained stagnant, with the increase in

[14] IEA, World Energy Outlook 2009.

demand being met with imports. In 2007, 32 per cent of consumption was met with imports, primarily petroleum products.[15]

Final energy consumption amounted to 391 Mtoe in 2007. From 251 Mtoe in 1990 to 2007, final energy consumption had a CAGR of 2.6 per cent. Final energy consumption is projected to increase to 589 Mtoe by 2020 under the IEA's baseline 'business-as-usual' scenario, which would represent a CAGR of 3.2 per cent from 2007 levels.[16]

4.2.2 Electricity Sector

In 2009/10 peak demand in India was 119,166 MW, an 8.5 per cent increase from 2008/09. In 2009/10, there was only 104,009 MW of capacity available to meet peak demand, a capacity deficit of 12.7 per cent. As can be seen from Table 4.7, most regions in India are suffering from capacity deficit—a fact which is likely to persist into 2011. There are however signs that the situation is improving, with the all-India peak deficit shrinking to 12.1 per cent in 2010/11 despite a projected increase in peak demand to 126,951 MW, a 6.5 per cent increase from 2009/10.

Table 4.7: Projected peak demand and capacity deficit in India in 2010/11

State	Peak demand (MW)	Peak availability (MW)	Capacity deficit (MW)	Deficit (%)
Chandigarh	335	254	-81	-24.2
Delhi	4,580	5,170	590	12.9
Haryana	6,390	4,410	-1,980	-31.0
Himachal Pradesh	1,180	1,670	490	41.5
Jammu & Kashmir	2,300	1,610	-690	-30.0
Punjab	9,900	7,420	-2,480	-25.1
Rajasthan	7,200	6,440	-760	-10.6
Uttar Pradesh	10,900	7,690	-3,210	-29.4
Uttarakhand	1,450	1,360	-90	-6.2
Total: Northern Region	40,000	33,220	-6,780	-17.0
Chattisgarh	3,275	2,579	-696	-21.3
Gujarat	10,246	9,277	-969	-9.5
Madhya Pradesh	7,800	6,420	-1,380	-17.7
Maharashtra	18,700	14,219	-4,481	-24.0
Daman & Diu	326	285	-41	-12.6
D.N. Haveli	576	543	-33	-5.7
Goa	507	436	-71	-14.0
Total: Western Region	40,210	34,732	-5,478	-13.6
Andhra Pradesh	12,894	11,093	-1,801	-14.0
Karnataka	7,855	6,546	-1,309	-16.7
Kerala	3,445	2,973	-472	-13.7
Tamil Nadu	11,282	9,751	-1,531	-13.6
Puducherry	335	293	-42	-12.5
Total: Southern Region	34,224	28,450	-5,774	-16.9
Bihar	2,250	1,631	-619	-27.5
DVC	2,385	4,908	2,523	105.8
Jharkand	1,180	1,189	9	0.8
Orissa	3,850	3,916	66	1.7
West Bengal	6,483	6,098	-385	-5.9

[15] Ministry of Statistics and Programme Implementation, Energy Statistics 2010. Available at <mospi.nic.in/Mospi_New/site/inner.aspx?status=3&menu_id=160>.
[16] IEA, World Energy Outlook 2009.

Sikkim	120	157	37	30.8
Total: Eastern Region	16,202	16,568	366	2.3
Arunachal Pradesh	140	132	-8	-5.7
Assam	1,000	940	-60	-6.0
Manipur	130	115	-15	-11.5
Meghalaya	465	294	-171	-36.8
Mizoram	95	82	-13	-13.7
Nagaland	99	92	-7	-7.1
Tripura	151	140	-11	-7.3
Total: North-Eastern Region	1,957	1,679	-278	-14.2
Total: All India	126,951	111,533	-15,418	-12.1

Source: Central Electricity Authority, Load Generation Balance Report 2010-11. Available at <www.cea.nic.in/god/gmd/lgbr_report.pdf>.

Total power consumption from grid-connected customers in India in 2008/09 was 550.23 TWh, a 9.88 per cent increase from the year before. From a total consumption of 316.60 TWh in 2000/01, consumption has increased at a CAGR of 8.2 per cent.[17]

Table 4.8 sets out projections for future increases in India's power consumption and peak demand in the main electricity administrative regions between 2012 and 2022. In general, consumption and peak demand are expected to more than double by 2022. Based on these projections, India is likely to need 189.4 GW of additional capacity just to meet this extra peak demand, and 250 GW, if a 20 per cent reserve capacity margin is to be operated.

Table 4.8: Projections for power consumption and peak demand in India to 2022

Area	Consumption (GWh)			Peak demand (MW)		
	2012	2017	2022	2012	2017	2022
Northern Region	294,841.3	411,513.2	556,767.6	48,136.9	66,582.9	89,912.8
Western Region	294,859.7	409,805.0	550,021.7	47,108.4	64,348.7	84,778.1
Southern Region	253,443.0	380,068.2	511,658.9	40,367.1	60,432.6	80,485.0
Eastern Region	111,802.3	168,941.7	258,215.9	19,088.4	28,400.9	42,711.6
Northeastern Region	13,328.5	21,143.3	36,997.0	2,536.6	3,759.8	6,179.9
All India total	968,274.8	1,391,471.3	1,913,661.2	157,237.5	223,524.9	304,067.4

Source: Central Electricity Authority, 17th Electric Power Survey of India. Available at <www.cea.nic.in/planning/17TH%20EPSR-Highlights.pdf>

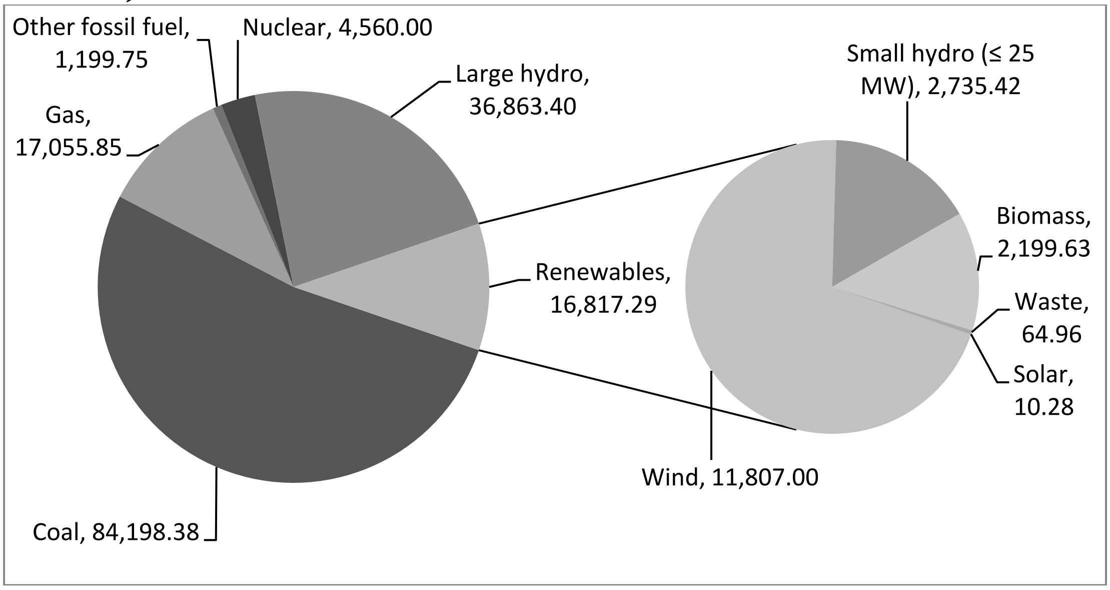
In 2010, the total installed generating capacity in India amounted to 160,694 MW (see Figure 4.2). Approximately 52 per cent of this capacity is owned by the various states, while the large federal-controlled Public Sector Undertakings (PSUs) control 34 per cent. The remaining 14 per cent is owned by the private sector.

In the government's Eleventh Five-Year Plan for 2007 to 2012, it was projected that 78,700 MW of new generating capacity would be added by 2012, of which 19.9 per cent was hydro, 75.8 per cent thermal, and the rest nuclear. In 2007-08 and 2008-09 capacity addition targets were not met, mostly blamed on a shortage of supplies and skilled workers.[18] In 2009/10, there was a target of 14,507 MW to be completed; however, only 9,585 MW was added in that time period. For 2010/11, there is a target of 20,359 MW of new capacity to be

[17] Ministry of Statistics and Programme Implementation, Energy Statistics 2010. Available at <mospi.nic.in/Mospi_New/site/inner.aspx?status=3&menu_id=160>.
[18] India Economic Survey, Energy Infrastructure and Communications, 2010. Available at <www.scribd.com/doc/27465988/India-Economic-Survey-Energy-Infrastructure-Communication-2010>.

completed, 6,105 MW by the private sector with the remainder to be constructed by government-owned utilities.[19]

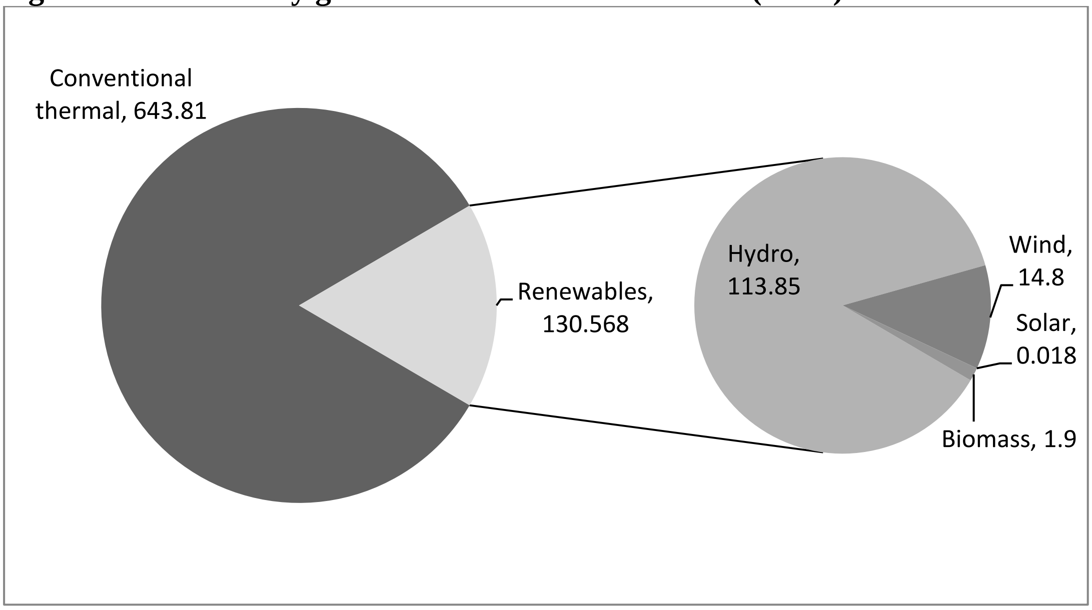
Figure 4.2: Total installed generating capacity in India in 2010 (MW): Total 160,694 MW



Source: Central Electricity Authority, Installed Generating Capacity in India. Available at <www.cea.nic.in>.

In 2008, 774.38 TWh of electricity was generated in India. Conventional thermal generation from gas and coal-fired power plants accounted for over 83 per cent of the electricity generation mix in 2008, with renewable sources (including large hydro), making up the remainder (see Figure 4.3). India also imports approximately 1.5 TWh of hydropower from Bhutan.

Figure 4.3: Electricity generation mix in India in 2008 (TWh): Total 774.38 TWh



Source: EIA international Energy Statistics. Available at <www.eia.doe.gov/emeu/international/contents.html>.

[19] Ministry of Power, Capacity Addition. Available at <powermin.gov.in/Monitering_target/pdf/Capacity_Addition.pdf>.

4.2.3 Nuclear Power

In order to meet the projected increase in demand for power, India has an ambitious nuclear power programme. From 4.6 GW in 2010, the government projects that nuclear power will amount to 20 GW by 2020 and 63 GW by 2032. As of the beginning of 2010, 2.6 GW of new nuclear power was under construction and due for completion by 2012.[20]

4.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Onshore wind, Small hydro
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar power, Offshore wind

4.3.1 Renewable Electricity Generation

Onshore wind power has the largest installed capacity of all renewable power technology in India, with the exception of large hydropower. Wind power has also had the fastest growth in new capacity since 2008 (see Table 4.9).

Table 4.9: Installed generating capacity of renewable power in India from 2008 to 2010 (MW)

Year	Wind	Solar PV	Biomass	Waste	Small hydro (≤25 MW)	Total
31/03/2008	8,757.40	2.12	1,406.63	55.75	2,180.85	12,402.75
31/03/2009	10,242.30	2.12	1,752.33	59.00	2,429.78	14,485.53
31/03/2010	11,807.3	10.12	2,200.33	63.7	2,734	16,815.12
CAGR 2008-2010 (%)	8.2	1.2	0.3	0.1	0.1	0.2

Source: Ministry of Statistics and Programme Implementation, Energy Statistics 2010. Available at <mospi.nic.in/Mospi_New/site/inner.aspx?status=3&menu_id=160>; Ministry of New and Renewable Energy, Grid Interactive Renewable Power During 2009-10. Available at <www.mnre.gov.in>.

4.3.2 Resource Potential

India has considerable scope for solar energy production, receiving a daily average of approximately 520-630 W/m^2 of solar irradiation. A logical site for large scale solar power development would be the 208,110 km^2 of desert areas in Rajasthan and Gujarat.

India's onshore theoretical wind power potential has been estimated at about 48,561 MW, assuming 1 per cent land availability in areas which are suitable for setting up wind farms (sites with wind power greater than 200 W/m^2 at 50 m hub-height), and an assumed 12

[20] World Nuclear Organisation, Country Report: India, September 2010. Available at < www.world-nuclear.org/info/inf53.html>.

hectares per MW in installed capacity.[21] Approximately 24 per cent of onshore wind power potential was developed by 31 March 2010.

More than 540 million tons of crop and plantation residues are produced every year in India and a large portion is either wasted, or used inefficiently. By using these surplus agricultural residues, a conservative estimate is that more than 16,000 MW of grid-quality power could be generated. In addition to this, about 5,000 MW of power could be produced if all 550 sugar mills in the country switched over to modern techniques of cogeneration. Thus the total estimated biomass power potential is about 21,000 MW. Therefore, approximately 11 per cent of biomass potential was exploited as of 31 March 2010.

An estimated 50 million tonnes of solid waste and approximately 6,000 million cubic meters of liquid waste are generated annually in the urban areas of India. This waste could account for an additional 2,600 MW of solid biomass and biogas generating capacity and industrial wastes cold account for an additional 1,300 MW of generating capacity.[22]

India has the capacity to produce 10,600 MW of power from geothermal sources, with promising regions including Himalaya, Sohana, Cambay, Son-Narmada-Tapi, Godavari, and the Barren Island.[23] India's geothermal potential remains almost completely unutilised, however.

With numerous rivers and their tributaries in India, small hydro (≤25 MW) represents a promising source of generating capacity particularly for rural electrification, and 5,415 potential sites for development with an aggregate capacity of 14,292 MW have been identified. Most of the potential sites are river projects in the Himalayan states or on irrigation canals in other states.[24] Approximately 19 per cent of small hydro potential in India was developed by 31 March 2010.

The locations in India with the highest tidal potential are the Gulf of Cambay and the Gulf of Kachchh on the west coast where the maximum tidal ranges are 11 m and 8 m, with average tidal ranges of 6.77 m and 5.23 m respectively. The Ganges Delta in the Sunderbans in West Bengal also has good locations for small scale tidal power development. The maximum tidal range in the Sunderbans is approximately 5 m with an average tidal range of 2.97 m.
The identified economic tidal power potential in India is estimated to be between 8,000 and 9,000 MW with about 7,000 MW in the Gulf of Cambay, 1,200 MW in the Gulf of Kachchh, and less than 100 MW in the Sundarbans.[25]

[21] Ministry of New and Renewable Energy, India's Renewable Energy Sector, Potential and Investment Opportunities. Available at <direc2010.gov.in/India's-RE-Sector-Potential-and-Investment-opportunites-SSM.pdf>.
[22] Ministry of New and Renewable Energy, India's Renewable Energy Sector, Potential and Investment Opportunities. Available at <direc2010.gov.in/India's-RE-Sector-Potential-and-Investment-opportunites-SSM.pdf>.
[23] Chandrasekharam D, Geothermal Energy Resources of India. Available at <www.geos.iitb.ac.in/geothermalindia/pubs/IBC/IBCTALKweb.htm>.
[24] Ministry of New and Renewable Energy, India's Renewable Energy Sector, Potential and Investment Opportunities. Available at <direc2010.gov.in/India's-RE-Sector-Potential-and-Investment-opportunites-SSM.pdf>.
[25] Energy Alternatives India, Tidal Power. Available at <www.eai.in/ref/ae/oce/oce.html>.

Table 4.10 lists the potential for renewable power development in the various states in India.

Table 4.10: Renewable power development potential in the states in India (MW)

Region	Wind	Small hydro	Cogeneration of bagasse	Waste to energy	Total
Andhra Pradesh	8,968	552	200	187	9,907
Arunachal Pradesh	0	1,333	0	0	1,333
Assam	0	213	5	11	229
Bihar	0	213	200	117	530
Chattisgarh	0	706	0	39	745
Goa	0	9	5	0	14
Gujarat	10,645	196	200	172	11,213
Haryana	0	110	0	32	142
Himachal Pradesh	0	2,268	0	2	2,270
Jammu & Kashmir	0	1,411	0	0	1,411
Jharkand	0	207	0	14	221
Karnataka	11,531	643	300	219	12,693
Kerala	1,171	708	10	56	1,945
Madhya Pradesh	1,019	400	25	119	1,563
Maharashtra	4,584	762	1,000	438	6,784
Manipur	0	109	0	3	112
Meghalaya	0	229	0	3	232
Mizoram	0	166	0	2	168
Nagaland	0	196	0	0	196
Orissa	255	295	25	33	608
Punjab	0	390	150	68	608
Rajasthan	4,858	63	10	93	5,024
Sikkim	0	265	0	0	265
Tamil Nadu	5,530	499	350	240	6,619
Tripura	0	46	0	2	48
Uttar Pradesh	0	292	1,000	270	1,562
Uttaranchal	0	1,609	0	7	1,616
West Bengal	0	393	10	221	624
Andaman & Nicobar	0	8	0	0	8
Chandigarh	0	0	0	9	9
Dadar & Nagah Haveli	0	0	0	0	0
Daman & Diu	0	0	0	0	0
Delhi	0	0	0	194	194
Lakshadweep	0	0	0	0	0
Pondicherry	0	0	10	4	14
Total potential	48,561	14,291	3,500	2,555	68,907

Source: Ministry of Statistics and Programme Implementation, Energy Statistics 2010. Available at <mospi.nic.in/Mospi_New/upload/energy_stat_2010_pdf/table_section_1_es10.pdf>.

4.3.3 Levelised Generation Costs

Table 4.11 compares the levelised generation costs for different technologies in the OECD and the Indian federal government-recommended FIT.

Table 4.11: Comparison of feed-in tariff rates in India with levelised generation costs in the OECD (EUR/MWh)

Technology	FIT rate[a]	Levelised generation costs[b]
Onshore wind	46.86-70.30	38-111
Biomass	51.78-72.59	60
Concentrated solar-thermal power	210.56	92
Solar PV	293.47[c]	143-408

Notes: [b]Figures based on a 5 per cent discount rate.
[c]The proposed FIT rate under the Jawaharlal Nehru National Solar Mission is used.
Source: [a]See Incentive Opportunities Index above; [b]IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

4.3.4 Wind Power

4.3.4.1 Onshore Wind Power

India is the fourth-largest producer of wind power in the world, with installed capacity of 11,807 MW as of 31 March 2010. India's wind power programme began in the 1980s, but large-scale deployment is a more recent phenomenon, as the results of government initiatives to increase uptake have borne fruit. The average rate of capacity addition in the years 2005-2009 was 1,543 MW per year.[26] Table 4.12 shows the increase in installed capacity between 2000 and 2009. In 2010/11, an additional 2,200 MW of new capacity is projected to be installed.[27] Of the USD 2.7 billion that was invested in clean energy in India in 2009, 59 per cent, or USD 1.6 billion, was into wind power. Although overall investment in renewable energy slowed in 2009 due to the global economic recession, investment into wind power was the least affected by this slowdown compared to other renewable energy sectors.[28]

Table 4.12: Total installed capacity of onshore wind in India between 2000 and 2009

Capacity	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	CAGR 2000-2009
MW	220	1,456	1,702	2,125	3,000	4,430	6,270	7,845	9,655	10,926	54%

Source: GWEC, Global Wind 2009 Report. Available at <www.gwec.net>.

Apart from the operating and investment incentives offered by the government, an important development by the Centre for Wind Energy Technology has been the production of resource maps which provide information about sites potentially suitable for development. These maps are provided to developers at nominal cost and contain information on the availability of wind, land, grid availability and accessibility of sites.[29]

The theoretical potential of wind power in India is estimated at around 48,000 MW, distributed mainly in the states of Tamil Nadu, Andhra Pradesh, Karnataka, Gujarat, Maharashtra and Rajasthan. Table 4.13 sets out installed capacity and potential of the states in India with recognised wind power potential.

[26] Ministry of New and Renewable Energy, Chapter 6, Annual Report 2010. Available at < www.mnre.gov.in/annualreport/2009-10EN/Chapter 6/chapter 6_1.htm>.
[27] GWEC, Global Wind 2009 Report. Available at <www.gwec.net>.
[28] UNEP SEFI, Global Trends in Sustainable Energy Investment 2010. Available at <sefi.unep.org/>.
[29] Energy Alternatives India, Wind. Available at <www.eai.in/ref/ae/win/win.html>.

Table 4.13: Wind power potential and installed capacity in India at the end of 2009

State	Potential (MW)	Installed capacity (MW)	Unutilised potential (%)
Andhra Pradesh	8,968	122.5	99%
Gujarat	10,645	1,566.5	85%
Karnataka	11,531	1,327.4	88%
Kerala	1,171	27	98%
Madhya Pradesh	1,019	212	79%
Maharashtra	4,584	1,938	58%
Orissa	255	3.2	99%
Rajasthan	4,858	743	85%
Tamil Nadu	5,530	4,304	22%
Total	48,561	10,243.6	79%

Source: Ministry of New and Renewable Energy, Chapter 6, Annual Report 2010. Available at < www.mnre.gov.in/annualreport/2009-10EN/Chapter 6/chapter 6_1.htm>.

India is also developing into a centre of wind power equipment manufacturing. Low labour costs, raw material availability and market potential have contributed to growth in the wind power equipment sector, with 35 manufacturers and turbine suppliers present in the Indian market since the 1990s. The most prominent manufacturer is Suzlon, the fifth largest wind turbine supplier in the world. By 2012-2013 it is estimated that India will have an established manufacturing capability of more than 10,000 MW.[30]

4.3.4.2 Offshore Wind Power

Although India currently has no offshore wind power capacity, investment firms are starting to examine the feasibility of projects in the near future.[31]

4.3.5 Biomass

4.3.5.1 Solid Biomass

Globally, India is the fourth largest producer of biomass power, and it has huge potential for increased production. Approximately 100 biomass power projects with an aggregate capacity of 2,200 MW have been installed in the country.[32]

The availability of biomass in India is estimated at approximately 540 million tonnes per year, covering residues from agriculture, forestry, agro-based industrial plants and plantations. The agriculture residues include rice husk, rice straw, bagasse, sarkanda, groundnut shells, cotton stalks, and mustard stalks. About 70-75 per cent of these wastes are used as fodder, as fuel for domestic cooking and for other economic purposes. Only 140 million tonnes of agro-industrial and agriculture residues can be considered available for power generation.

Projections from the Indian Renewable Development Agency (IREDA) suggest that biomass's share in the electricity generation mix will increase from the current 1.3 per cent to

[30] India Renewable Energy Development Agency, IREDA News April-December 2009. Available at <www.ireda.gov.in/pdf/April-December_2009.pdf>.
[31] MV Ramsurya, India's wind power draws global majors, Economic Times (India), 26 April 2010. Available at <economictimes.indiatimes.com/news/news-by-industry/energy/power/Indias-wind-power-draws-global-majors/articleshow/5857628.cms>.
[32] Ministry of Statistics and Programme Implementation, Energy Statistics 2010. Available at <mospi.nic.in/Mospi_New/site/inner.aspx?status=3&menu_id=160>

approximately 3-5 per cent by 2050. This is a very small contribution compared to the estimated total biomass potential of 15 per cent of primary energy supply by 2050. The main barriers to growth, cited by IREDA, are costs, conversion efficiency, transportation cost, feedstock availability, and a lack of supply logistics.[33]

The seasonal availability of particular types of biomass in India is a cause of cost volatility for biomass-firing plants, which cannot easily be set up to burn different types of feedstocks. Transportation also poses a formidable logistical problem, with the transportation costs of some biomass higher than their fuel value. Procurement of fuel for a biomass plant generally occurs within 50 km of the plant site, limiting the potential locations where these installations can be situated.

There is concern that the green credentials of India's biomass program are being undermined by abuse of the incentive structure on offer. Since the implementation of the Electricity Act of 2003 and the added benefit of the ability to receive CDM credits for biomass-fuelled power plants, many process units, such as textiles, paper, and small chemical and pharmaceutical plants, have attempted to integrate captive biomass-fuelled power plants into their facilities, typically ranging from 5.0 MW to 15.0 MW in capacity. However, due to heavy pressure from promoters and lack of availability of biomass resources, several plants installed in the years 2005 to 2007 have either shut down or are working on fossil fuels.

The government's 11th Five-Year Plan envisions a substantial role for biomass, with targeted additional capacity of 1,700 MW from 2007. India is on course to meet this target if the rate of capacity addition remains the same. Between 2008 and 2009, an additional 346 MW of capacity was commissioned. Recently commissioned biomass plants suggest an indicative investment cost of 400,000 – 600,000 EUR/MW of installed capacity, based on a plant size of 20 MW.[34]

Power from municipal solid waste is under development in India. India's waste-to-energy programme has been beset with problems due to India's waste management system, which does not always divide waste into organic municipal waste and industrial waste streams in landfills. Approximately 80 per cent of the municipal waste generated in India is organic, moist, and with low calorific value—factors which make incineration an inefficient method of disposal. There are also concerns about hazardous material included with the waste.[35]

Notable failures include the INR 410 million (EUR 6.7 million) Swedish incinerator in Timarpur in Delhi, which ran for only six days in 1991 as the waste delivered to it contained too much sand and ash, and the 5-MW Lucknow municipal waste-to-energy plant which was only able to operate at a capacity of 0.3-0.5 MW because only 40 tonnes per day of Lucknow's 1,250 daily production of municipal waste could be used as fuel.[36]

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[33] India Renewable Energy Development Agency, IREDA News April-December 2009. Available at <www.ireda.gov.in/pdf/April-December_2009.pdf>.
[34] India Renewable Energy Development Agency, IREDA News April-December 2009. Available at <www.ireda.gov.in/pdf/April-December_2009.pdf>.
[35] India Carbon Outlook 2009. Available at <india.carbon-outlook.com/content/primer-waste-energy>.
[36] Supreme Court Committee for Waste Management, Municipal Waste-to-Energy. Available at <www.docstoc.com/docs/49830253/Municipal-Waste-To-Energy-Mrs-Almitra-H-Patel-Member-Supreme>

4.3.5.2 Biogas

Biogas is frequently used for rural electrification projects. As of March 2009 there were 4.1 million small biogas plants, generally between 1-6 m^3, installed in India. These plants supplied an estimated 25 million m^3 of gas a day. Cow manure is the general feedstock.[37] In 2009/10 three such off-grid projects were completed in Tamil Nadu and 11 in Kerala. During the same time, one new project has been sanctioned to Haryana. Project proposals received from the state of Andhra Pradesh, Goa, Maharashtra, Tamil Nadu and by the Khadi Village Industries Commission are under consideration.[38]

Landfill gas projects are only starting to be developed in India. Only a few states (Maharashtra, Arunachal Pradesh, Tripura, Mizoram, West Bengal, Madhya Pradesh, Chhattisgarh, Gujarat, Punjab, Himachal Pradesh, Haryana, Rajasthan, Goa, Pondicherry, Andhra Pradesh and Karnataka) have started to establish modern engineered landfills and a proper waste recovery system. However, there is large potential.[39]

Biomass gasification projects have also been established to provide power to rural off-grid communities. As of 31 January 2010, there was a total installed capacity of 1.0 MW of small-scale village-level biomass gasifiers. The target for that year was 2.0 MW. For 2010-11 the government has a target of 4 MW of new off-grid biomass gasification plants to be added and for 6 MW of new grid-connected biomass gasification plants.[40]

4.3.6 Solar Energy

4.3.6.1 Solar PV

In November 2009 the government approved the ‘Jawaharlal Nehru National Solar Mission’ (JNNSM), a programme with the target of establishing India as a world leader in solar energy and to achieve grid parity for solar power by 2022. The programme has a target of 20,000 MW of solar power installed by 2022, compared to 10 MW in March 2010. There are interim targets of 1,000 MW by 2013 and 10,000 MW by 2017. Of the 1,000 MW by 2013 target, 100 MW is for small-scale roof-top systems and 200 MW will be for off-grid rural electrification.[41]

Solar PV installations on average cost approximately 200,000 INR/kW (1,649 EUR/kW) of installed capacity and have an average levelised generating cost of 197-329 EUR/MWh.[42]

4.3.6.2 Concentrated Solar-thermal Power

As of September 2010, no concentrated solar-thermal power projects were operational or under construction in India. In 2009, the government, however, gave permission for three

[37] MNRE, Biogas: The How and the Where, Renewable Energy, June 2009, Vol. 2, Issue 6. Available at <www.mnre.gov.in/akshayurja/june09-e.pdf>.
[38] Ministry of New and Renewable Energy, Chapter 6, Annual Report 2010. Available at <www.mnre.gov.in/annualreport/2009-10EN/Chapter 6/chapter 6_1.htm>.
[39] Methane to Market India. Landfill. Available at <www.methanetomarketsindia.com/sectors/landfils.htm>.
[40] Ministry of New and Renewable Energy, Chapter 6, Annual Report 2010. Available at <www.mnre.gov.in/annualreport/2009-10EN/Chapter 6/chapter 6_1.htm>.
[41] Ministry of New and Renewable Energy, Jawaharlal Nehru National Solar Mission, Annual Report 2010. Available at <www.mnre.gov.in/annualreport/2009-10EN/Chapter 3/chapter 3_1.htm>.
[42] Solar India Online. Available at <www.solarindiaonline.com/solar-india.html>.

projects (see Table 4.14). All three projects are in the early planning stages. The assumed levelised generating cost for CSP is 164-247 EUR/MWh.[43]

Table 4.14: Proposed concentrated solar-thermal projects in India

Developer	Capacity/technology	Location
Suryachakra Power Corporation	5 MW parabolic trough	Medak Distric, Andhra Pradesh
South Asian Agro Industries	5 MW parabolic trough	Balodabazar, Raipur District, Chhattisgarh
KG Design Services	1 MW tower	Santhanir, Sivaganaga

Source: Ministry of New and Renewable Energy, Chapter 6, Annual Report 2010. Available at <www.mnre.gov.in/annualreport/2009-10EN/Chapter 6/chapter 6_1.htm>.

4.3.7 Small Hydro

The theoretical total potential for small hydropower (≤25 MW) in India of capacity has been estimated at 15,000 MW distributed across 4,554 sites. The top five states in order of small-hydro potential are Himanchal Pradesh, Uttaranchal, Jammu and Kashmir, Karnataka, and Maharashtra. Over 674 small hydro projects totalling 2,559 MW of generating capacity were in operation on 31 March 2009, with a further 188 projects totalling 483 MW under construction. [44]

The government is encouraging the development of small hydro projects and aims to double the current growth to 500 MW of new capacity per year, with total installed capacity of 4,000 MW by the end of 2012. Past capacity addition plans have been relatively successful; for instance, under India's 10th Energy Plan, 600 MW of new small hydropower was targeted, of which 537 MW was completed.[45]

4.3.8 Geothermal

Geothermal power in India is in theory an attractive and high-potential source of energy which is barely exploited. According to the government there are 340 hot springs in India, but it is not known how many are suitable for power generation. The first geothermal power plant project in India was announced in August 2010. A consortium led by Tata Power, the largest independent power producer in India, plans to construct a 25-MW geothermal power plant in Andhra Pradesh's Khammam district by 2012.[46]

4.3.9 Marine (Wave/Tidal)

India has had a 150-kW prototype grid-connected wave generator, based on the oscillating water column principle, installed in Thiruruvananthpuram, Vizhinjam Fisheries Harbor since 1990. The project is used to power a desalination plant.[47]

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[43] Solar India Online. Available at <www.solarindiaonline.com/solar-india.html>.
[44] Energy Alternatives India, Hydropower. Available at <www.eai.in/ref/ae/hyd/hyd.html>.
[45] R.Venkateswaran (Rightlinx (India) Limited), Small Hydro Potential in India, Third Hydropower for Today Forum, June 2007. Available at <www.inshp.org/THE 3rd HYDRO POWER FOR TODAY Forum/Presentations/India/SMALL HYDRO POTENTIAL IN INDIA.pdf>.
[46] Shannon Roxborough, Tata Power Looks to Add Geothermal to India's Energy Mix, Energy Bloom, 31 August 2010. Available at <www.energyboom.com/geothermal/tata-power-looks-add-geothermal-indias-energy-mix>.
[47] Sharmila N. et al, *Wave Powered Desalination System*, National Institute of Ocean Technology.

The country's first tidal power generation project is under construction at Durgaduani Creek of the Sundarbans. The 3.75-MW plant is a technology demonstration project and will span over an area of 4.5 km. The USD 12.6 million project is 90 per cent funded by the federal government and 10 per cent by the state government and is expected to be completed in 2011.[48] In late 2009, a British company, Atlantis Resources, was awarded a contract to undertake a feasibility study of developing a 100 MW tidal power plant off the coast of Gujarat.[49]

4.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	**1/5**
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. *A high debt ratio may lead to negative change in the incentive policy for renewable energy*.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

4.4.1 Government Structure

India is a secular democratic republic with a parliamentary system of government which is federal in structure with certain unitary features. The constitutional head of state is the president, but real executive power is vested with the prime minister, who heads a council of ministers that are collectively answerable to the lower house of parliament, the House of the People.[50]

The two main political parties in India are the Indian National Congress (INC), the current governing party, and the Bharatiya Janata Party (BJP). These two political parties have dominated Indian politics since 1950. In the last elections held in 2009, the INC won with 35.4 per cent of the vote, and the BJP was a close second with 33.3 per cent of the vote.

Both the INC and the BJP have emphasised the risk of climate change in their campaign literature, as well as stressing the benefits for India in transitioning to a low-carbon economy. The next elections are due to be held in 2014, making short-term changes in current renewable energy policy unlikely.

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[48] Ministry of New and Renewable Energy, Energy from Tidal Waves, 2008. Available at <mnre.gov.in/press-releases/press-release-25042008.pdf>.
[49] Rhys Blakely, British company to help India harness the power of the sea, The Times, 28 November 2009. Available at <business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article6935567.ece>.
[50] Indian Government. Constitution of India. Available at <india.gov.in/govt/constitutions_india.php>.

4.4.2 Government Debt

India's gross external debt was estimated at USD 223.9 billion in 2009, which was equivalent to 58 per cent of GDP,[51] while the fiscal deficit for the 2009-2010 fiscal year was 6.9 per cent. India's fiscal position is expected to improve slightly to 5.7 per cent in 2010-2010, according to government projections, and maintain its course on an improving trajectory until 2014.[52]

4.4.3 Targets and Commitments

The 2008 National Action Plan on Climate Change delineates the framework for India's renewable energy strategy. Policy objectives include an increase in the consumption of renewable power to 5 per cent of total power consumption by 2010, followed by a 1 per cent increase for the subsequent year. Included within this initiative is the ambition of reaching 20 GW of installed capacity of solar power by 2022.[53] The government in late 2008 introduced a target to cut the carbon intensity of the economy by 25 per cent from 2009 levels.[54]

Table 4.15: Indian government commitments

GHG emissions	A 2020 government target to cut the carbon intensity of the economy by 25 per cent compared to 2009 levels.
Renewable energy (RE)	No target.
Renewable electricity	A government target of 5 per cent of consumption from RE sources by 2010, increasing by 1 per cent each subsequent year.

Source: Prime Minister of India, National Action Plan on Climate Change, 2008. Available at <pmindia.nic.in/climate_change.htm> and <www.mnre.gov.in/annualreport/2009-10EN/content.htm>.

4.4.4 Public Sentiment

The majority of Indians seem to back the promotion of renewable power, even if it imposes costs on them. A poll conducted in 2008 found that 63 per cent of Indian respondents favoured requiring utilities to use more renewable energy even if this increased the cost of energy.[55]

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[51] CIA. World Factbook: India. Available at <https://www.cia.gov>.
[52] Reuters, India 2010/2011 fiscal deficit seen at 5.7 pct, 25 February 2010. Available at <in.reuters.com/article/idINIndia-46464120100225>.
[53] Prime Minister of India, National Action Plan on Climate Change, 2008. Available at <pmindia.nic.in/climate_change.htm> and <www.mnre.gov.in/annualreport/2009-10EN/content.htm>.
[54] India to Reduce Carbon Emissions by 25% by 2020, Hindustan Times, December 2009. Available at <www.hindustantimes.com>.
[55] World Public Opinion, World Publics Strongly Favor Requiring More Wind and Solar Energy, More Efficiency, Even If It Increases Costs, 2008. Available at <www.worldpublicopinion.org/pipa/articles/btenvironmentra/570.php?lb=bte&pnt=570&nid=&id=>.

4.5 Grid Connection Risk Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Non-Discriminatory Access</td><td>One point if the transmission function is not legally separated from generation.
If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid.</td><td>0</td><td rowspan="4">1/5</td></tr>
<tr><td>Availability and Clarity</td><td>Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.</td><td>1</td></tr>
<tr><td>Costs</td><td>One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.</td><td>0</td></tr>
<tr><td>Investment</td><td>One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.</td><td>0</td></tr>
</table>

4.5.1 Functional Separation

The Indian power sector is predominantly state controlled but not vertically integrated. The 2003 Electricity Act restructured the Indian electricity industry by unbundling the vertically integrated electricity utilities in the Indian states and establishing State Regulatory Commissions (SERCs) in charge of setting electricity tariffs. The act also opened access to the Indian transmission system, allowing consumers to purchase their electricity from any producer.

State-owned ‘Public-Sector Undertakings’ (PSUs) are responsible for the generation of electricity, and state-owned transmission companies are responsible for its dispatch. Government-owned utilities jointly account for over 85 per cent of generating capacity, and over 99 per cent and 90 per cent of the transmission and distribution networks, respectively.[56]

The main PSUs are:

- National Thermal Power Corporation (NTPC)
- National Hydroelectric Power Corporation (NHPC)
- Nuclear Power Corporation of India (NPCI)

Several state-level corporations such as Maharashtra State Electricity Board are also involved in the generation of electricity.

Power Grid Corporation of India Limited (PGCIL) is the designated central transmission system operator (TSO), owning 80 per cent of India’s inter-state transmission network and 95 per cent of the transformation capacity at that level. There are 24 state grid operators that operate the transmission and distribution system in the state.

The government is committed to increasing functional separation in the power sector, and are currently looking at ways of creating separation between PGCIL’s role as the central transmission utility and the controller of the regional load despatch centres. The policymakers

[56] Global Transmission Information, India. Available at <www.globaltransmission.info/archive.php?id=395>.

and regulators believe that such a dual role could discourage private sector participation in transmission, which the government wants to promote. The Indian government has already approved the formation of an independent system operator that would operate as PGCIL's subsidiary for the first three years of operations and independently thereafter. The government has also announced more than a dozen new transmission projects that will be reserved for the private sector. [57]

4.5.2 Grid Capacity

PGCIL faces two main challenges in the short and medium term: it needs to upgrade the transmission system to be able to accommodate increases in generating capacity, and it needs to be more flexible in order to facilitate the movement and trading of power across state borders.

PGCIL aims to invest INR 550 billion between 2007 and 2012, adding approximately 67,000 km in line length and around 90,000 MVA in transformation capacity. In 2007/08, PGCIL invested over INR66 billion.

The development of the national grid has proceeded in phases. In 2007, the interregional transmission capacity was increased to about 14,000 MW, through a combination of high capacity AC (765 kV and 400 kV) and HVDC lines. In this phase, the North-East-West (NEW) grid was formed through the synchronisation of all regional grids, except the southern grid, in August 2006. The southern region is also technically connected to this grid, but asynchronously. As of September 2008, the interregional transfer capacity stood at about 17,000 MW.

In the third phase, which is to be completed by 2012, the interregional power transfer capacity will be further raised to 37,700 MW. At the end of this phase, there will be a ring of 765 kV transmission lines interconnecting the eastern, western and northern regions.[58]

4.5.3 Access and Connection Cost

Power plants under 50 MW are generally connected directly to the state power grid, while power plants over 50 MW are connected to the inter-state power grid. The grid reinforcement costs for generators connecting to the transmission grid are borne by the grid operator (shallow connection charges). Each state has its own grid regulation.[59]

[57] Global Transmission Information, India. Available at <www.globaltransmission.info/archive.php?id=395>.
[58] See Power Grid Corporation of India's website at <www.powergridindia.com/PGCIL_NEW/home.aspx>.
[59] For more information see the Central Electricity Regulatory Committee's website at <www.cercind.gov.in>.

4.6 Planning Permission Risk Index

Measure		Value	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**1/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

4.6.1 Complexity and Expected Timescales

The Central Electricity Regulatory Committee issues licences to generators. Licences are not required for off-grid electrification projects. Due to the federal system of government in India, each state also has their own rules and regulations concerning energy projects and there is not always consistency between the states.[60]

After a recent change in laws, foreign direct investment is allowed to cover 100 per cent of a power project, including generation, transmission and distribution. The government is encouraging investment in the power sector and is trying to improve regulations to make investment easier.[61]

4.6.2 Local Opposition and Procedural Improvements

Given the ongoing need for more power stations to meet demand, there is very little public opposition to any specific power plant development.[62] There have been, however, protests about possible problems with land deals some developers have made with tribal populations.[63]

[60] The Electricity Act 2003. Available at <aptel.gov.in/pdf/The%20Electricity%20Act_2003.pdf>.
[61] Investment Commission of India, Power. Available at <www.investmentcommission.in/power.htm>.
[62] Nuclear Power Corporation of India, Public and Political Acceptance of Nuclear Power. Available at <www.npcil.nic.in/pdf/Acceptance%20of%20NUPOWER.ppt>.
[63] Ben Arnoldy, As India looks at cutting carbon, a wind farm scandal, Christian Science Monitor, 31 August 2010. Available at <www.csmonitor.com/World/Global-News/2010/0831/As-India-looks-at-cutting-carbon-a-wind-farm-scandal>.

4.7 Conclusion

There is significant demand for new generating capacity in India due to economic growth and rising standards of living. There is already insufficient capacity to meet peak demand in almost every state in the country. To meet the projected peak demand in 2017 of 224 GW, almost 90 GW of new capacity will need to be completed. While nuclear power is expected to increase, with such a huge demand increase expected, plus security of supply concerns, the government is pursuing all feasible energy sources.

Despite the global economic recession, investment in the clean energy sector continues. In 2009, USD 2.7 billion was invested in clean energy in India, ranking it eighth in the world. Due to the effects of the global economic downturn this figure represents a decrease from USD 3.4 billion in 2008, however investment in 2010 is projected to increase.[64] Wind power attracted the most investment, but with the government's new Jawaharlal Nehru National Solar Mission, solar power investment can also be expected to increase.

While there are concerns regarding the ability of the grid, work on enhancing the system is ongoing and more investment in the system is expected.

[64] UNEP SEFI, Global Trends in Sustainable Energy Investment 2010. Available at <sefi.unep.org/>.

Chapter 5: Indonesia

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
An unattractive incentive regime with no fixed tariffs for renewable power.	**0/5**

2. Power Market Opportunities Index	Value
Indonesia is suffering a major electricity supply shortage, with capacity deficits in many areas.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind, Geothermal
Emerging Technologies Technologies that have growth potential in the country.	Solar PV, Marine energy

Risk Indices

4. Political Will Risk Index	Value
There is a political consensus that renewable power is needed, but low electricity prices are seen as a political entitlement by the public. Investment in renewable power will likely have to be funded from central budgets.	**1/5**

5. Grid Connection Risk Index	Value
Grid connection fees are high and grid capacity expansion is needed. This holds especially true in isolated rural areas away from the Jamali grid.	**3/5**

6. Planning Permission Risk Index	Value
Delays of years not uncommon. Permit requirements are numerous and there is no authority tasked with streamlining the process for renewable energy investors.	**3/5**

5.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets*.	0	**0/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	0	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity*.	0	

5.1.1 Operating Incentives

The state power monopoly PLN (*Perusahaan Listrik Negara*) is obligated to purchase all output from renewable power installations of up to 10 MW on a 10-year contract basis. The minimum offered price in 2010 stood at 656,000 IDR/MWh (52.48 EUR/MWh[1]) for electricity fed into the low-voltage grid, and 1,004,000 IDR/MWh (80.32 EUR/MWh) for electricity fed into the high-voltage grid. In addition to this floor price, a multiplier is applied which varies from region to region (see Table 5.1). The attractiveness of this incentive to foreign investors is, however, limited by the 'Negative Investment' clause of the 2007 investment law which prevents foreign ownership of a share greater than 49 per cent of any power project under 10 MW (90 per cent for geothermal projects).[2]

It is possible for independent power producers to negotiate higher rates than those referred to in Table 5.1, although negotiations are conducted on a case-by-case basis. In the case of geothermal power, the maximum price that PLN can pay is 97 USD /MWh (73.1 EUR/MWh).[3]

PLN is authorized to work in partnership with private sector developers and 33 geothermal projects, totalling 3,097 MW, and one hydropower project of around 30 MW are available for private sector participation in cooperation with PLN. The conditions will be negotiated on a case-by-case basis.[4]

[1] The conversion rate used is EUR 0.00008 = IDR 1(the average exchange rate over the first 6 months of 2010).
[2] Red Tape Blocks Clean Energy Investment in Indonesia, Jakarta Globe, May 2010. Available at <www.thejakartaglobe.com/business/red-tape-blocks-clean-energy-investment-in-indonesia-us/377251>.
[3] Dewan Perwakilan Rakyat Republik Indonesia, Indonesia's Encouraging Clean Energy Initiative, 2010. Available at <www.aipasecretariat.org/wp-content/uploads/2010/06/Ec-Indonesia-Clean-Energy.pdf>.
[4] Presidential regulation no. 4 2010. Available at <penconsulting.com/documents/Presidential_Regulation_No_4_Year_2010.pdf>.

Table 5.1: Minimum compensation rates for renewable power sold to PLN in 2010

Region	Connection	IDR/MWh			EUR/MWh
		Base rate[a]	Multiplier	Total	Total[b]
Sumatra	Low-voltage	656,000	1.2	787,200	62.976
	High-voltage	1,004,000	1.2	1,204,800	96.384
Java-Madura-Bali	Low-voltage	656,000	1	656,000	52.48
	High-voltage	1,004,000	1	1,004,000	80.32
Kalimantan	Low-voltage	6,56,000	1.3	852,800	68.224
	High-voltage	1,004,000	1.3	1,305,200	104.416
Sulawesi	Low-voltage	656,000	1.3	852,800	68.224
	High-voltage	1,004,000	1.3	1,305,200	104.416
Nusa Tenggara	Low-voltage	656,000	1.3	852,800	68.224
	High-voltage	1,004,000	1.3	1,305,200	104.416
Maluku	Low-voltage	656,000	1.3	852,800	68.224
	High-voltage	1,004,000	1.3	1,305,200	104.416
Papua	Low-voltage	656,000	1.5	984,000	78.72
	High-voltage	1,004,000	1.5	1,506,000	120.48

Notes: [a] Payable for the generation proceeding from the first 10 MW of installed capacity.
[b] The conversion rate used is the average EUR-IDR exchange rate over the first 6 months of 2010 of 0.00008 EUR to 1 IDR.
Source: The conversion rate used is EUR 0.00008 = IDR 1 (the average exchange rate over the first 6 months of 2010).

5.1.2 Investment Support

The following investment incentives for private developers of renewable power in Indonesia are available:

- A six-year tax holiday in which income tax is applicable to only 95 per cent of a project's revenue
- Exemption of project-essential materials from import duty
- Exemption of project-essential materials from VAT.[5]

As a signatory to the Kyoto Convention, renewable energy projects in Indonesia may be entitled to receive CDM credits.

Indonesia also stands to benefit from various multinational funding initiatives. For example, the World Bank's Clean Technology Fund (CTF) and the ADB have established a fund for lending to renewable energy projects in Indonesia, including those developed by Pertamina (state-owned oil company), PLN, as well as the private sector. It has been reported that Indonesia has been awarded USD 400 million of funding from the CTF to finance geothermal and biomass projects.[6]

[5] Dewan Perwakilan Rakyat Republik Indonesia, Indonesia's Encouraging Clean Energy Initiative, 2010. Available at <www.aipasecretariat.org/wp-content/uploads/2010/06/Ec-Indonesia-Clean-Energy.pdf>.
[6] ADB, Clean Investment Plan for Indonesia, January 2010. Available at <www.adb.org/Documents/Reports/Others/INO-CTF-Investment-Plan.pdf>.

5.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	1	**4/5**
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	1	

5.2.1 Energy Consumption

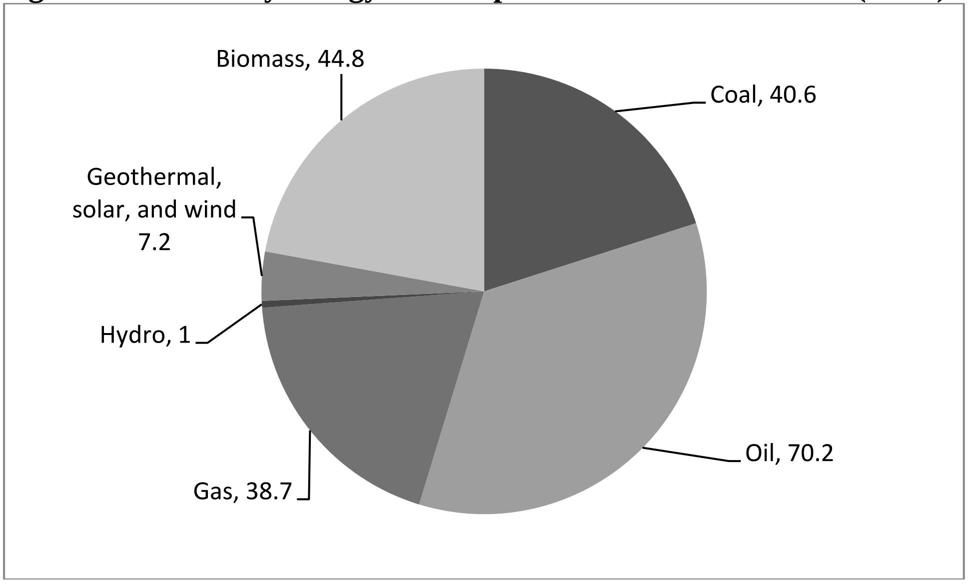
Although Indonesia is currently an energy exporter with a high degree of self-sufficiency, the country's energy reserves are not very abundant given its large and growing population. While its gas reserves are static, Indonesia's oil reserves are decreasing. In 2004 Indonesia became a net importer of oil and in January 2009 suspended its membership in OPEC.

In 2008, primary energy consumption in Indonesia was 202.5 million tonnes of oil equivalent (Mtoe). Crude oil and coal provided the bulk of primary energy supply (see Figure 5.1). Biomass provided 22 per cent of supply, primarily for rural cooking and heating in communities that are not connected to the grid.[7] Between 1980 and 2008, primary energy consumption grew at an average annual rate of 4.6 per cent (except during the Asian financial crisis) while GDP grew at an average of 4.8 per cent during the same period. In the IEA's reference scenario, primary energy consumption is projected to grow to 330 Mtoe by 2030, a compound annual growth rate (CAGR) of 2.3 per cent from 2008 levels.[8]

Final energy consumption reached 145.1 Mtoe in 2008, an increase of 11.4 per cent on the previous year's figure. Over the period 2003-2008, final energy consumption grew at an annualised rate of 2.2 per cent.[9]

[7] Ministry of Energy and Mineral Resources, Handbook of Energy and Economic Statistics of Indonesia, 2009. Available at <www.esdm.go.id/publikasi/handbook/doc_download/987-handbook-of-energy-a-economic-statistics-of-indonesia-2009.html>.
[8] International Energy Agency, World Energy Outlook 2009.
[9] Ministry of Energy and Mineral Resources, Handbook of Energy and Economic Statistics of Indonesia, 2009. Available at <www.esdm.go.id/publikasi/handbook/doc_download/987-handbook-of-energy-a-economic-statistics-of-indonesia-2009.html>.

Figure 5.1: Primary energy consumption in Indonesia in 2008 (Mtoe): Total 202.5 Mtoe



Source: APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.

5.2.2 Electricity Sector

Peak demand in 2008 was 21,120 MW, a slight decrease from 21,306 MW in 2007 due to reduced economic activity. Between 2000, when peak demand was 15,320 MW, and 2008, peak demand had a CAGR of 4.1 per cent. The Ministry of Energy and Mineral Resources projects that electricity demand will continue to grow by an average of 9.2 per cent per year over the period 2008-2027.

Total installed generating capacity in 2008 amounted to 30,298 MW (see Figure 5.2), 3.6 per cent down from the previous year. This fall was mainly driven by a reduction in geothermal and conventional steam capacity of 10 per cent and 6 per cent, respectively. Approximately 85 per cent of total installed capacity was accounted for by installations owned by the government-owned power utility, PLN, with independent power producers (IPP) owning the remaining 15 per cent.

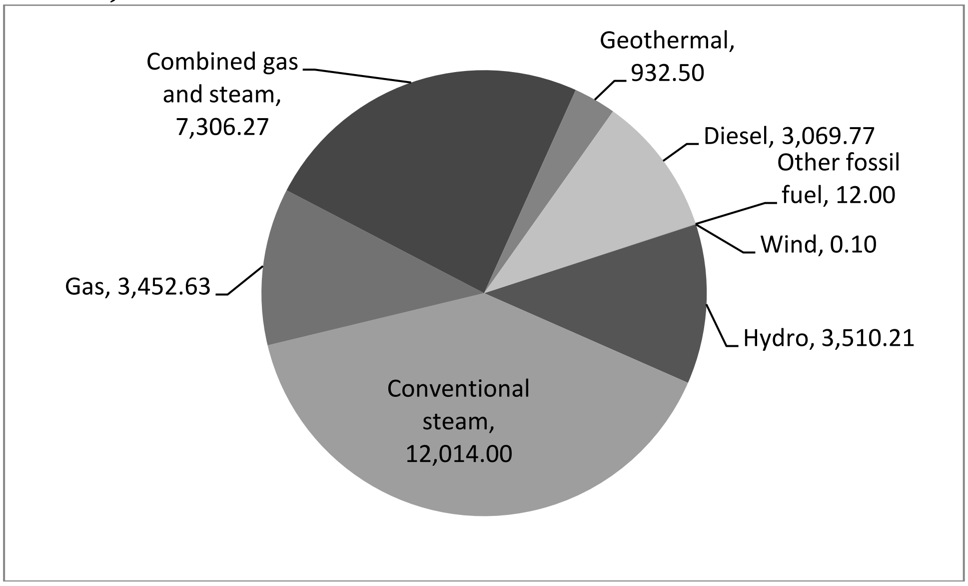
There are substantial capacity deficits in some parts of the country leading to power shortages at peak hours. It is projected that the capacity deficit will improve in most areas of the country by 2014, with the exception of the Java-Madura-Bali grid area due to the necessary retirement of some plants (see Table 5.2).

In December 2009, the government revised the 10,000-MW Fast Track Power Development Programme. Between 2009 and 2013, 10 GW of new generating capacity will be built, two-thirds of which will be in Java (see Table 5.3). PLN is also implementing phase two of the programme, which will see the addition of 10,677 MW of new generating capacity. In phase two, geothermal plants will comprise 4,583 MW and hydropower plants 1,174 MW with PLN expected to invest USD 7.605 billion to build 6.4 GW of new power plants while IPPs are expected to invest USD 8.45 billion for 4.26 GW.[10]

[10] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

Under the IEA's reference scenario (baseline 'business-as-usual' scenario), total installed generating capacity is projected to increase to 101 GW by 2030, which would represent a CAGR of 5.6 per cent from 2008 levels.[11]

Figure 5.2: Total installed generating capacity in Indonesia in 2008 (MW): Total 30,298 MW



Source: Ministry of Energy and Mineral Resources, Handbook of Energy and Economic Statistics of Indonesia, 2009. Available at <www.esdm.go.id/publikasi/handbook/doc_download/987-handbook-of-energy-a-economic-statistics-of-indonesia-2009.html>.

Table 5.2: Projected peak demand and available capacity in Indonesia in 2010 and 2014

Region	2010			2014		
	Peak demand	Available capacity	Reserve capacity	Peak demand	Available capacity	Reserve capacity
Sumatra	3,832	3,372	-460	5,202	8,507	3,305
Java-Madura-Bali	23,084	23,568	484	33,188	21,569	-11,619
Kalimantan Barat	291	163	-128	395	709	315
Kalimantan Tengah	433	317	-116	584	941	357
Kalimantan Timur	446	282	-164	603	954	352
Kepulauan Bangka Belitung	74	111	37	92	243	151
Sulawesi Utara	326	285	-41	433	1,138	705
Sulawesi Barat	782	787	5	1,022	1,548	526
Nusa Tenggara Barat	156	170	14	213	445	233
Nusa Tenggara Timur	98	68	-30	130	223	92
Maluku	108	107	42	145	251	106
Papua	165	98	-67	218	326	108
Total	29,795	29,328	-424	42,225	36,854	-5,369

Source: Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.

[11] IEA, World Energy Review 2009.

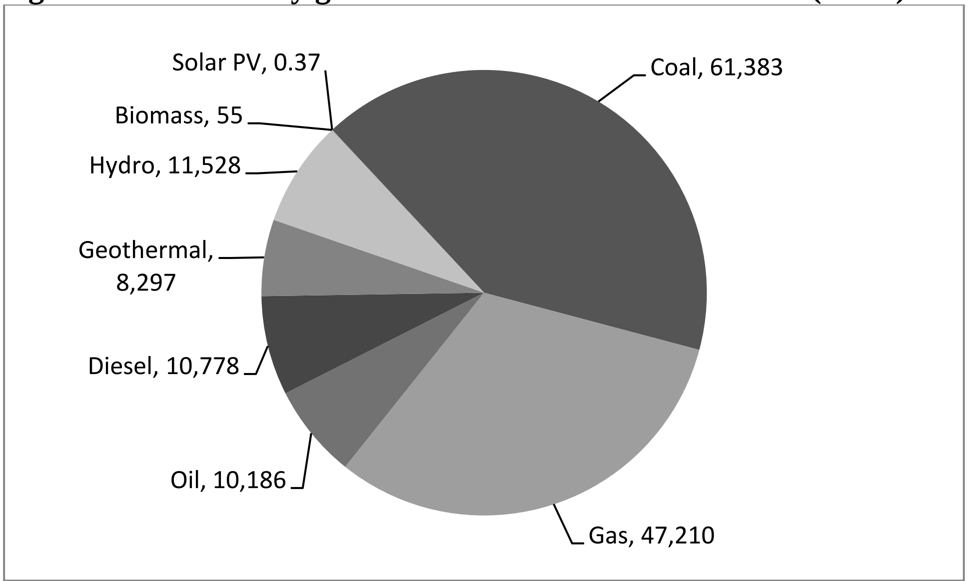
Table 5.3: New generating capacity planned in Indonesia between 2009 and 2013

Year	Capacity added in Java	Elsewhere
2009	915	0
2010	3,240	121
2011	1,975	1,558
2012	700	768
2013	660	0
Total	6,575	2,447

Source: Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

A total of 149,437 GWh of electricity was generated in 2008, a 4.9 per cent increase from 2007, mainly driven by an increase in output from geothermal, CCGT, and diesel generators. The growth in generation from each of these categories was 18.1 per cent, 13.8 per cent, and 19.2 per cent, respectively. Although coal was still an important component in the generation mix with 42 per cent of the total, 3.8 per cent less electricity was generated from coal in 2008 than in 2007. The share of total generation accounted for by IPP and captive power plants decreased slightly from 22.7 to 21.9 per cent in 2007-2008.

Figure 5.3: Electricity generation mix in Indonesia in 2008 (GWh): Total 149,437 GWh



Source: Ministry of Energy and Mineral Resources, Handbook of Energy and Economic Statistics of Indonesia, 2009. Available at <www.esdm.go.id/publikasi/handbook/doc_download/987-handbook-of-energy-a-economic-statistics-of-indonesia-2009.html>.

One of the reasons for the expected increase in power demand is the government’s drive to raise the rates of electrification from 65 per cent in 2009 to 95 per cent by 2015.[12] In the 2010 budget, the government allocated IDR 561.5 billion to electrifying 81,000 households in very remote areas (based on new and renewable energy), and IDR 591.5 billion to further extend PLN’s grid.[13]

[12] Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.

[13] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

5.2.3 Nuclear Power

As of September 2010 there were no operational nuclear power plants or any under construction; however, there are plans underway for nuclear power development. In 2009, the government asked the International Atomic Energy Agency (IAEA) to evaluate two sites for possible nuclear power development. The IAEA reported that Indonesia was suitable for nuclear power development. In 2010, a parliamentary commission advocated for the building of nuclear power plants.[14] However, Indonesian President Susilo Bambang Yudhoyono has said that his administration has no plans to develop nuclear power in the country.[15]

5.3 Technology Opportunities Index

Measure		**Technology**
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Onshore wind, Geothermal
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV, Marine energy

5.3.1 Renewable Electricity Generation

In 2008, total generation from renewable sources reached 19,880 GWh following five years of steady growth (see Table 5.4). At the end of 2009, Indonesia had over 5,816 MW of grid-connected renewable power, primarily hydropower, with an additional 86 MW under construction. Geothermal and hydropower are the most well established technologies (see Table 5.5). In contrast, wind and solar projects have mostly been adopted as solutions to off-grid electrification.

Table 5.4: Total generation of grid-connected renewable power in Indonesia from 2003 to 2008 (GWh)

Year	Hydro	Geothermal	Solar	Wind	Biomass	Total
2003	9,099	6,294	0	0	15	15,408
2004	9,674	6,656	0	0	20	16,350
2005	10,725	6,604	0	0	22	17,351
2006	9,623	6,658	0	0	32	16,313
2007	11,286	7,021	0	0.02	36	18,343.02
2008	11,528	8,297	0.37	0	55	19,880.37

Source: Ministry of Energy and Mineral Resources, Handbook of Energy and Economic Statistics of Indonesia, 2009. Available at <www.esdm.go.id/publikasi/handbook/doc_download/987-handbook-of-energy-a-economic-statistics-of-indonesia-2009.html>.

[14] Ariyanto Sudi, Center for Nuclear Energy Development, BATAN, IAEA TC workshop long range planning, Vienna, June 14-17, 2010. Available at <www.iaea.org/NuclearPower/Downloads/INPRO/Files/2010-June-IR-WS/Presentation_of_Indonesia_June_2010.pdf>.

[15] Lynn Lee, No Plans for Nuclear Power in Indonesia, The Strait Times, 19 June 2010. Available at <www.asianewsnet.net/home/news.php?id=12605&sec=1>.

Table 5.5: Total installed generating capacity of grid-connected renewable power in Indonesia from 2003-2009 (MW)

Year	Hydro	Geothermal	Wind	Biomass	Solar	Total
2003	3,170	785	0	0	0	3,955
2004	3,199	800	0	0	0	3,999
2005	3,220	800	0	0	0	4,020
2006	3,532	800	0	0	0	4,332
2007	3,529	1,042	0.5	160	10	4,742
2008	4,286	1,052	1.4	300	14.1	5,654
2009[a]	4,287	1,189	1.4	320	18.3	5,816

Source: Ministry of Energy and Mineral Resources, Handbook of Energy and Economic Statistics of Indonesia, 2009. Available at <www.esdm.go.id/publikasi/handbook/doc_download/987-handbook-of-energy-a-economic-statistics-of-indonesia-2009.html>; MEMR, Capacity in 2009 and the 2010-2014 Energy Strategy. Available at <www.esdm.go.id/download/Kinerja%20Sektor%20ESDM%20Tahun%202009.pdf>.

5.3.2 Resource Potential

Although Indonesia has significant renewable energy potential, it remains largely under-utilised. According to the Ministry of Energy and Mineral Resources, the country's renewable power potential includes 450 MW of small hydropower and 50 GW of biomass. Solar irradiation levels in Indonesia are also high, with an average of 4.80 kWh/m^2 per day throughout the country. On average wind speeds are relatively low and vary between 3-6 m/s throughout the country.

Indonesia has approximately 40 per cent of the world's reserves of geothermal energy.[16] According to the Ministry of Energy, as of March 2010, Indonesia's geothermal potential was estimated at 28,100 MW, up from 27,000 MW in 2004. This potential is equivalent to 12 billion barrels of oil, which is nearly twice as large as the country's 6.4 billion barrels of oil reserves.[17] Almost a third (about 8,000 MW) of the potential is located in Java and Bali, the most densely inhabited islands with the highest demand for electricity.[18]

Table 5.6: Renewable energy potential in Indonesia

Source	Installed capacity (MW)	Potential (MW)	Undeveloped potential (%)
Hydropower	4,264	75,670	94
Geothermal	1,062	27,510	96
Mini-hydropower	86.1	500	83
Biomass	445	49,810	99
Wind	1.1	9,190	99
Ocean	0	35	100

Source: US Department of Commerce, Renewable Energy Market Assessment: Indonesia, May 2010. Available at <ita.doc.gov/td/energy/Indonesia%20Renewable%20Energy%20Assessment%20(FINAL).pdf>.

5.3.3 Levelised Generation Costs

As there are no direct operating incentives for renewable power in Indonesia it is not possible to compare incentives with levelised generating costs. It is worth noting, however, that

[16] Indonesia's geothermal development, Jakarta Post, 2009. Available at <www.thejakartapost.com/news/2009/11/30/indonesia%E2%80%99s-geothermal-development.html>.
[17] Indonesia's Geothermal Potential Even Bigger Than Previously Estimated, March 2010. Available at <www.energyboom.com/geothermal/indonesias-geothermal-potential-even-bigger-previously-estimated>.
[18] Overview of Policy Instruments for the Promotion of Renewable Energy and Energy Efficiency in Indonesia March 2010. Available at <www.serd.ait.ac.th/cogen/62/reports/countries/indonesia.pdf>.

operating incentives are an imperfect indicator of how much revenue IPP owners actually receive. For instance, although the Paiton I coal-fired plant is paid 49.3 USD/MWh, a clause in the power purchasing agreement negotiated between the companies means that PLN will pay an additional USD 4 million per month for a period of 30 years, bringing the total compensation to approximately 66.2 EUR/MWh.[19]

5.3.4 Wind Power

5.3.4.1 Onshore Wind Power

Indonesia has a low installed wind capacity, estimated at only 1.4 MW in 2009. The potential usefulness of wind as a generation source is limited due to modest wind speeds along the equator; however, there may be potential for up to 450 MW of wind-powered capacity, mostly in the eastern islands where wind speeds can be higher. The capacity of the grid in these islands is not capable of sustaining large projects, thus it is likely that most wind power developments in these areas will be small-scale projects.[20]

Wind power plays a minor role in the national energy strategy for 2010-2014, with target additional capacity of 18 MW to be added over this period, at projected total cost of USD 123.9 million (EUR 93.4 million). There is also a supplemental target of a total installed capacity of 250 MW of wind power by 2025.[21]

5.3.4.2 Offshore Wind Power

There were no offshore wind farms in operation or planned in Indonesia as of September 2010. However, development is possible given the higher wind speeds that can be found offshore of the islands.[22]

5.3.5 Biomass

5.3.5.1 Solid Biomass

Indonesia has substantial biomass potential, with a variety of potential feedstocks from coconut, rice and sugar plantations, forestry biomass, as well as municipal solid waste (see Table 5.7). The total potential has been estimated at 49.81 GW. In 2008 the installed capacity for biomass-fired electricity generation was approximately 500 MW, much of which was off-grid.

The most promising commercial application for biomass-fuelled power plants is when they are integrated with agricultural processing plants. In June 2007, the first biomass power plant integrated with a processing plant was commissioned, a 12-MW plant fuelled with palm oil

[19] Perdana A., On prospects of sustainable energy sources for power generation in Indonesia, Department of Energy and Environment, Sweden, 2008. Available at <www.scribd.com/doc/19478708/On-Prospects-of-Sustainable-Energy-Sources-for-Power-Generation-in-Indonesia>.
[20] US Department of Commerce, Renewable Energy Market Assessment: Indonesia, May 2010. Available at <ita.doc.gov/td/energy/Indonesia%20Renewable%20Energy%20Assessment%20(FINAL).pdf>.
[21] Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.
[22] US Department of Commerce, Renewable Energy Market Assessment: Indonesia, May 2010. Available at <ita.doc.gov/td/energy/Indonesia%20Renewable%20Energy%20Assessment%20(FINAL).pdf>.

waste. There is an estimated potential of 1.16 GW suitable for integrated power generation from biomass by-products.[23] Table 5.8 sets out the distribution of this potential in Indonesia.

Table 5.7: Distribution and energy potential of biomass in Indonesia

Feedstock	Location	Production (million tons/year)	Technical potential (million GJ/year)
Rubber wood	Sumatra, Kalimantan, Java	41	120
Logging residues	Sumatra, Kalimantan,	4.5	19
Sawn timber residues	Sumatra, Kalimantan,	1.3	13
Plywood and veneer production residues	Kalimantan, Sumatra, Java, Irian Jaya, Maluku	1.5	16
Sugar residues	Java, Sumatra, South Kalimantan	23.6	78
Rice Residues	Java Sumatra, Sulawesi	55	150
Coconut residues	Sumatra, Java, Sulawesi	1.1	7
Palm oil residues	Sumatra, Kalimantan, Sulawesi, Maluku, Nusa Tenggara, Irian Jaya	8.2	67

Source: METI, Biomass Forum, 2006. Available at <www.meti.or.id/prosiding.php>.

Table 5.8: Biomass generating potential integrated with agricultural processing plants in Indonesia

Feedstock	Sumatra	Kalimantan	Sulawesi	Java	Total
Palm oil mills	171.1	13.8	28.8	0	213.7
Rice mills	41.3	11.5	18.6	103.6	175
Wood mills	64.9	128.8	3	25.2	221.9
Sawmills	76.7	75.9	0	0	152.6
Sugar mills	236	0	9.6	151.2	396.8
Total	590	230	60	280	1160

Source: METI, Biomass Forum, 2006. Available at <www.meti.or.id/prosiding.php>.

In the 2010-2014 Energy Masterplan, the government announced three biomass plants ready for construction. They are:

- A EUR 12.4 million, 10.3-MW palm oil residue plant in Pangkalanbrandan, Sumatra.
- A 10.5-MW palm oil residue plant in Riau, Sumatra
- A 3-MW rice husk plant in Lampung, Sumatra.[24]

5.3.5.2 Biogas

Biogas is not widely used in Indonesia as of 2010. However, in 2009, SNV, a Dutch development agency, conducted a feasibility study on promoting the use of biogas for off-grid communities. The results of the study indicated that there were few barriers and large potential. With partial funding from the Dutch government, a programme was launched in May 2009 to distribute 8,000 domestic biogas units. As of December 2009, 50 units were in place.[25] The UNDP and the World Bank are also promoting the development of biogas using agricultural waste in the areas that are redeveloping following the 2004 tsunami.[26]

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[23] MEMR, New Renewable Energy Potential. Available at <www.esdm.go.id/berita/umum/37-umum/1962-potensi-energi-baru-terbarukan-ebt-indonesia.html>.
[24] Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.
[25] Information from SNV World website at <www.snvworld.org>.
[26] World Bank. Available at <blogs.worldbank.org/eastasiapacific/node/2544>.

5.3.6 Solar Energy

5.3.6.1 Solar PV

Solar potential in Indonesia is relatively high, with an intensity of between 4.80 and 5.10 kWh/m^2 per day. The exploitation of this resource has however been slow due to the high investment costs involved and the lack of incentives designed to mitigate this factor. In particular, there is no mechanism by which consumers can sell their excess electricity to PLN. Installed solar capacity in 2010 is estimated at 12 MW, most of which has been installed in the form of roof-mounted solar PV panels in urban areas.[27] PLN has identified sites for five utility-scale solar power plants to be built on islands outside Java in 2010. The projects will be located in Bunaken (North Sulawesi), Wakatobi in Kendari (Southeast Sulawesi), Derawan (East Kalimantan), Banda Island (Maluku) and West Papua. A total of IDR 250 billion (EUR 20 million) was budgeted for the project.[28]

Solar energy is to play a major role in MEMR’s rural electrification drive, and the government has a target to install 1,297,008 50-W systems and 248 15-kW systems by 2014. The total cost of this is likely to be IDR 9.8 trillion (EUR 790 million). IDR 800 billion (EUR 63 million) has already been assigned for the purposes of providing solar PV units in the localities in 2010.[29]

5.3.6.2 Concentrated Solar-thermal Power

As of September 2010 there were no concentrated solar-thermal power projects operational or under construction in Indonesia.

5.3.7 Small Hydro

There is an estimated potential for 450 MW of small hydro in Indonesia, and as of 2009 there were 13 projects totalling 4,923 kW, with a further 80 kW under construction. The UNDP and the World Bank’s Global Environment Facility have started the Integrated Micro-hydro Development and Application Programme (IMIDAP), which aims to reduce barriers to small hydro development in Indonesia by building local capacity. The majority of the projects are for off-grid electrification.[30] Planned small hydro projects up to 2014 are listed in Table 5.9.

Table 5. 9: Planned small hydro projects in Indonesia from 2010 to 2014

Description	Sumatra	Jamali	Kalimantan	Sulawesi	Nusa Tenggara	Maluku	Papua	Total
Planned new capacity 2010-2014 (kW)	10,217	2,160	5,220	7,831	4,100	1,100	3,930	34,558
Investment cost (millions of EUR)	42.2	7.8	18.5	30.9	14.7	4.8	17.8	136.7

Source: Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id>.

[27] US Department of Commerce, Renewable Energy Market Assessment: Indonesia, May 2010. Available at <ita.doc.gov/td/energy/Indonesia%20Renewable%20Energy%20Assessment%20(FINAL).pdf>.
[28] Slamet Susanto, PLN to develop solar power stations, the Jakarta Post, 16 July 2010. Available at <www.thejakartapost.com/news/2010/07/16/pln-develop-solar-power-stations.html>.
[29] Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.
[30] For more information see the IMIDAP’s website at <imidap.mikrohidro.net>.

5.3.8 Geothermal

Indonesia has the world largest reserves of geothermal energy, approximately 40 per cent.[31] According to the Ministry of Energy, as of March 2010, Indonesia's geothermal potential was estimated at 28,100 MW, up from 27,000 MW in 2004.[32] Almost a third (about 8,000 MW) of the potential is located in Java and Bali, the most densely inhabited islands with the highest demand for electricity.[33] As of May 2010 the total installed capacity of those plants was 1,189 MW, which represents 4 per cent of total identified potential, including 420 MW operated by PLN and 749 MW by PT Pertamina (the national oil company) and its partners under joint operation contracts (JOCs). The government has a target of 9,500 MW of geothermal power to be installed by 2025. Table 5.10 lists geothermal power plants in Indonesia as of May 2010.

Table 5.10: Geothermal power plants in Indonesia in 2010

Plant name	First Year of commercial production	Capacity (MW)			Production (GWh/year)	Field operator
		PLN	JOC	Total		
PLTP Sibayak	2000	0	10 (2 units)	10	40	PT Dizamatara Powerindo
PLTP Salak	1994	180 (3 units)	195 (3 units)	375	2,948	Chevron Geothermal Indonesia Ltd.
PLTP Kamojang	1982	140 (3 units)	60 (1 unit)	200	1,100	PT. Indonesia Power
PLTP Darajat	1994	55 (1 unit)	204 (2 units)	259	1,987	Chevron Geothermal Indonesia Ltd.
PLTP Wayang Windu	2000	0	220 (2 units)	220	932	Magma Nusantara Ltd; PT. Star Energy
PLTP Dieng	1998	0	60 (1 unit)	60	300	PT. Geodipa
PLTP Lahendong	2001	60 (2 units)	0	60	146	PT Pertamina Geothermal Energy

Notes: PLTP: Pembangkit Listrik Tenaga Panas Bumi (Geothermal Power Plant)
JOC: Joint Operation Contract
Source: Prepared by LRI based on the data in Ministry of Energy and Mineral Resources website <portal.djmbp.esdm.go.id/dbb2>.

Among the existing seven plants, two are based on dry steam technology, and the remainder use flash steam technology. Suppliers of equipment include Mitsubishi Heavy Industries (Japan), Mitsubishi Electric (Japan), Fuji Electric (Japan), Ansaldo Energia (Italy), General Electric (USA) and Ormat (Germany).[34]

The electricity sale price is agreed between PLN and the developer of the geothermal power plant. The benchmark electricity selling price for any geothermal power purchasing agreement is regulated at a maximum of 97 USD/MWh by MEMR Regulation No. 05/2009

[31] Indonesia’s geothermal development, Jakarta Post, 2009. Available at <www.thejakartapost.com/news/2009/11/30/indonesia%E2%80%99s-geothermal-development.html>.
[32] Indonesia's Geothermal Potential Even Bigger Than Previously Estimated, March 2010. Available at <www.energyboom.com/geothermal/indonesias-geothermal-potential-even-bigger-previously-estimated>.
[33] Overview of Policy Instruments for the Promotion of Renewable Energy and Energy Efficiency in Indonesia March 2010. Available at <www.serd.ait.ac.th/cogen/62/reports/countries/indonesia.pdf>.
[34] Frost, Indonesia - Time to tap the ring of fire, 26 March 2010. Available at <www.frost.com/prod/servlet/market-insight-top.pag?Src=RSS&docid=173797191>.

on the Guidelines for Electricity Purchasing Price by PT. PLN;[35] however, the government has recently signalled its willingness to subsidise geothermal power purchasing agreements by agreeing to make up the difference between this ceiling price and the price demanded by the installation operator, in certain cases.[36] Table 5.11 shows the initial or benchmark price agreed between the developer and PLN,[37] and the technology used at different plants.

Table 5.11: Electricity and steam purchase prices for geothermal plants in Indonesia

Plant Names	Electricity purchase price (USD/MWh)	Steam purchase price (USD/MWh)	Technology
PLTP Sibayak	71	53.5	Flash steam plant
PLTP Salak	74	53.5	Flash steam plant
PLTP Kamojang	70.3	65.7	Dry steam plant
PLTP Darajat	69.5	42.5	Dry steam plant
PLTP Wayang Windu	72.4	54.6	Flash steam plant
PLTP Dieng	44.5	48.6	Flash steam plant
PLTP Lahendong	N/A	18.2	Flash steam plant

Source: Prepared by LRI based on the data on the Ministry of Energy and Mineral Resources website <portal.djmbp.esdm.go.id/dbb2>; Indonesia's Geothermal Development, 2002. Available at <jakarta.usembassy.gov/download/geo2002.pdf>.

The government is according a key role to geothermal development in its second 10,000-MW Fast Track Programme to encourage the adoption of renewable energy. The Ministry of Energy and Mineral Resources (MEMR) has identified 26 new geothermal project sites ready for development. Of that number seven have been tendered, six are in the bidding process and a further 13 are ready to bid. Up to 50 further sites are expected to be offered at a later date. In total, there are 44 geothermal projects included in the second phase of the Fast Track Programme, of which approximately 30 are intended to be awarded to IPPs. Initially, the government claimed that 4,733 MW would come from geothermal sources, but it has now said that the figure has been reduced to 3,977 MW. Of the total 3,977 MW planned, PLN plans to build 880 MW and it expects the rest to be built by IPPs. The government expects PLN's projects to be completed by 2014.[38]

A number of developers are looking into projects in Indonesia. Chevron, the world's largest geothermal energy producer in the world, is looking to increase the number of plants it currently has in the country. The company has had interests in two geothermal power plants since the mid-1980s. The Swedish company Tricorona is also looking into investing in a 50-MW geothermal plant.[39] In September 2010, Tata Power, India's largest IPP, in partnership with Australian company Origin Energy Limited and PT Supraco Indonesia, secured the contract for the 240-MW Sorik Marapi geothermal project in Northern Sumatra, Indonesia.

[35] Think Geoenergy, Indonesia to set geothermal electricity price at 9.7 US cents/ kWh, December 2009. Available at <thinkgeoenergy.com/archives/3136>.
[36] Geothermal Price Cap to be Lifted, Jakarta Globe, 29 March 2010. Available at <www.thejakartaglobe.com/business/geothermal-price-cap-to-be-lifted/372085>.
[37] Indonesia's Geothermal Development, 2002. Available at <jakarta.usembassy.gov/download/geo2002.pdf>.
[38] Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.
[39] Hilary Brenhouse, Indonesia Seeks to Tap Its Huge Geothermal Reserves, New York Times, July 2010. Available at <www.nytimes.com/2010/07/27/business/global/27iht-renindo.html?pagewanted=1>.

The project is expected to be operation in 2015.[40] Table 5.12 lists the projects under development and exploration.

Table 5.12: Geothermal power projects under development in Indonesia

Developer	Location
Sumitomo (from Japan)	South Sumatra
PGE (Pertamina Geothermal Energy)	South Sumatra (Lumut Balai) South Sumatra (Ulubelu) South Sumatra (Hululais) South Sumatra (Lpenuh River) North Sulawesi (Lahendong) North Sulawesi (Kotamobagu) West Java (Kamojang Unit 5) West Java (Karahas Bodas)
Chevron Geothermal	West Java (Darajat Mountain, Garut)
Medco Energi, Ormat Technologies and Itochu Corp.	North Sumatra
Star Energy	West Java (Bandung, Wayang Windu)
Ormat, Medco Energy, Kyushu Electric Power and Itochu	North Sumatra (Sarulla)
Terra Energy	Java
Tata Power, Origin Energy Limited and PT Supraco Indonesia	North Sumatra (Sorik Marapi)

Source: Geothermal Energy Association, Geothermal Energy: International Market Update, May 2010. Available at < www.geo-energy.org/pdf/reports/GEA_International_Market_Report_Final_May_2010.pdf>.

A number of international organisations and governments are offering investment incentives and assistance to geothermal development in Indonesia, including:

- In April 2010, the US Trade and Development Agency announced USD 1.6 million in grants for feasibility studies. USD 732,722 will go to PT Star Energy for the 370-MW Jailolo plant in Halmahera, USD 934,308 will go to PT Indonesia Power for the 300-MW Tangkuban Perahu project in West Java and Raser Technologies will be the sole source contractor.
- In April 2010, Indonesia signed a EUR 7 million loan from Germany for geothermal projects.
- The World Bank has announced USD 400 million for geothermal development in Indonesia through the Clean Technology Fund.[41]

5.3.9 Marine (Wave/Tidal)

With thousands of miles of coastline, the potential for ocean energy is significant at an estimated 10 MW to 35 MW per km of coastline. Currently, only one demonstration project has been developed—an ocean current system in the Lombok Strait.[42]

[40] Tata Power consortium bags 240MW Indonesian geothermal project, Economic Times (India), 2 September 2010. Available at < economictimes.indiatimes.com/news/news-by-industry/energy/power/Tata-Power-consortium-bags-240MW-Indonesian-geothermal-project/articleshow/6479540.cms>.

[41] Geothermal Energy Association, Geothermal Energy: International Market Update, May 2010. Available at <www.geo-energy.org/pdf/reports/GEA_International_Market_Report_Final_May_2010.pdf>.

[42] US Department of Commerce, Renewable Energy Market Assessment: Indonesia, May 2010. Available at <ita.doc.gov/td/energy/Indonesia%20Renewable%20Energy%20Assessment%20(FINAL).pdf>.

5.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	**1/5**
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. A high debt ratio may lead to negative change in the incentive policy for renewable energy.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

5.4.1 Government Structure

Indonesia's political system is a constitutional democracy, with a president who occupies the position of head of state and head of government, and a legislature made up of a House of Representatives and a Regional Representatives' Assembly, which is mandated to deal with regional affairs.

Since 1999, Indonesia has had a multiparty system, with no single party able to win a majority. The result has been a succession of coalition governments. The current president, Dr. H. Susilo Bambang Yudhoyono, was elected as the sixth president of Indonesia in 2004 and re-elected for a second term in July 2009. The ruling coalition is a mixture of small parties headed by the Democratic Party. The coalition won the 2009 election with 60.8 per cent of the votes. The ruling coalition's policy stance since its entry to power in 2004 has favoured renewable energy development by altering policies which were seen as hindering development and passing new legislation intended to incentivise interest in the sector. The most important piece of this legislation is the 2007 Renewable Energy Law.

The Democratic Party's competitors in 2009 were a coalition headed by the Indonesian Democratic Party (IDP-P), which won 26.8 per cent of the vote, and a coalition headed by the Golkar party, which won 12.4 per cent of the vote. The Indonesian Center for Indonesian Law was highly critical of these parties in the 2004 elections, noting that they had no platform at all on the environment and sustainable development.[43]

5.4.2 Government Debt

Indonesia's debt-reduction efforts over the period 2002-2009 have been the most impressive of all the ASEAN countries. During this period, the ratio of gross debt to GDP has more than halved, from 64.9 per cent to 28 per cent. In 2009, total external government debt stood at

[43] Down to Earth, Political Parties Disregard Rights, Environment and Sustainable Development, May 2004. Available at <dte.gn.apc.org/61A.HTM>.

USD 150.7 billion. A combination of reforms to promote financial sustainability, strong economic growth, and an expanding tax base imply that the Indonesian fiscal position will strengthen in coming years.[44] In July 2010, ratings agency JCR upgraded Indonesia's sovereign debt to investment grade status.[45]

5.4.3 Targets and Commitments

As a non-Annex I country, Indonesia has no binding GHG emissions reduction target. As part of the Copenhagen Accord, Indonesia set a voluntary target of reducing GHG emissions by 26 per cent by 2020 compared to the 'business-as-usual' projections for that year.[46] Indonesia has also set out a target to have 15 per cent of primary energy consumption come from renewable and alternative energy sources by 2025. This target is further broken down as follows: 5 per cent biofuels, 5 per cent geothermal, and 5 per cent other renewable energy sources and nuclear.[47]

Table 5.13: Indonesian government commitments

GHG emissions	A 2020 government target to cut GHG emission by 26 per cent compared to business-as-usual projections for that year made in 2009.
Renewable energy (RE)	15 per cent of primary energy consumption from renewable and alternative energy sources.
Renewable electricity	None

Source: Indonesian Voluntary Mitigation Actions, Letter to the UNFCCC, 30 January 2010. Available at <unfccc.int/files/meetings/application/pdf/indonesiacphaccord_app2.pdf>; Asian Development Bank, Renewable Energy and Efficiency in Indonesia – Workshop on Climate Change and Energy, 27 March 2009. Available at <www.adb.org/documents/events/2009/Climate-Change-Energy-Workshop/Renewable-Energy-Girianna.pdf>.

5.4.4 Public Sentiment

Energy is heavily subsidised in Indonesia and there is strong public opposition to increasing the retail prices for electricity. In past, reductions in the subsidy levels have led to social unrest. As a result, a move to higher tariffs for renewable power is considered unlikely. The head of Indonesia's National Council on Climate Change has indicated that the future level of subsidies will be below the level that discourages renewable energy, but no details on subsidy reform have been announced.[48]

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[44] World Bank, Indonesia Economic Quarterly, June 2010. Available at <siteresources.worldbank.org/INTINDONESIA/Resources/Publication/280016-1264668827141/6742485-1277258579652/IEQ_June2010_english.pdf>.
[45] Reuters, Japan ratings agency upgrades Indonesia to investment grade, June 2010. Available at <www.reuters.com/article/idUSTOE66C07S20100713>.
[46] Indonesian Voluntary Mitigation Actions, Letter to the UNFCCC, 30 January 2010. Available at <unfccc.int/files/meetings/application/pdf/indonesiacphaccord_app2.pdf>.
[47] Asian Development Bank, Renewable Energy and Efficiency in Indonesia – Workshop on Climate Change and Energy, 27 March 2009. Available at <www.adb.org/documents/events/2009/Climate-Change-Energy-Workshop/Renewable-Energy-Girianna.pdf>.
[48] Reuters, Indonesian official eyes subsidy cuts, June 2010. Available at <www.reuters.com/article/idUSTRE56Q2K620090727>.

5.5 Grid Connection Risk Index

Measure		Value	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	**3/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	1	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other EU countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

5.5.1 Functional Separation

PT Perusahaan Listrik Negara (PLN) is the state-owned utility that holds a monopoly on the provision of transmission and distribution services and the supply of electricity. In 2008, 83 per cent of generating capacity was owned by PLN, with a further 14 per cent accounted for by the 34 IPPs, and the remaining 3 per cent from autoproducers (captive power plants at industrial sites). IPPs are obliged to sell their output to PLN at a negotiated price and cannot sell directly to Indonesian end-users if PLN generation is available in the area at a sufficient and reliable capacity. [49]

The Indonesian power system is currently made up of one large interconnected system for the islands of Java, Bali and Madura (the Java-Madura-Bali, or JAMALI grid). In addition, there are a number of isolated power systems on other islands, usually developed around one load centre. The government determines the tariffs customers pay for electricity and it is heavily subsidised. It was estimated in January 2010 that the government will spend IDR 37.8 trillion (EUR 3 billion) on subsidies for the electricity sector.[50]

5.5.2 Grid Capacity

The JAMALI and Sumatran grids contain an adequate quantity of high-voltage lines and are sufficiently integrated to be well placed to handle the demands that adding extra capacity will place and additional investment in the grids by PLN is ongoing. Outside of these regions, however, the maximum capacity of transmission lines is 150 kV, limiting the scale of projects which can be considered in these areas. The grids in Kalimantan, Nusa Tenggara, Maluku, and Papua will need substantial investment if the government is to achieve its electrification

[49] World Bank presentation on Landfill Gas. Available at <siteresources.worldbank.org/INTINDONESIA/Resources/226271-1125376763288/1607524-1125376945368/1607526-1126767518130/Energy.ppt#280,6,Slide 6>.
[50] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

targets.[51] Table 5.14 sets out the state of the transmission infrastructure in the Indonesian islands, providing an indication of the scale of project which is feasible in the respective regions.

Table 5.14: Length of installed power lines in Indonesia in 2008 (km)

Capacity (kV)	Sumatra	Java-Madura-Bali	Kalimantan	Sulawesi	Nusu Tenggara	Maluku	Papua
500	0	5,092	0	0	0	0	0
275	782	0	0	0	0	0	0
150	8,572	11,844	1,305	1,957	0	0	0
70	334	3,657	123	505	0	0	0
20	72,131	128,364	23,695	23,017	7,473	4,484	1,999
<1	77,431	217,912	21,441	23,795	7,315	2,337	3,531

Source: Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.

5.5.3 Access and Connection Cost

The cost of connecting a renewable project to the grid varies from USD 500 – 30,000 (EUR 377 – 22,620), with connection costs generally much higher outside the JAMAMLI grid area.[52] Under standard PPA agreements, developers are expected to provide a connection to the grid themselves, for which they are later compensated for as part of the PPA agreement in the transmission system use of service charge. However, high grid connections costs are considered to be a barrier to development.[53]

5.6 Planning Permission Risk Index

Measure		Value	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**3/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	1	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	1	

[51] Department of Energy and Mineral Resources, Energy Masterplan 2010-2014, 2010. Available at <www.djlpe.esdm.go.id/modules/_website/files/1030/File/Master%20Plan%20Pembangunan%20Ketenagalistrikan%202010%20s.d.%202014.pdf>.
[52] GSMworld, Grid Connection Costs. Available at <www.gsmworld.com/our-work/mobile_planet/green_power_for_mobile/decision_tree/capex_opex.htm>.
[53] IEA, Deploying Renewables in Southeast Asia, 2010.

5.6.1 Complexity and Expected Timescales

Acquiring the necessary permits to develop a renewable power project in Indonesia is time consuming and complex, with frequent complaints from international investors that the lack of transparency and poor access to information can lead to delays lasting years.[54]

Private power development is implemented in two ways in Indonesia, either by tender, in which investors are invited by the government to bid for the right to operate concessions or by unsolicited proposals which are considered by PLN and the Director General of Energy. Tendering is competitive, and the winner is selected on the basis of the lowest offered price for energy to be bought by PLN.

Private renewable power projects wishing to sell their electricity to the public require permits relating both to IPP and general power plant regulations. The most significant approvals required in Indonesia are the approval by PKLN/Bank Indonesia for foreign currency loans and foreign investment approval by the Investment Coordinating Board, as well as approval of the tariff and PPA by the Ministry of Energy and Mineral Resources. Developers also need to secure the permission of the regional governments.

There is no central coordinating body in Indonesia to assist IPPs with obtaining the necessary regulatory approvals for IPP projects. It is therefore necessary for each IPP to secure regulatory approvals at various levels.[55]

5.6.2 Local Opposition and Procedural Improvements

Given the ongoing need for more power stations to meet demand, there is very little public opposition to any specific form of power plant development.

5.7 Conclusion

Although 5,200 MW of additional renewable capacity is scheduled to be added between 2010-2014, there exists limited potential for renewable energy investors in Indonesia, owing to a complex system of applying for permits, and an unattractive incentive regime which is likely to offer poor returns.

The main area of interest for investors is likely to be the geothermal sector, where there exists immense untapped potential, and where the government is hoping to attract substantial private investment. However, the theoretical maximum price of 73.1 EUR/MWh is considered low and the only solution within the present framework is a time-consuming system of arranging subsidies from the central government budget or from international institutions to allow the project to proceed.

Apart from geothermal, other renewable power technologies present opportunities, particularly solar and biomass power. Again, however, the incentive system does not provide

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[54] 'Red Tape Blocks Clean Energy Investment in Indonesia, Jakarta Globe, May 2010. Available at <www.thejakartaglobe.com/business/red-tape-blocks-clean-energy-investment-in-indonesia-us/377251>.
[55] APEC Energy Working Group, IPP Principles in Indonesia. Available at <apecenergy.tier.org.tw/database/db/ewg20/gndppr/10.3-4.pdf>.

adequate compensation and the government is focussing on small-scale rural electrification projects for these technologies.

The political need to keep high energy subsidies means that the Indonesian government will continue to develop renewable power through PLN or by awarding support to individual projects on a case-by-case basis.

Chapter 6: Japan

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
The primary operating support system is a tradable green certificate system, with a feed-in tariff solely for solar PV production. However, the quota in the TGC system is considered low and there is no support given for emerging technologies.	**2/5**

2. Power Market Opportunities Index	Value
With very little growth in electricity consumption, there is not a pressing need for new generating capacity. However, Japan is almost entirely dependent on imported energy sources to meet demand.	**2/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind, Geothermal
Emerging Technologies Technologies that have growth potential in the country.	Solar PV

Risk Indices

4. Political Will Risk Index	Value
The public and politicians are generally in agreement on renewable energy deployment. However, high debt and support for increased nuclear power deployment could reduce the support given to renewable power.	**3/5**

5. Grid Connection Risk Index	Value
Regional monopolies for generation and transmission may limit development opportunities. However, the grid operators are investing in enhancing the grid network and the government is interested in developing a Smart Grid system.	**2/5**

6. Planning Permission Risk Index	Value
There are very few problems related to securing planning permission. However, protests by local communities over projects can be common.	**1/5**

6.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets*.	1*	**2/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	0	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity*.	1	

* 1 point is awarded for the tradable green certificates. No point has been awarded to the FIT, as its use is limited to electricity generation by small-scale solar PV systems.

6.1.1 Operating Incentives

The Japanese government administers two operating support incentives: a tradable green certificate (TGC) scheme called the Renewable Portfolio Standard (RPS), and a feed-in tariff (FIT) system for small-scale solar PV.

6.1.1.1 Tradable Green Certificates

The RPS was launched in 2003. Under this scheme, renewable power facilities accredited by the Ministry of Economy, Trade and Industry (METI) receive TGCs, called New Energy Certificates (NECs), for their output. The renewable generation sources which are eligible to receive NECs are:

- Solar power
- Wind power
- Biomass
- Small hydro (<1 MW)
- Geothermal.[1]

Demand for renewable electricity and NECs is created by a stipulation of the RPS law which obliges electricity retailers to make up a percentage of their sales volume from renewable energy sources.[2] The size of this percentage depends on the ratio of the government targets for renewable electricity consumption in the current year to the total volume of electricity consumed in the previous year. Government-set targets for renewable electricity consumption are given in Table 6.1. Total electricity consumption in Japan in 2009 was 934,086 GWh. The

[1] Agency for Natural Resources and Energy, Outline of RPS System. Available at <www.rps.go.jp/RPS/new-contents/top/toplink-english.html>.
[2] Government of Japan, The RPS law. Available at <www.rps.go.jp/RPS/new-contents/pdf/rpsjoubun.pdf>.

2010 quota obligation for electricity suppliers is therefore the ratio of the annual target for 2010 (12,200 GWh) to this number, which is 1.3 per cent.

Table 6.1: Renewable electricity targets in Japan from 2010 to 2014

Year	Government target for renewable electricity consumption (GWh)
2010	12,200
2011	13,150
2012	14,100
2013	15,050
2014	16,000

Source: Government of Japan, The RPS law. Available at <www.rps.go.jp/RPS/new-contents/pdf/rpsjoubun.pdf>.

Quota fulfilment is possible by using one of three methods. Electricity suppliers may choose to generate the necessary renewable electricity themselves, or they may purchase NECs from another party. The deadline to demonstrate compliance is 1 June in any given year, but 20 per cent of the annual obligation can be transferred to the following year. Suppliers failing to meet their obligation by the stated deadline may be fined up to JPY 1 million (EUR 8,250[3]) by the Japanese Ministry of Economy, Trade, and Industry (METI).

The quota of renewable power required from electricity suppliers as prescribed by the RPS law is low compared to those of other TGC systems, and the supply of certificates has consistently exceeded the amount required by quota obligations. For this reason, there is no spot market for NECs, and no readily-available pricing information. In 2004, just a year after the operation of RPS began, the supply of certificates exceeded the stated obligation by 57 per cent.[4] To encourage the adoption of solar power, METI ruled in 2010 that NECs from solar power would count double in fulfilling energy suppliers' renewable power quotas.[5]

6.1.1.2 Solar PV Feed-in Tariff

The Japanese FIT system was launched in November 2009 and applies only to small-scale solar PV (see Table 6.2).[6] The FIT rate is fixed for 10 years from the commissioning date of the installation, and is funded by a levy on electricity consumers.[7]

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[3] All conversions done at the rate of EUR 1 = JPY 121.21 (the average of the first six months of 2010).
[4] Nihon No Saise Kano Enerugi Poto Forio Kijyun Seido No Syoki Hyoka' Ritsumeikan Kokusai Kenkyu, Vol 19-2, October 2006. Available at <www.ritsumei.ac.jp/acd/cg/ir/college/bulletin/vol19-2/kimura.pdf>; Tetsuya Iida, 'Keisansyo RPS An no Mondai Ten To Arubeki Seisaku Syudan No Teian', Shizen Enerugi Suishin nettowa-ku. Available at <www.meti.go.jp/report/downloadfiles/g11219g01j.pdf>.
[5] Government of Japan, The RPS law. Available at <www.rps.go.jp/RPS/new-contents/pdf/rpsjoubun.pdf>.
[6] Agency for Natural Resources and Energy, 'Taiyoko Hatsuden No Aratana Kaitori Saito.' (New Buying System for Solar Generation). Available at <www.enecho.meti.go.jp/kaitori/index.html> .
[7] Agency for Natural Resources and Energy, Solar FAQs. Available at <www.enecho.meti.go.jp/kaitori/FAQ.html#1-2>.

Table 6.2: Feed-in tariff rates for solar PV in Japan installed in 2010

Category	Capacity	FIT rate		Duration
		JPY/MWh	EUR/MWH	
Small systems installed by households[a]	<10 kW	48,000	369	10 years
	10-500 kW	24,000	185	
Large systems installed by households[a]	≤500 kW	24,000	185	
Systems installed by non-households	≤500 kW	24,000	185	

Note: [a] 'Households' are defined as 'Houses lived in by family or individuals, including collective houses and houses also used as a commercial property'.
Source: Agency for Natural Resources and Energy, the Ministry of Economy, Trade and Industry, 'Taiyoko Hatsuden No Aratana Kiatori Saito.' Available at <www.enecho.meti.go.jp/kaitori/index.html>.

6.1.2 Investment Support

Grant aid initiatives and tax breaks are periodically launched by NEDO (the New Energy and Industrial Technology Development Organization), METI, the Ministry of the Environment and MAFF (the Ministry of Agriculture, Forestry and Fisheries).[8] Most of these incentives have, however, expired. A recent scheme which provided investment subsidies of 70,000 JPY/kW (577.5 EUR/kW) for solar PV installed by households was closed to new applications on 29 January 2010, and a system of tax breaks potentially worth JPY 100,000 (EUR 825) per household for solar power investments also ended on 31 March 2010.[9]

The Japanese government currently provides a number of investment subsidies.[10] In 2010, the government will continue with its *Heisei 22 Nendo, Shin Enerugi Tou Dounyuu Kasokuka Shien Taisaku Jigyou* (Measures to Promote the Introduction of New Energies). This programme is available to all private businesses introducing renewable energy facilities, including solar, wind, biomass, hydro and geothermal projects. Up to one-third of the investment cost of a project, or up to a maximum of JPY 1 billion, is covered (the exact amount awarded depends on the details of the project). The first application period in 2010 was held between 20 May 2010 and 21 June 2010;[11] however, in 2009 there were five application periods and so more are expected in 2010.

The government has, in previous years, provided the investment subsidies shown below, which are not available in 2010. It is likely, however, that these subsidy schemes will be revived.

In 2007 and 2008, the government provided investment subsidies for hydropower in the 'Subsidy System Relating to Small and Medium Hydro Generation Development' programme for systems between 1,000 kW and 30,000 kW (see Table 6.3).

[8] NEF, "Bio-Nenryo no Ima" (Bio Fuel Now). Available from <www.nef.or.jp/pamphlet/index.html>.
[9] Agency for Natural Resources and Energy, Ashita no tame ni ima shin enerugi (New Energy for tomorrow). Available at <www.enecho.meti.go.jp/energy/newenergy/newene_pamph.htm>; Agency for Natural Resources and Energy, Structural REfor of Investment Programme. Available at <www.eccj.or.jp/enekaku/index.html>.
[10] METI, Subsidies. Available at <www.nedo.go.jp/informations/koubo/190725_1/190725_1.html>.
[11] METI, 平成２２年度新エネルギー等普及促進施策に係る補助事業者の公募について, 2010. Available at <www.nedo.go.jp/informations/koubo/190725_1/190725_1.html>.

Table 6.3: Investment subsidies previously available for hydropower in Japan in 2007 and 2008

Description	Capacity	Maximum subsidy
New construction	1,000-5,000 kW	20 per cent
	5,000-30,000 kW	10 per cent
Repowering	1,000-5,000 kW (increase in output by more than 20 per cent)	20 per cent
	1,000-5,000 kW (increase in output by less than 20 per cent)	Equivalent to the percentage increase in output
	5,000-30,000 kW(increase in output by more than 20 per cent)	10 per cent
	5,000-30,000 kW(increase in output by less than 20 per cent)	Equivalent to half of the percentage increase in output

Source: METI, 中小水力発電開発に係る補助制度. Available at <www.chugoku.meti.go.jp/policy/energy/kobetsu/chushosuiryoku/top.htm>.

The ‘Businesses Promoting Introduction of Local Renewable Energy’ programme in 2007 and 2008 offered subsidies to local and regional public bodies and NGOs to both develop small-scale microgenerators (below 1,000 kW) and to promote the overall development of renewable energy (RE). The following subsidies were available for local and regional public bodies under the programme:

- For building new RE facilities: up to one-third or half of the capital investment costs.
- For the promotion of RE use: maximum of 10 per cent of total costs, up to JPY 5 million per year (and JPY 20 million per applicant for the length of the programme).

For NGOs, the following subsidies are available under the programme:

- For building new RE facilities: up to half of capital investment costs.
- For the promotion of RE use: half of total costs, up to JPY 20 million for the duration of the programme.[12]

There are, however, ongoing subsidies for various technologies, provided by the central government through agencies such as the New Energy Foundation (NEF) and the Japan Photovoltaic Energy Association (JPEA). The NEF has announced plans to introduce a subsidy scheme for research and development in small hydro and geothermal development. The subsidy is planned to cover half of the total research and development costs for small hydropower and geothermal power below 50,000 kW.

Domestic installation of solar PV is encouraged through an income tax break of JPY 100,000 to households that have installed solar PV systems. Some local governments also provide subsidy schemes focused on solar PV which vary regionally and may include cash subsidies, mortgage subsidies, tax breaks, and low interest loans.

The subsidies and loans are also provided for installation of energy efficient systems, such as EcoCute (an energy efficient electric heat pump), ENEFARM (fuel cell cogeneration system), and Ecojyozu (an energy efficient boiler). The national initiatives can be used in combination with local government subsidies to maximize the incentive. Table 6.4 gives examples of central and local government subsidies for solar PV.

[12] Information available at METI, <www.chugoku.meti.go.jp/policy/energy/kobetsu/chushosuiryoku/top.htm>.

Table 6.4: Examples of central and local government subsidies in Japan for solar PV

Technology	Provider	Category	Length	Amount
Solar PV	Central government	Cash contribution	On one occasion	70,000 JPY/kW
		Mortgage tax breaks for construction of new houses	10 years	Yearly tax breaks are given for 1 to 2 per cent of the total amount of the mortgage. The maximum tax break is JPY 5 to 6 million.
		Tax breaks for the reform of existing houses to install energy efficient systems	On one occasion	When solar PV is installed, 10 per cent tax break for the installation fee is given. The maximum tax break is JPY 3 million.
	Tokyo Chiyoda District	Cash contribution	On one occasion	Households: 100,000 JPY/kW, maximum JPY 400,000 per unit. Commercial buildings: JPY 80,000 to 850,000 per unit, maximum JPY 1 million per unit.

Source: J-PEC, Hojyo Seido No Gaiyo. Available at <www.j-pec.or.jp/h21_0202sum.html> and <www.kankyo-business.jp/topix/solar_topix_01.html>.

6.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	0	**2/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	2	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

6.2.1 Energy Consumption

In the era of rapid economic expansion up to the 1970s, Japanese energy consumption grew at a rate higher than GDP growth. However, energy saving measures in the industrial sector was encouraged following the two oil shocks in the 1970s, which lead to energy consumption to grow slower than GDP.[13]

In 2008, primary energy consumption in Japan was 514.4 million tonnes of oil equivalent (Mtoe). Oil was the largest source of primary energy consumption (see Figure 6.1).[14]

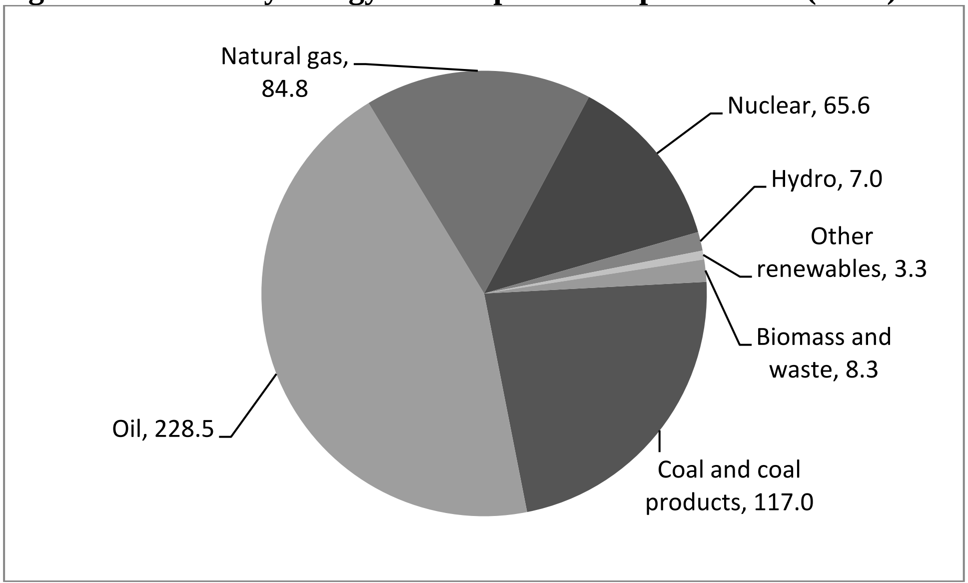
[13] METI, Enerugi Hakusho 2009. Available from <www.enecho.meti.go.jp/topics/hakusho/2009/2.pdf>.
[14] APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.

Between 2000 and 2008, primary energy consumption had a compound annual growth rate (CAGR) of 1.76 per cent.[15]

Japan is dependent on imported energy sources to meet over 96 per cent of its consumption, including all of its oil, gas, coal and uranium.[16] LNG imports in particular increased in recent years. In 2007, LNG imports were equivalent to 282,100 GWh, 32 times the amount in 1973.[17]

Final energy consumption in Japan was 351.7 Mtoe in 2008.[18] Between 2000 and 2008, final energy consumption experienced a CAGR of 0.16 per cent. Industry accounted for 45 per cent of final energy consumption. Due to the development of low energy technology, energy consumption in industry has not increased despite the sector growing 2.3 times in the same period. Furthermore, industrial energy consumption of this sector is gradually declining due to decreased domestic production.[19]

Figure 6.1: Primary energy consumption in Japan in 2008 (Mtoe): Total 514.4 Mtoe



Source: APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.

6.2.2 Electricity Sector

Peak demand in Japan was 181.3 GW in 2007. Peak demand has been increasing slowly and only grew by 9 GW between 2000 and 2007.[20] In addition, since 2007, demand has been decreasing. According to the report by the Federation of Electric Power Companies of Japan (FEPCJ) in October 2009, demand had been decreasing continuously for 13 months, with a

[15] METI, Enerugi Baransu Hyou 2008. Available from <www.enecho.meti.go.jp/info/statistics/jukyu/result-2.htm>.
[16] METI, Enerugi Baransu Hyou 2008. Available from <www.enecho.meti.go.jp/info/statistics/jukyu/result-2.htm>.
[17] METI, Enerugi Hakusho 2009. Available from <www.enecho.meti.go.jp/topics/hakusho/2009/2.pdf>.
[18] METI, Enerugi Baransu Hyou 2008. Available from <www.enecho.meti.go.jp/info/statistics/jukyu/result-2.htm>.
[19] METI, Enerugi Hakusho 2009. Available from <www.enecho.meti.go.jp/topics/hakusho/2009/2.pdf>.
[20] Japan Electric Power Information Centre, Operating and Financial Data. Available at <www.jepic.or.jp/en/data/electr2009.pdf>.

decrease of 6.2 per cent in 2009 compared to the same period in 2008.[21] This decrease is mainly attributed to the declining demand for power by the industrial sector[22] and is the longest period of decline since the collapse of the IT bubble economy in 2000.[23]

The Japanese government expects that there will be a slight increase in the demand for electricity. In their long-term scenario, METI is expecting Japan’s GDP to grow by 1.3 per cent a year between 2005 and 2020, and a further 1.2 per cent between 2020 and 2030. Based on this assumption, electricity demand is expected to increase by 1 per cent a year between 2005 and 2020, and 2 per cent between 2020 and 2030.[24]

Total power consumption was 1,004.5 TWh in 2007. Between 1998 (when consumption was 866.3 TWh) and 2007, electricity consumption has increased at a CAGR of 1.7 per cent.[25] Consumption of electricity has been steadily increasing since the oil shock of 1973, due to the increasing use of air conditioning and electric heaters.[26]

According to METI, in March 2009, Japan had a total installed generating capacity of 237,151 MW from 1,686 generation plants (see Figure 6.2).[27] In the Japanese 2009 financial year (April 2009 to March 2010), total electricity generated was 925,392 GWh, primarily thermal generation from fossil fuels (see Figure 6.3).[28]

Ten privately-owned companies have dominated Japan’s electricity market as regional monopolies. The largest company, Tokyo Electric Power Company (TEPCO), provides 32 per cent of total power generation. The Japanese electricity market was liberalised in 2000. The change to the Electricity Business Act allowed independent power producers (IPPs) to enter the power market. To diversify the procurement of power sources, the government has set up the Japan Electric Power Exchange (JEPE) as a market to trade power supplies.[29] However, the market is still dominated by the companies which existed before the liberalisation and new companies accounts for only 2.37 per cent of the wholesale market. One of the constraints of the market entry for the newcomers are expensive wheeling charges and imbalance fees.[30]

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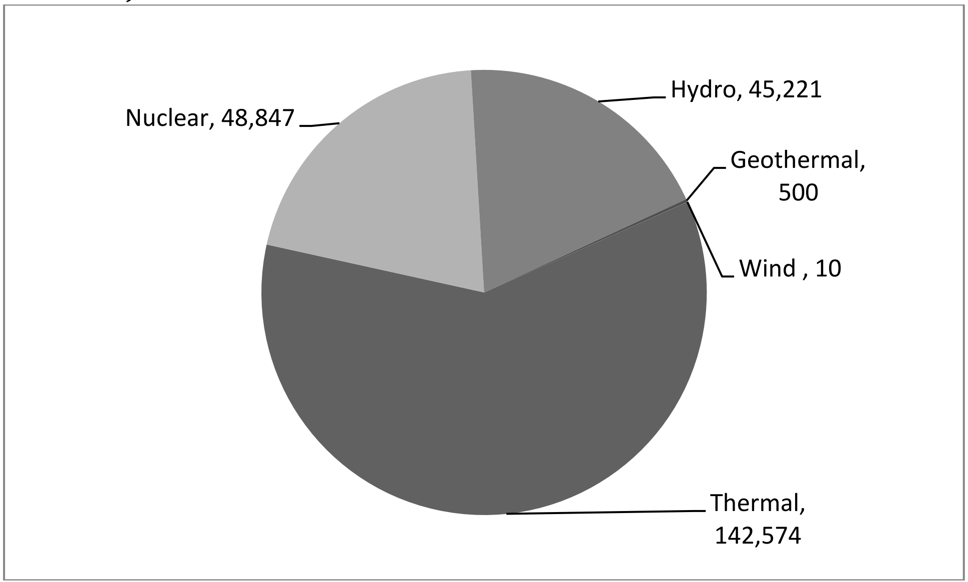
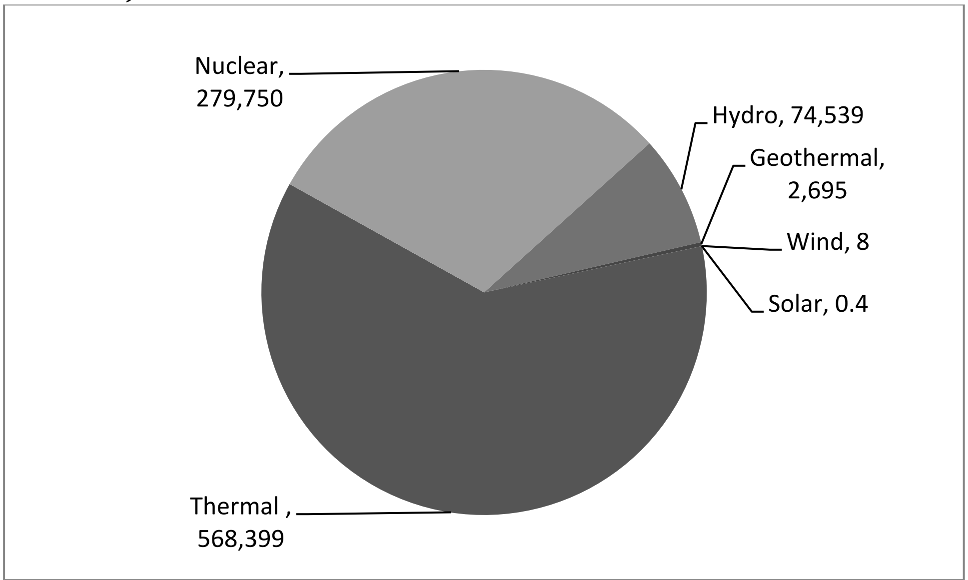
[21] The Federation of Electric Power Companies of Japan, 2009 Nen 10 Gatsu Kakuho, November 2009. Available at <www.fepc.or.jp/library/data/demand/__icsFiles/afieldfile/2009/11/30/kakuho_1130.pdf>.
[22] 47 News, Fukyo De Denryoku Jyuyo Nananen Buri Gensyo He, 6 March 2009. Available at <www.47news.jp/CN/200903/CN2009030601001052.html>
[23] Sankei Shinbun, Heisei 21 nen Kamihan Ki, Denryoku Hanbai Kako Saite, 10 November 2009. Available at <sankei.jp.msn.com/region/kanto/gunma/091110/gnm0911100213001-n1.htm>.
[24] METI, Enerugi Jyukyu No Cyoki Mitooshi. Available at <www.meti.go.jp/report/downloadfiles/g90902a01j.pdf>.
[25] Japan Electric Power Information Centre, Operating and Financial Data. Available at <www.jepic.or.jp/en/data/electr2009.pdf>.
[26] METI, Enerugi Hakusho 2009. Available at <www.enecho.meti.go.jp/topics/hakusho/2009/2.pdf>.
[27] METI, Enerugi Denryoku 2009. Available at <www.enecho.meti.go.jp/info/statistics/denryoku/result-2.htm>.
[28] METI, Heisei 21 Nendo, Hatsuden Jisseki Soukatsu, Available at <www.enecho.meti.go.jp/info/statistics/denryoku/result-2.htm>.
[29] JEPX, Available at < http://www.jepx.org/English/index_e.html>
[30] The Cabinet Office, Wagakuni No Oroshiuri Denryoku Shijyo, 25 April 2007. Available at <www8.cao.go.jp/kisei-kaikaku/minutes/wg/2007/0425/item_070425_07.pdf>.

Figure 6.2: Total installed generating capacity in Japan in 2010 (MW): Total 237,151 MW



Source: METI, Heisei 21 Nendo, Hatsuden Jo, Ninka Shitsuryoku Hyou. Available at <www.enecho.meti.go.jp/info/statistics/denryoku/result-2.htm>.

Figure 6.3: Electricity generation mix in Japan in 2009-2010 (GWh): Total 925,392 GWh



Source, METI, Generation. Available at <www.enecho.meti.go.jp/topics/hakusho/2009energyhtml/p2-1-3-4.htm>.

6.2.3 Nuclear Power

Japan is the third largest generator of nuclear power in the world, after the United States and France, with 55 nuclear reactors operating at the end of 2009.[31] Japan is planning to expand the capacity of nuclear power and build further nuclear plants. The Japan Atomic Agency Commission, a policy unit in the Cabinet office that defines the government's nuclear policy,

[31] The Japan Atomic Energy Forum, Nihon De Katudo Chu No Genshiryoku Hatudensyo. Available at <www.jaif.or.jp/ja/nuclear_world/data/f0302.html>.

published a new a long- and medium-term policy roadmap in 2007.[32] In 2009, the government was planning on constructing four new plants totalling 3.94 GW.[33]

6.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Onshore wind, Geothermal
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV

6.3.1 Renewable Electricity Generation

According to METI, renewable power accounted for 8.3 per cent of total generation in 2009-10. However, 8 per cent was generated from large hydro plants.[34] With the exception of hydropower, solar PV had the largest installed capacity of all renewable power in 2008 and the largest yearly growth rate between 1990 and 2008 (see Table 6.5).

Table 6.5: Growth in the total installed capacity of renewable power in Japan from 1990 to 2008 (MW)

Technology	1990	1995	2000	2006	2007	2008	CAGR 1990-2008
Hydro	37,830	43,456	46,324	47,358	47,313	47,341	1.3%
Geothermal	270	504	533	532	532	532	3.8%
Solar PV	1	43	330	1,709	1,919	2,144	53.1%
Wind	0	1	84	1,805	1,527	1,756	N/A
Municipal waste	0	491	1,322	1,501	1,501	1,501	N/A
Total	38,101	44,495	48,593	52,905	52,792	53,274	1.9%

Note: N/A: Not applicable.
Source: IEA, Renewables Information 2010.

6.3.2 Resource Potential

Depending on location, there are solar irradiation levels of between 4 and 6 kWh/m^2 per day.[35] There are good wind resources in Japan. Table 6.6 shows the average yearly wind speed at a height of 50 metres above ground level in various regions of Japan.

[32] Japan Atomic Agency Commission, Genshiryoku Hakusyo, March 2008. Available at <www.aec.go.jp/jicst/NC/about/hakusho/hakusho2008/index.htm>.
[33] The Japan Atomic Energy Forum, Nihon De Katudo Chu No Genshiryoku Hatudensyo. Available at <www.jaif.or.jp/ja/nuclear_world/data/f0303.html>.
[34] METI, Generation. Available at <www.enecho.meti.go.jp/topics/hakusho/2009energyhtml/p2-1-3-4.htm>.
[35] NASA. 2008. NASA Surface meteorology and Solar Energy (SSE) Release 6.0 Data Set, Clear Sky Insolation Incident On A Horizontal Surface. Available at <eosweb.larc.nasa.gov/sse/>; Hugo Ahlenius, UNEP/GRID-Arendal, Available at <maps.grida.no/go/graphic/natural-resource-solar-power-potential>.

Table 6.6: Average yearly wind speeds in Japan in various regions

Region	Metres/second
Hokkaido	8.31
North-central Honshu	7.71
Western Honshu	7.81
Kyushu	7.5
Okinawa	7.32

Source: A. R. Henderson et al, Potential for Floating Offshore Wind Energy in Japanese Waters, Proceedings of The Twelfth (2002) International Offshore and Polar Engineering Conference, Kitakyushu, Japan, 26-31 May 2002. Available at <www.geni.org/globalenergy/library/energytrends/currentusage/renewable/wind/global-wind-resources/japan/potentialwindjapan.pdf>.

According to METI, 242,300,000 tonnes of biomass was produced in 2005,[36] of which 71 per cent was re-used as fertilizers and cattle feeds, and 20,000,000 tonnes (10 per cent of the total biomass produced) was used for fuel. Therefore, 69,940,000 tonnes of biomass was wasted, which is equivalent to approximately 14,000,000 kl (kilolitres) of crude oil.[37] The potential for biomass as an energy source is high. Table 6.7 shows the breakdown of biomass produced and used in 2005.

Table 6.7: Breakdown of biomass produced and used in Japan in 2005

Biomass	Approximate annual production (10,000 t)	Utility rate and current use	Available resource after use (10,000 t)
Cattle manure	8,900	90% as fertilizer	890
Food waste	2,200	80% as cattle feeding	440
Paper waste	1,600	0% burnt	1,600
Liquid waste (dried weight)	1,400	100% direct fuel	0
Forestry waste	500	90% fertilizer and energy	50
Construction waste	460	60% cattle	184
Logging residue	370	0%	370
Sewage	7,500	64% building material and fertilizer	2,550
Inedible agricultural produces	1,300	30% fertilizer and cattle feeding	910
Total:	24,230	(71.1%)	6994

Source: METI, Shin Enerugi Dounyuu Gaido Kigyou no tame no Baiomasu Dounyuu A to Z. Available from <www.enecho.meti.go.jp/energy/newenergy/newene_pamph.htm>. Translated and calculated by LRI

The main barrier for an effective use of biomass as an energy source is the cost of collection, transportation, and management of biomass that is dispersed across the country.[38] Currently, most biomass is used to make biofuels and the use of biomass to generate electricity is limited.[39]

According to research by the Advanced Industrial Science and Technology (AIST), the potential of geothermal sources with temperature above 150 degree Celsius available in Japan is approximately 23,470 MW. These sources are spread across Japan, with particular potential in areas with short annual daylight hours that discourage the installation of solar PV such as in the Hokuriku, Tohoku, and north-west Japan Sea-side of Hokkaido. Potential geothermal

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[36] METI, Shin Enerugi Dounyuu Gaido Kigyou no tame no Baiomasu Dounyuu A to Z. Available from <www.enecho.meti.go.jp/energy/newenergy/newene_pamph.htm>.
[37] METI, Ashita. Available at <www.enecho.meti.go.jp/energy/newenergy/ashita.pdf>.
[38] NEF, Biomass. Available at <www.nef.or.jp/pamphlet/pdf/05biomass.pdf>.
[39] METI, Biomass. Available at <www.meti.go.jp/kohosys/committee/summary/0000954/index.html>.

development sites, excluding those that fall within national park and areas of special protection, could add up to 4,250 MW. Compared to the current total facilitated capacity of 530 MW, this presents large developmental opportunities in geothermal electricity generation. There are a number of other geothermal sources that could not currently be developed due to low temperatures. Also, most of the potential development sites are located in parks or are used for recreational hot springs, which could become barriers for development.[40]

There are few suitable sites remaining for large hydro development and hence the focus of hydropower development is shifting to small hydro. Japan is rich in water resources and there are many sites appropriate for development of small hydro remaining. Table 6.8 shows the number of sites available for development of small hydro.

Table 6.8: Sites with development potential for small hydro in Japan

Output (KW)	Number of sites		
	Developed	Under construction	Undeveloped
<1,000	450	10	371
1,000-3,000	420	4	1,233
3,000-5,000	168	3	523
5,000-10,000	284	1	340
10,000-30,000	365	4	209
30,000-50,000	90	0	21
50,000-100,000	64	0	14
>100,000	27	1	3

Source: Shigen Enerugi Cho (Agency for Natural Resource and Energy), Suiryoku Kaihatsu no Sokushin Taisaku (Heisei 19 Nendo). Available at <www.enecho.meti.go.jp/energy/newenergy/ashita.pdf>.

6.3.3 Levelised Generation Costs

The FIT system in Japan is currently only available for solar PV and there are no details of generation compensation for other renewable power sources. Table 6.9 compares the levelised generation costs for solar PV in the OECD and the Japan FIT.

Table 6.9: Comparison of feed-in tariff rates in Japan for solar PV with levelised generation costs in the OECD (EUR/MWh)

Technology	FIT rate[a]	Levelised generation costs[b]
Solar PV	185-369	143-408

Notes: [b]Figures based on a 5 per cent discount rate.
[c]The proposed FIT rate under the Jawaharlal Nehru National Solar Mission is used.
Source: [a]See Incentive Opportunities Index above; [b]IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

6.3.4 Wind Power

6.3.4.1 Onshore Wind Power

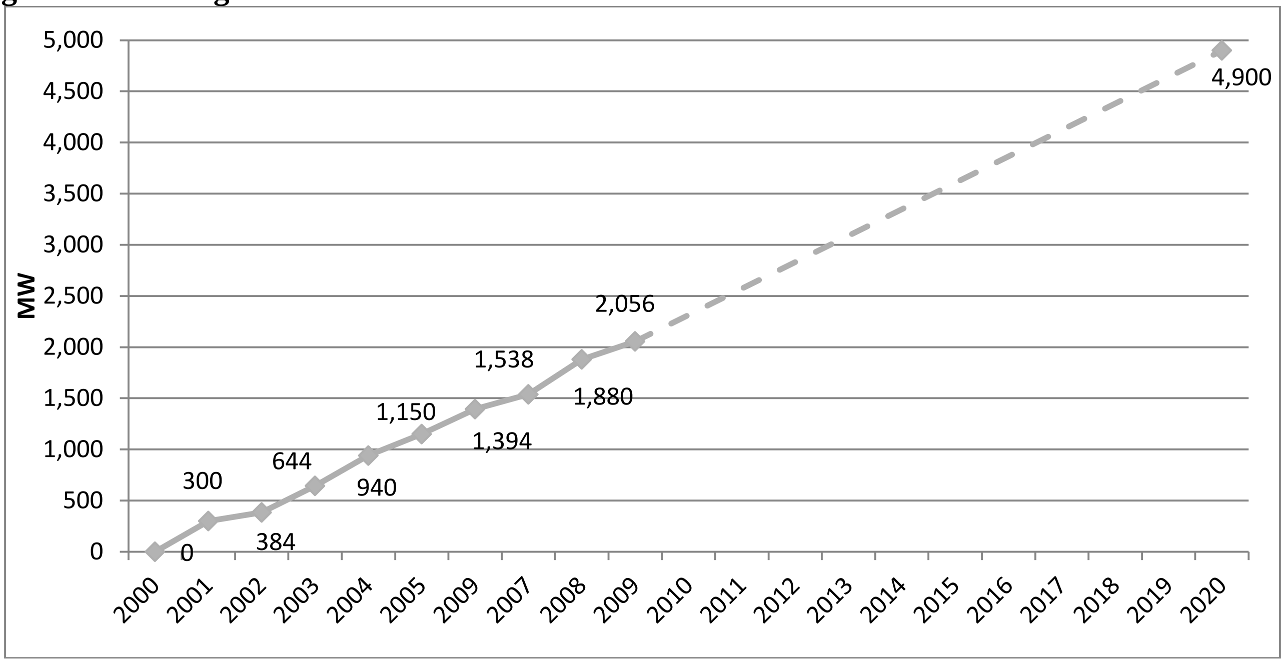
At the end of 2009, Japan had 2,056 MW of wind power installed, a 178 MW increase from 2008 levels. Most of the wind farms are in the north where the wind resources are better (see Table 6.10).[41] The Japanese government has targeted 4,900 MW of wind power capacity by

[40] Midterm report (Chuukan Houkoku) from Jinetsu Hatsuden ni kannsuru Kenkyuukai, published in June 2009. Available at <www.meti.go.jp/committee/summary/0004561/g90609a01j.pdf>; NEF, Geothermal. Available at <www.nef.or.jp/pamphlet/pdf/06geothermal.pdf>.
[41] GWEC, Global Wind Report 2009. Available at <www.gwec.net/index.php?id=167&L=0>.

2020, and 6,600 MW by 2030. Figure 6.4 shows the growth in onshore wind power capacity between 2000 and 2009 and the government's target for 2020.[42] According to the Japan Wind Power Association (JWPA), there is a potential of 65,000 MW of onshore wind power in Japan.[43]

The efficiency of electricity generation through large-scale wind power has been improving in recent years, resulting in levelised generation costs of 10,000-12,000 JPY/MWh (82.50-99.00 EUR/MWh), a rate considered to be highly competitive.[44]

Figure 6.4: Increase in wind power in Japan between 2000 and 2008 and the government target for 2020



Source: METI, 省エネルギー・新エネルギー・原子力への投資の動向. Available at <www.enecho.meti.go.jp/topics/hakusho/2009energyhtml/p1-1-4-2.htm>; METI, Teitanso denryoku kyoukyuu sisutemu no kouchiku ni mukete. Available at <www.meti.go.jp/report/data/g90727ej.html>.

The mountainous topography of Japan with limited flat land, and the lack of excess capacity in the national grid has deterred the development of wind power. However, the introduction of the RPS system and new technical regulations for the grid operators have enabled local companies to sell surplus electricity to electricity companies, encouraging the growth in the installation of wind power stations for commercial purposes.[45]

[42] METI, Teitanso denryoku kyoukyuu sisutemu no kouchiku ni mukete. Available at <www.meti.go.jp/report/data/g90727ej.html>.
[43] Information available at JWPA website at <log.jwpa.jp/category/0000027524.html>.
[44] METI, Teitanso denryoku kyoukyuu sisutemu no kouchiku ni mukete. Available at <www.meti.go.jp/report/data/g90727ej.html>.
[45] METI, Wind power. Available at <www.enecho.meti.go.jp/topics/hakusho/2009energyhtml/p2-1-3-5.htm>.

Table 6.10: Wind farms (>10,000 kW) in Japan as of March 2009

Developer	Technology Provider	Location	Output (kW)	Year and month operational
Dream Up Tomamae	Vestas	Tomamae, Hokkaido	23,100	2000.10
Eurus energy Tomamae	BONUS	Tomamae, Hokkaido	20,000	1999.10
Sarakitonamai Huuryoku	Vestas	Wakkanai, Hokkaido	14,850	2001.10
Tohoku Shizen Energy Kaihatsu	Hitachi Enron	Noshiro Shi, Akita	14,400	2001.11
Eurus energy Iwaya	BONUS	Higashidouri Mura, Aomori	32,500	2001.11
Horonobe Fuuryoku Hatsuden	Lagerwey	Horonobe Cho, Hokkaido	21,000	2001.11
Esashi Wind Power	Lagerwey	Esashi Cho, Hokkaido	21,000	2001.11
Nikaho, Kougen Huuryoku Htsuden, With Vestas	Vestas	Nikaho shi, Akita	24,750	2001.11
Eco Power	NEG-Micon	Rokkasho Mura, Aomori	33,000	2003.1
Eco Power	NEG-Micon	Higashidouri Mura, Aomori	27,000	2003.2
NS Wind Power Hibiki	GE Wind Energy	Kita Kyuushuu Shi, Fukuoka	15,000	2003.3
Minami Kyuushuu Wind Power	IHI-NORDEX	Minami Oosumi Cho, Kagoshima	13,000	2003.3
Aomori Kougen Wind Farm Ltd.	NKK-Lagerway	Iga Shi, Mie	15,000	2003.3
Eurus Energy Yokohama,	Vestas	Yokohama Cho, Aomori	10,500	2003.10
Eurus Energy Shitsukari Hilltop	Vestas	Higashidouri Mura, Aomori	19,250	2003.10
Seto Windhill	Mitsubishi Jukougyou	Ikata Cho, Ehime	11,000	2003.10
Rokkasho Mura, Fuuryoku Kaihatsu	GE Wind Energy	Rokkasho Mura, Aomori	30,000	2003.11
Green Power Kuzumaki	Vestas	Kuzumaki Cho, Iwate	21,000	2003.12
Summit Wind Power Sakata	Vestas	Sakata Shi, Yamagata	16,000	2004.1
Eurus Energy Kihoku,	BONUS	Kanoya Shi, Kagoshima	20,800	2004.2
Wind Tech Bounozu	Vestas	Minami Satsuma Shi, Kagoshima	17,500	2004.3
Miniami Kyuushuu Wind Power	IHI-NORDEX	Minami Oosumi Cho, Kagoshima	13,000	2004.3
Hasaki Wind Farm	De Wind	Kamisu Shi, Ibaragi	15,000	2004. 3
Eurus Energy, Odanozawa Wind Park,	BONUS	Higashi Doori Mura, Aomori	13,000	2004.10
Eurus Energy Nishime, With Vestas	Vestas	Yuri Honjo Shi, Akita	30,000	2004.11
Choshi Fuuyoku Kaihatsu,	GE Wind Energy	Choshi Shi, Chiba	13,500	2004.11
Eurus EnergyKamaishi	Mitsubishi Jukougyou	Kamaishi Shi, Iwate	42,000	2004.12
Nagasaki Shikamachi Fuuryoku Hatsuden	Mitsubishi Jukougyou	Shikamachi Cho, Nagawaki	15,000	2005.2
Green Power Aso	Vestas	Nishihara Mura, Kumamoto	17,500	2005.2
Jay-Wind Tahara	Vestas	Tahara Shi, Aichi	22,000	2005.2
Hizen Fuuryoku Hatsuden	GE Wind Energy	Karazu Shi, Saga	12,000	2005.3
Minami Kyuushuu, Green Energy	IHI-Nordex	Kagoshima Shi, Kagoshima	10,400	2005.3
Kusu Wind Farm	Mitsubishi Jukougyou	Kusu Machi, Oita	11,000	2005.3
Tottori Ken, Hokuei Cho	Repower	Hokuei Cho, Tottori	13,500	2005.9
Eurus Energy Souya	Mitsubishi Jukougyou	Wakkanai Shi, Hokkaido	57,000	2005.11
Green Power Setana	Vestas	Setana Cho, Hokkaido	12,000	2005.12

Tottori Ken Kigyou Kyoku,	Gamesa	Tottori Shi, Tottori	16,000	2005.12
Hayama Fuuryoku Hatsuden Jo	Mitsubishi Jukougyou	Tsuno Cho, Kochi	20,000	2006.1
Summit Wind Power	Gamesa	Kashima Shi, Ibaragi	20,000	2006.7
Atsumi Fuuryoku Hatsuden	GE Wind Energy	Tahara Shi, Aichi	10,500	2006.9
CEF Minami Awaji Wind Farm	GE Wind Energy	Minami Awaji Shi, Hyogo	37,500	2006.10
Em Winds Hachiryuu	Repower	Mitane Machi, Akita	25,500	2006.10
Otsuki Wind Power	Mitsubishi Jukougyou	Ootsuki Machi, Kochi	12,000	2006.11
Eurus Energy Satomi	Ecotecnia	Jouriku oota Shi, Ibaragi	10,020	2006.12
Green Power Kooriyama	Enercon	Kooriyam Shi Fukushima	64,000	2006.12
CEF Toyokita Wind Farm	GE Wind Energy	Shimonoseki Shi, Yamaguchi	17,500	2007.1
Yagi Fuuryoku Hatsuden Jo	Ebara Furaidera	Choushi Shi, Chiba	10,500	2007.2
Toyoura Fuuryoku Hatsuden	Enercon	Shimonoseki Shi, Yamaguchi	20,000	2007.1
Azuchi Ooshima Fuuryoku Hatsuden Jo	Vestas	Hirado Shi, Nagasaki	32,000	2007.2
Suzu Fuuryoku Kaihatsu	GE Wind Energy	Suzu Shi, Ishikawa	15,000	2007.3
Kotoura Wind Farm	GE Wind Energy	Kotoura Cho, Tottori	19,500	2007.3
Misaki Wind Power	Mitsubishi Jukougyou	IkataCho Ehime	20,000	2007.3
Kamisu Green Energy	Vestas	Kamisu Shi, Ibaragi	10,000	2007.12
CEF Izu Higashi Izu Wind Farm	GE Wind Energy	Higashi Izu Cho, Shizuoka	15,000	2007.12
Eurus Energy Kitanozawa Cliff	Gamesa	Higashi Doori Mura, Aomori	12,000	2007.12
Eurus Energy Nobeji	Gamesa	Nomeji Machi, Aomori	50,000	2008.2
Suzu Fuuryoku Kaihatsu	GE Wind Energy	Suzu Shi, Ishikawa	15,000	2008.2
CEF Shirataki Yama Wind Farm	GE Wind Energy	Shimonoseki, Yamaguchi	20,000	2008.3
Hizen Furyoku Hatsuden	GE Wind Energy	Karazu Shi, Saga	18,000	2008.3

Source: NEDO, Fuuryoku Hatsuden Dounyuu Ichirann. Available at <www.nedo.go.jp/library/fuuryoku/pdf/01_dounyuu_ichiran.pdf>. Translated by LRI

6.3.4.2 Offshore Wind Power

There are no offshore wind farms in operation or under construction in Japan as of September 2010. According to the Japan Wind Power Association, there is the potential for 29,000 MW of offshore wind farms, plus an additional 39,000 MW for floating wind farms. However, none are expected to be built until after 2015.[46]

6.3.5 Biomass

6.3.5.1 Solid Biomass

The use of biomass as a new energy source in Japan began in 2001 and the government completed a biomass strategy plan in 2002. In 2003, the RPS started and biomass was included as part of the programme.[47] The government, in its 2006 biomass plan, promoted using solid biomass (forestry waste and rice straw) for heat and power in 'Biomass Towns', which are local communities selected as demonstration sites for replacing fossil fuels with

[46] Information available at JWPA website at <log.jwpa.jp/category/0000027524.html>.
[47] MAFF, Biomas. Available at <www.maff.go.jp/j/biomass/pdf/h18_point.pdf>.

biomass, and for the production of biofuels. As of September 2009 there were 219 of the planned 300 biomass towns.[48]

Most biomass combustion is used strictly for local consumption or for heat production. Municipal solid waste combustion for heat and power is more common in Japan, and in 2008 there was a total installed capacity of 1,501 MW.[49]

6.3.5.2 Biogas

Biogas is already distributed through the main natural gas grid by large suppliers of gas such as the Toho Gas and Tokyo Gas.[50] Since 2009, Tokyo Gas has been distributing 1,650,000 m^3N of biogas annually, which is equivalent to 800,000 m^3N of conventional natural gas.[51]

According to the Biogas Process Council, there were 138 biogas plants in Japan in 2005, of which 70 were associated with animal husbandry, 47 with food and waste, and 21 with waste water and sewerage. Many of the biogas plants are run by local councils, for example, Hita City, Oita Prefecture, has a 680-kW plant that began operation in 2006 and processes 80 tonnes a day of cattle manure, garbage, and agricultural sewage.[52]

6.3.6 Solar Energy

6.3.6.1 Solar PV

At the end of 2009, there was 2,627 MW of solar PV installed in Japan, 96 per cent of which was installed on domestic roofs (see Table 6.11). The government's target for solar PV is to have a total installed capacity of 28 MW by 2020, which would represent a CAGR of 24.1 per cent from 2009 levels. As part of the Japanese economic recovery package, the government doubled the 2020 target from 14 GW and restarted its subsidiary programme.[53]

Grid-connected utility-scale solar PV plants are becoming increasingly popular and there are plans for the construction of 30 of the 140 MW plants in various regions of Japan by 2020. Japan is also a large producer of silicon and solar modules (both silicon and thin film), with world leaders such as Sharp, Sanyo, Kyocera, and Mitsubishi. Typical turnkey costs in 2009 for a 3-5 kW residential system, the most common in Japan, was 613 JPY/W, and for systems above 10 kW the average cost was 547 JPY/W.[54]

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[48] MAFF, Japanese Biomass Strategy, November 2009. Available at <www.biomass-asia-workshop.jp/biomassws/06workshop/presentation/01_Saigou.pdf>.
[49] IEA, Renewables Information 2010.
[50] Information from Toho Gas available at <www.tohogas.co.jp/press/650.html>.
[51] Information from Tokyo Gas available at <www.tokyo-gas.co.jp/Press/20091019-02.html>.
[52] Biogas Process Council website. Available at <www.biogas.jp/pdf/b_siori.pdf>.
[53] Masamichi Yamamoto, NEDO, National Survey Report of PV Power Applications in Japan 2009, 28 May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR_2009_Japan_100620.pdf>.
[54] Masamichi Yamamoto, NEDO, National Survey Report of PV Power Applications in Japan 2009, 28 May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR_2009_Japan_100620.pdf>.

Table 6.11: Cumulative installed PV power in Japan from 2005 to 2009 (MW)

Submarket	2005	2006	2007	2008	2009	CAGR (%)
Off-grid domestic	1,148	1,212	1,884	1,923	2,635	23.1
Off-grid non-domestic	85,909	87,376	88,266	88,886	91,988	1.7
Grid-connected domestic	1,331,951	1,617,011	1,823,244	2,044,080	2,521,792	17.3
Grid-connected non-domestic	2,900	2,900	5,500	9,300	10,740	38.7
Total	1,421,908	1,708,499	1,918,894	2,144,189	2,627,155	16.6

Source: Masamichi Yamamoto, NEDO, National Survey Report of PV Power Applications in Japan 2009, 28 May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR_2009_Japan_100620.pdf>.

6.3.6.2 Concentrated Solar-thermal Power

As of September 2010, there are no concentrated solar-thermal power projects operational or under construction in Japan. The government is, however, funding projects in Abu Dhabi and Tunisia.

6.3.7 Small Hydro

Of available sites, approximately 40 per cent, representing 70 per cent of total production potential, were developed by 2009. Remaining potential sites for development are increasingly located in remote areas and are only suitable for smaller sized plants. Hence, the financial viability of constructing such plants is increasingly difficult, and development is slowing down.

The government projects that there are 38 sites for small hydro that could be developed under the current funding system and could provide 1,500 GWh of electricity a year. However, if the funding for small hydro was equal to that of solar or wind power, it is estimated that 182 sites could be developed, supplying 6,100 GWh of power a year.[55]

Furthermore, there is increasing interest in the use of small hydro to utilise the slight difference in elevation in water reservoir for river maintenance, agricultural reservoir, industrial and domestic water supply. There are 560 sites which can technically be developed, with a generation potential of 600 GWh a year.[56]

6.3.8 Geothermal

The first geothermal power plant in Japan, the Matsukawa Hatsuden Jo, built in 1966, is still operating after more than 40 years. However, there have been no plans for new geothermal plants since 1999. Recent reforms in the electricity business have resulted in industrial stakeholders becoming increasingly cautious with investment decisions and this in turn has resulted in businesses pulling out of geothermal electricity generation. Consequently, the output of electricity generated by geothermal plants has declined steadily since its peak in 1999.[57]

[55] METI 水力発電に関する研究会. Available at <www.meti.go.jp/report/downloadfiles/g80725a01j.pdf>.
[56] METI 水力発電に関する研究会. Available at <www.meti.go.jp/report/downloadfiles/g80725a01j.pdf>.
[57] METI, Mid term report (Chuukan Houkoku) from Jinetsu Hatsuden ni kannsuru Kenkyuukai, June 2009. Available at <www.meti.go.jp/committee/summary/0004561/g90609a01j.pdf>.

As of early 2010, Japan had 20 geothermal power plants in 18 locations with a combined capacity of approximately 530 MW. The plants generated a total of 2,752 GWh in 2008.[58] All the geothermal plants in Japan use a binary system, which uses liquid with a low boiling temperature, such as pentane which has a boiling temperature of 36 degrees Celsius, to run a steam turbine.[59] Table 6.12 contains a list of the operating geothermal plants in Japan.

Table 6.12: Geothermal plants in Japan as of 2010

Name	Developer	Location	Output (kW)	Year
Mori	Hokkaido Denryoku	Hokkaido	50,000	1982
Neta (1 and 2)	Tohoku Denryoku	Iwate	50,000 30,000	1978 1996
Uenotai	Tohoku Denryoku	Akita	28,800	1994
Sumikawa	Tohoku Denryoku	Akita	50,000	1995
Yanaizu Nishiyama	Tohoku Denryoku	Fukushima	65,000	1995
Hacchojima	Tokyo Denryoku	Tokyo	3,300	1999
Otake	Kyusu Denryoku	Oita	12,500	1967
Hacchobara (1 and 2)	Kyushu Denryoku	Oita	55,000 55,000 2,000	1977 1990 2006
Takigami	Kyushu Denryoku	Oita	25,000	1996
Yamagawa	Kyushu Denryoku	Kagoshima	30,000	1995
Ogiri	Kyushu Denryoku	Kagoshima	30,000	1996
Onikobe	Dengen Kaihatsu	Miyagi	12,500	1975
Matsukawa	Tohoku Suiryoku Jinetsu	Iwate	23,500	1966
Onuma	Mitsubishi Material	Akita	9,500	1974
Suginoi	Suginoi Hotel	Oita	1,900	2006

Source: Information derived from FEPC website. Available at <www.fepc.or.jp/library/publication/pamphlet/pdf/enekiso08_09.pdf> and the METI website. Available at <www.enecho.meti.go.jp/energy/newenergy/ashita.pdf>.

6.3.9 Marine (Wave/Tidal)

The Japanese government does not include wave and tidal power in the RPS law and hence the potential for development is yet to be fully recognised.

[58] METI, Mid term report (Chuukan Houkoku) from Jinetsu Hatsuden ni kannsuru Kenkyuukai, June 2009. Available at <www.meti.go.jp/committee/summary/0004561/g90609a01j.pdf>.
[59] METI, Geothermal. Available at <www.enecho.meti.go.jp/energy/newenergy/ashita.pdf>.

6.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	1	
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. A high debt ratio may lead to negative change in the incentive policy for renewable energy.	1	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	**3/5**
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

6.4.1 Government Structure

Japan is a parliamentary democracy. After the 30 August 2009 general election, the Democratic Party of Japan (DPJ) became the ruling party in the House of Representatives, the lower house of the Diet of Japan. The DPJ received 42.4 per cent of the proportional block votes cast and hence defeated the Liberal Democratic Party (LDP), which held power almost continuously during the previous 54 years.[60] The DPJ leader and then-Prime Minister, Yukio Hatoyama, launched a series of reform programmes with the aim of boosting the struggling Japanese economy. Hatoyama resigned on 2 June 2010, and was replaced by the former Finance Minister, Naoto Kan. The current government has been promoting the development of renewable energy in order to bring economic growth to Japan.[61]

6.4.2 Government Debt

Due to the global recession and the sizeable fiscal stimulus implemented by the Japanese government, Japan's public debt was estimated at 218 per cent of GDP in 2009, compared to 188 per cent in 2007.[62]

6.4.3 Targets and Commitments

The Japanese government's *Law Concerning the Promotion of the Measures to Cope with Global Warming* provides the framework for Japan's renewable energy (RE) strategy.[63] Together with its *Basic Policy on Economic and Fiscal Reform 2009* it outlines initiatives to

[60] Reuters, Japan Democrats take power, tough challenges loom, 30 August 2009. Available at <www.reuters.com/article/worldNews/idUSTRE57R01R20090830>.
[61] Japan Plots New Green Stimulus Package, Business Green, August 2010. Available at <www.businessgreen.com/business-green/news/2268491/japan-plots-green-stimulus>.
[62] IMF, Japan: Selected Issues, July 2010. Available at <www.imf.org/external/pubs/ft/scr/2010/cr10212.pdf>.
[63] EIC Net, 'Kaisei Chikyuu Ondanka Taisaku no Suishin ni Kansuru Houritsu' (Partial amendments to the Law Concerning the Promotion of the Measures to Cope with Global Warming), September 2003. Available at <www.eic.or.jp/ecoterm/?act=view&serial=3224>.

reduce GHG emissions and encourage greater adoption of power from renewable sources, in line with Japan's Kyoto Protocol and national commitments.[64]

As part of the Copenhagen Accord, in 2010 the Japanese government announced an emissions-reduction target of 25 per cent relative to the 1990 baseline level by 2020 if an international framework can be established.[65] This target represents an ambitious statement of intent, considering that progress towards achieving its existing 2012 target of 6 per cent has been disappointing. Emissions in 2007 were actually up by 9 per cent from the 1990 baseline.[66]

Table 6.13: Japanese government commitments

GHG emissions	A Kyoto Protocol target of a reduction of 6 per cent in emissions in the period 2008-2012, relative to 1990 levels. A Copenhagen Accord target to reduce emissions by 25 per cent from 1990 levels by 2020.[a]
Renewable energy (RE)	A target of 20 per cent of final energy consumption from renewable sources by 2020.
Renewable electricity	A target of 3 per cent of total electricity consumption from renewable electricity sources by 2010, or 12.2 TWh, and a targeted increase of 2,000 per cent in the total installed capacity of solar PV relative to the 2005 level.

Source: The Cabinet Office, Keizai Zaisei Kaikaku No Kihon Hoshin (Basic Policy on Economic and Fiscal Reform), 9 June 2009.
Available at <www.kantei.go.jp/jp/singi/keizai/kakugi/090623kettei.pdf>; [a]Embassy of Japan to Germany, Letter to the UNFCCC, 2010. Available at <unfccc.int>.

6.4.4 Public Sentiment

The Japanese public agrees with the government's commitment to reduce carbon emissions but they prefer less ambitious targets than Hatoyama's 25 per cent target. In a survey conducted in September 2009 by *Yomiuri Shinbun* (a national newspaper), immediately after the DPJ's election victory, 75 per cent of respondents said they supported the carbon emissions reduction target.[67] However, a survey conducted by the Cabinet Office in May 2009 showed that 15.3 per cent of those polled felt that the government should target a 4 per cent reduction from the 2005 emissions level and 45.4 per cent responded that they would prefer a reduction target of 14 per cent from the 2005 emissions level (equal to a reduction of 7 per cent from 1990 emissions level). [68]

Japanese business showed a strong reluctance to embrace Hatoyama's targets.[69] Major companies such as Honda and Shin Nittetsu have expressed concern about the 25 per cent

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[64] Ministry of Environment, Law Concerning the Promotion of the Measures to Cope with Global Warning. Available at <www.env.go.jp/en/laws/global/warming.html>.
[65] Embassy of Japan to Germany, Letter to the UNFCCC, 2010. Available at <unfccc.int/files/meetings/application/pdf/japancphaccord_app1.pdf>.
[66] エネファームは鳩山首相の秘蔵っ子になるか, September 2009. Available at <www.itmedia.co.jp/enterprise/articles/0909/27/news004.html>.
[67] Yomiuri Shinbun, Hatoyama Naikaku Shijiritu 75%, Rekidai 2 I, 17 September 2009. Available at <www.yomiuri.co.jp/politics/news/20090917-OYT1T01097.htm>.
[68] Cabinet Office, Chikyu Ondanka Taisaku No Chuki Mokuhyo Ni Kansuru Seron Chosa, 24 May 2009. Available at <http://www.kantei.go.jp/jp/singi/tikyuu/kaisai/dai09/09siryou1-2.pdf>.
[69] Sankei Shinbun, 25 % Sakugen Mokuhyo Nihon Ha Tossyutsu, 2 December 2009. Available at <sankei.jp.msn.com/economy/business/091202/biz0912022355018-n1.htm>.

target, and are worried that it will negatively impact Japan's economic competitiveness.[70] The Japan Business Federation (*Keidanren*), which is an industry body representing Japan's large-scale companies and the largest Japanese business lobby, has been opposing cuts higher than 6 per cent from 1990 levels. Keidanren argues that Japan should develop new technologies to help curb emissions, rather than just imposing arbitrary reductions to emissions as Japanese industries have already made significant reductions through energy efficient technologies prior to the Kyoto Protocol, and it believes that Japan is reaching breaking point.[71]

In the public-opinion poll conducted by the Japanese Cabinet Office in December 2005 - the latest public-opinion poll with regards to renewable energy, 1.7 per cent of the respondents replied that they were already using solar PV systems to generate electricity; 9.6 per cent replied that even if the operational costs could not be retrieved over the system's life span, they would still introduce it if were environmentally friendly; 37.8 per cent replied that they would install the system if they could retrieve the operational cost by savings from a reduced electricity bill; and 24.1 per cent replied that they were not interested in installing a solar PV system or in using electricity from renewable energy sources. The majority of those who responded negatively to the public opinion poll were from more rural areas and with regard to age they were generally in their 60s and 70s.[72]

Japanese public opinion is generally supportive of nuclear power. In a survey conducted in October 2009, 59.6 per cent of respondents said that they support the expansion of nuclear power, while 16.2 per cent said that they were against it.[73]

6.5 Grid Connection Risk Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Non-Discriminatory Access</td><td>One point if the transmission function is not legally separated from generation.
If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid.</td><td>1</td><td rowspan="4">2/5</td></tr>
<tr><td>Availability and Clarity</td><td>Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.</td><td>1</td></tr>
<tr><td>Costs</td><td>One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.</td><td>0</td></tr>
<tr><td>Investment</td><td>One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.</td><td>0</td></tr>
</table>

[70] Sankei Shinbun, Seisan Katsudo Ni Seiyaku, 8 September 2009. Available at <sankei.jp.msn.com/life/environment/090908/env0909080117000-n1.htm> and <sankei.jp.msn.com/economy/business/090908/biz0909081752014-n1.htm>.
[71] Japan Business Federation, Kyoto Giteisyo Go No Chikyu Ondanka Mondai Ni Kansuru Kokusaiteki Wakugumi NiMukete, 17 April 2007. Available at <www.keidanren.or.jp/japanese/policy/2007/033.pdf>.
[72] 'Heisei 17 Nen do Enerugi ni kansuru yoron chousa.' Available at <www8.cao.go.jp/survey/h17/h17-energy/index.html>.
[73] The Cabinet office, 'Genshiryoku Ni Kansuru Tokubetu Seron Cyosa', October 2009. Available at <www8.cao.go.jp/survey/tokubetu/h21/h21-genshi.pdf>.

6.5.1 Functional Separation

The Japanese power sector is dominated by 10 vertically-integrated regional monopolies. The retail power market is not fully liberalised, and only customers whose contracted power is 50 kW (6 kV) or larger are able to choose their electricity suppliers. For small businesses and domestic households who are connected to the low-voltage distribution network, regional monopolies are the only suppliers of electricity. A wholesale power market was established in 2003. However, the amount of electricity traded in the market is limited to only a few per cent of the country's total generation.[74]

The vertically-integrated regional power companies own and operate both the transmission and distribution networks in their own regional territories. Third party access by an independent power producer (IPP) to the network is legally guaranteed. However, largely due to the RPS system, a renewable power developer must find a buyer of the power produced and therefore a power purchase agreement with the regional utility is required. Under this institutional framework, any competition between independent renewable power developers and regional monopolies cannot be expected.[75]

6.5.2 Grid Capacity

The power grid operated by the nine regional monopolies (excluding Okinawa) in 2008 included 177,530 MW of generating capacity with a combined length of 94,000 km. In 1980, the grid's capacity was 88,140MW and 76,000 km in length.[76] The Japanese grid is vertically divided into 50 Hz and 60 Hz networks in the north-eastern half of Japan and the south-western half of Japan respectively. This division is due to the history of the grid, where a 50 Hz grid was introduced in 1959, and a 60 Hz grid in 1964.[77]

The anticipated growth in electricity generation will require the Japanese government to develop the existing grid to facilitate growth. To achieve this in a sustainable manner, METI has prepared a road map for the development of a 'Smart Grid' system.[78] The development of a Smart Grid, which will allow the flow of electricity to be controlled from both the supply and demand side, will have benefits in increasing available grid capacity for the anticipated growth in renewable power generation, and help stabilize the intermittent flows of electricity by solar PV and wind power. METI has provided six scenarios for the cost of the Smart Grid in the next 10 years and expects to invest between JPY 145 billion to JPY 1,620 billion, which is equivalent to JPY 58 - 901 per month per household or 0.21 - 3 JPY/ kWh. This will include the costs of increasing power lines to accommodate solar PV output, accumulator

[74] METI, Grid. Available at <www.enecho.meti.go.jp/denkihp/genjo/genjo/index.html>.
[75] Eco, News, 電力事情 電力小売り自由化開始から10年　活発な議論の再燃を望む, 12 January 2010. Available at <econews.jp/electric/cat9/10_4.php>.
[76] METI, Teitanso shakai jitsugen no tame no jisedai souhaidenn nettowaaku no kouchiku ni mukete –Jisedai souhaidenn nettowaaku kenkyuukai houkokusho" April 2010. Available at <www.meti.go.jp/report/downloadfiles/g100426a02j.pdf>.
[77] FEPC, Grid. Available at <www.fepc.or.jp/library/publication/pamphlet/pdf/enekiso08_09.pdf>
[78] METI, Teitanso shakai jitsugen no tame no jisedai souhaidenn nettowaaku no kouchiku ni mukete –Jisedai souhaidenn nettowaaku kenkyuukai houkokusho" April 2010. Available at <www.meti.go.jp/report/downloadfiles/g100426a02j.pdf>.

installation, control system installation, cost of electricity loss, and reduction in heat production from conventional thermal power plants.[79]

The investment by the 10 regional monopoly electricity companies in the distribution network peaked in 1993 at JPY 3.5 trillion, and afterwards steadily declined to JPY 996 billion in 2004; however, it has since seen a growing trend, and reached JPY 1.5 trillion in 2009.[80]

6.5.3 Access and Connection Cost

The distribution network is operated by the 10 regional monopoly companies, who also generate electricity. Other generators have the legal right to connect to the regional distribution networks, and the cost of connection for these other generators, including renewable electricity generators, depends on the regional network they wish to connect to. These connection costs are suggested by the regional monopolies, often depending on the connection voltages, and the costs vary on a case-by-case basis.[81] Furthermore, electricity generators must pay an ancillary price for stabilizing the frequency of electricity. Kyuushuu Denryoku has set the ancillary price at 42 JPY/kW as of April 2007, but exempts electricity generated by renewable energy sources from this cost.[82] Tokyo Denryoku has set the ancillary cost at 37 JPY/kW. [83]

6.6 Planning Permission Risk Index

Measure		**Value**	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	0	**1/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	1	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

[79] METI, Teitanso shakai jitsugen no tame no jisedai souhaidenn nettowaaku no kouchiku ni mukete –Jisedai souhaidenn nettowaaku kenkyuukai houkokusho” April 2010. Available at <www.meti.go.jp/report/downloadfiles/g100426a02j.pdf>.
[80] FEPC, Grid. Available at <www.fepc.or.jp/library/publication/pamphlet/pdf/enekiso08_09.pdf>.
[81] Tohoku Denryoku. Available at <www.tohoku-epco.co.jp/jiyuka/setsuzoku/2-5.htm> and <www.tepco.co.jp/corporateinfo/provide/engineering/wsc/ryoukin-j.html>.
[82] Kyuushuu Denryoku. Available at <www.kyuden.co.jp/company_liberal_servise_03.html>.
[83] Tokyo Denryoku. Available at <www.tepco.co.jp/e-rates/corporate/shin-ene/pdf/100401c.pdf>.

6.6.1 Complexity and Expected Timescales

As well as following the usual industrial planning regulations,[84] an electricity generating facility has to submit a request for a construction permit, or report to METI prior to the construction depending on the perceived impact of the construction on the public safety. Construction of nuclear, tidal and other special plants require construction permits, whilst hydro, solar, thermal and wind generation only need to report to METI.[85] To receive the RPS, the plant must receive separate permission from METI.[86] There are various laws that must be consulted depending on the types of renewable energy used; these include regulations on noise pollution, environmental impact and town planning.

6.6.2 Local Opposition and Procedural Improvements

Wind farms often face severe local opposition, resulting in petitions, such as those at Nyuukasayama in Nagano.[87] These campaigns often focus on ecological issues caused by deforestation and excavation, or the potential harm to, or destruction of, areas of significant historical or scenic value. Campaigners have also complained about the lack of transparency in the development plans for a wind farm at Nyuukasayama. The construction of geothermal plants is also often opposed, largely due to potential impact on national parks or on spas built around hot springs.[88] Opposition for small-hydro plants seems to be less evident in Japan.

6.7 Conclusion

Japan has rich resources for geothermal, solar and biomass power production, although the Japanese government wants to increase its renewable electricity capacity to improve its energy security, which is highly dependent on imported fossil fuels. The Japanese RPS system, however, has been heavily criticized due to its low obligation targets, which do little to create incentives for the electricity supplier to prioritize renewable electricity.

The government offers wide investment incentives, both directed towards businesses and households, for installing renewable power facilities. The Japanese FIT system, however, needs to expand beyond the limits of small-scale solar PV that it currently applies to in order to encourage surplus renewable electricity to be widely available in the market. Furthermore, the Japanese power market is dominated by 10 regional monopolies, and there are concerns regarding the inability of IPPs to compete. The Japanese government is investing large amounts of money in the development of a Smart Grid and in the stabilization of fluctuating electricity outputs generated by the renewable electricity generators. Investment will help with the inclusion of renewable power systems into the grid network, as well as increasing the overall capacity of the grid.

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[84] “Koujou Ricchi Hou” or Law on Industrial Location. Available at <law.e-gov.go.jp/htmldata/S34/S34HO024.html>.
[85] JEEA, Planning. Available at <www.jeea.or.jp/course/contents/11205/> and “Denki Jigyou Hou” (Electricity Business Law). Available at <law.e-gov.go.jp/htmldata/S39/S39HO170.html>.
[86] “Shin Enerugi Riyou tou no Sokushin ni kannsuru Tokubetsu shochi hou” (New Energy Law). Available at <law.e-gov.go.jp/htmldata/H09/H09HO037.html> and “Denki jigyousha ni yoru shin enerugi tou no riyou ni kannsuru tokubetsu shochi hou” (RPS Law). Available at <law.e-gov.go.jp/htmldata/H09/H09HO037.html>.
[87] Wind Farm Protest. Available at <furusato.main.jp/>.
[88] Mainichi Shinbun, 9January 2010. Available at <mainichi.jp/life/ecology/area/gunma/archive/news/2010/01/20100109ddlk10040212000c.html>.

Chapter 7: South Korea (Republic of Korea)

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
A feed-in tariff (FIT) with extra support for emerging technologies remains the primary incentive scheme. However, the FIT system will be replaced with a quota system in 2012.	**5/5**

2. Power Market Opportunities Index	Value
There will be considerable demand for additional capacity by 2020 and South Korea relies heavily upon imported energy sources. However, nuclear power remains likely to play a role in filling the supply gap.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind
Emerging Technologies Technologies that have growth potential in the country.	Solar PV, Offshore wind Marine energy

Risk Indices

4. Political Will Risk Index	Value
There is strong public and political support for renewable energy (RE), and also strong support for nuclear power.	**1/5**

5. Grid Connection Risk Index	Value
The grid remains entirely owned and operated by KEPCO, the state-owned utility, which is also the largest generator. The government is, however, heavily investing in smart grid technology.	**2/5**

6. Planning Permission Risk Index	Value
The government has tried to improve the planning process for renewable energy projects.	**0/5**

7.1 Incentive Opportunities Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Primary Support Mechanism</td><td>Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs).
This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.</td><td>3</td><td rowspan="3">5/5</td></tr>
<tr><td>Duration of Incentives</td><td>One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).</td><td>1</td></tr>
<tr><td>Emerging Technology Support</td><td>One point if the primary support mechanism provides greater relative support for the development of emerging technologies.
A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.</td><td>1</td></tr>
</table>

7.1.1 Operating Incentives

South Korea uses a feed-in tariff (FIT) system as an operating incentive mechanism, as outlined in the 2006 Electricity Business Law. Renewable electricity generators sell their output on the Korean Power Exchange (KPX) and the government compensates eligible renewable power generators for any shortfall between the market price and the FIT rates.[1]

The government guarantees fixed rates for five years for small hydro, biomass and waste and 15 years for wind. Developers have a choice of receiving either 15 or 20 years of support for solar PV. The government controversially changed its tariff regime in 2009, reducing subsidies for large-scale solar PV and capping the amount of new generating facilities that can receive the FIT rates at 50 MW in 2009, 70 MW in 2010, and 80 MW in 2011. From 2009, a degression rate of 4 per cent per annum will be applied to the solar PV tariffs; and from 2010, a degression rate of 2 per cent per annum will be applied to wind power.[2] Tables 7.1 to 7.3 show the FIT rates for renewable power in South Korea.

The FIT system will stop accepting new applicants at the end of 2011 as the government will introduce a quota system in 2012 which will dictate that the power utilities meet a minimum of 2 per cent of consumption with new and renewable power (including fuel cells and integrated gasification coal combustion, IGCC), rising to 4 per cent in 2016, 7 per cent in 2019, and 11 per cent in 2022. It will also require that utilities add 120 MW of solar power every year, rising to 200 MW in 2022. A tradable green certificate (TGC) system will be introduced at the same time, with generation from IGCC plants receiving 0.25 certificates for each MWh supplied, fuel cells receiving 2 certificates for each MWh, and renewable power receiving one certificate. More details are expected late in 2010.[3]

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[1] For more information see the Ministry of Knowledge Economy's website at <www.mke.go.kr>.
[2] IEA, 'Korea's Electricity Business Law'. Available at <www.iea.org/textbase/pm/?mode=re&id=1686&action=detail>.
[3] 'South Korea Assembly Approves Renewable Energy Bill,' Reuters, March 2010.; KENCO, RPS information. Available at <news.kemco.or.kr/main/php/search_view.php?idx=1811>.

Table 7.1: Feed-in tariff rates for non-solar PV renewable power in South Korea in 2010

Category	Capacity	KRW/MWh	EUR/MWh[a]
Wind	Above 10 kW	105,140	69.39
Small hydro	<1 MW	94,640	62.46
	1-5 MW	86,040	56.79
Landfill gas	<20 MW	74,990	49.49
	20-50 MW	68,070	44.93
Biogas	<150 kW	85,710	56.57
	150 kW-50 MW	72,730	48.00
Biomass	<50 MW	68,990	45.53
Tidal	>50 MW	90,500	59.73

Source: Renewable Energy Characteristics of the Korean Electricity Market, 2007. Available at <www.ieadsm.org/Files/Tasks/Task XVII - Integration of Demand Side Management, Energy Efficiency, Distributed Generation and Renewable Energy Sources/Seoul Workshop/Yun.pdf>.
Note: [a]The KRW-EUR conversion rate used is EUR 1 = KRW 0.00066 (the average over the first six months of 2010).

Table 7.2: Feed-in tariff rates for solar PV generated electricity in South Korea from 2008 to 2010 (KRW/MWh)

Commissioning date		Period (years)	< 30 kW	>30 kW			
Up to 30/09/2008		15	711,250	677,380			
01/10/2008-26/08/2009		**Period**	**< 30 kW**	**30-200 kW**	**200 kW – 1 MW**	**1-3 MW**	**> 3 MW**
		15	646,960	620,410	590,870	561,330	472,700
		20	589,640	562,840	536,040	509,240	428,830
From 26/08/2009 onwards	Ground-based	15	566,960	541,420	510,770	485,230	408,620
		20	514,340	491,170	463,370	440,200	370,700
	Building-attached	15	606,640	579,320	546,520	N/A	N/A
		20	550,340	525,550	495,810	N/A	N/A

Source: See Table 7.1.

Table 7.3: Feed-in tariff rates for solar PV generated electricity in South Korea from 2008 to 2010 (EUR/MWh)

Commissioning date		Period (years)	< 30 kW	>30 kW			
to 30/09/2008		15	469.34	477.07			
01/10/2008-26/08/2009		**Period**	**< 30 kW**	**30-200 kW**	**200 kW – 1 MW**	**1-3 MW**	**> 3 MW**
		15	426.99	409.47	389.97	370.48	311.98
		20	389.16	371.47	353.79	336.10	283.03
From 26/08/2009 onwards	Ground-based	15	374.19	357.34	337.11	320.25	269.69
		20	339.46	324.17	305.82	290.53	244.66
	Building-attached	15	400.38	382.35	360.70	N/A	N/A
		20	363.22	346.86	327.23	N/A	N/A

Source: See Table 7.1.

7.1.2 Investment Support

The South Korean government has announced an initiative for its National Renewable Energy Plan in 2009 which earmarked KRW 111.5 trillion (EUR 75 billion) for the promotion of renewable energy between 2010 and 2030. KRW 100 trillion of this (EUR 66 billion) will be used to encourage the adoption of existing technologies, and the remainder will be spent on developing new technologies. The government offers subsidies of up to 80 per cent for a pilot programme, 70 per cent for general deployment of a power plant and 50 per cent for a heat plant. However, a generation project ceases to be eligible to receive the FIT rates for its output if the level of capital subsidy provided by the government exceeds 30 per cent.

A range of loans and tax incentives are available for the purchase of renewable energy equipment and the generation of renewable electricity. Low interest loans are provided by the Korean Energy Management Company (KEMCO) and through local governments. Tax credits of up to 10 per cent of total capital investment are also available.[4] For microgeneration, the government has a 'One Million Green Home Programme' that provides grants for up to 60 per cent of capital costs for a single-family dwelling and up to 100 per cent for multi-family rental accommodation to install small-scale solar, wind and biomass. The government also provides funding for up to 60 per cent of capital costs for solar power units up to 50 kW on public buildings.[5]

As part of a recent economic stimulus package, USD 7 billion in grants is to be provided to new technological developments in renewable energy.[6] In addition, low interest loans are available with a 10-year payment period. There is a 20 per cent tax deduction on equipment purchases and import duties are reduced by 50 per cent for solar thermal, solar PV, wind, hydrogen fuel cells, biomass and marine energy equipment.[7]

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[4] Unescap 2010, 'The Energy Conservation Programme of South Korea'. Available at <www.unescap.org/esd/energy/publications/compend/ceccpart2chapter3.htm>.
[5] Kyung-Hoon Yoon, Korea Institute of Energy Research (KIER), National Survey Report of PV Power Applications in Korea, 2009, International Energy Agency Co-operative Programme on Photovoltaic Power Systems, May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR-Korea-2010.pdf>.
[6] UNEP, Global Trends in Sustainable Energy Investment, 2009. Available at <www.unep.org/pdf/Global_trends_report_2009.pdf>.
[7] APEC Energy Meeting, Sanghoon Lee, New and Renewable Energy Policy in Republic of Korea, 2010. Available at <www.egnret.ewg.apec.org/meetings/engret34/Korea New and Renewable Energy Policy.pdf>

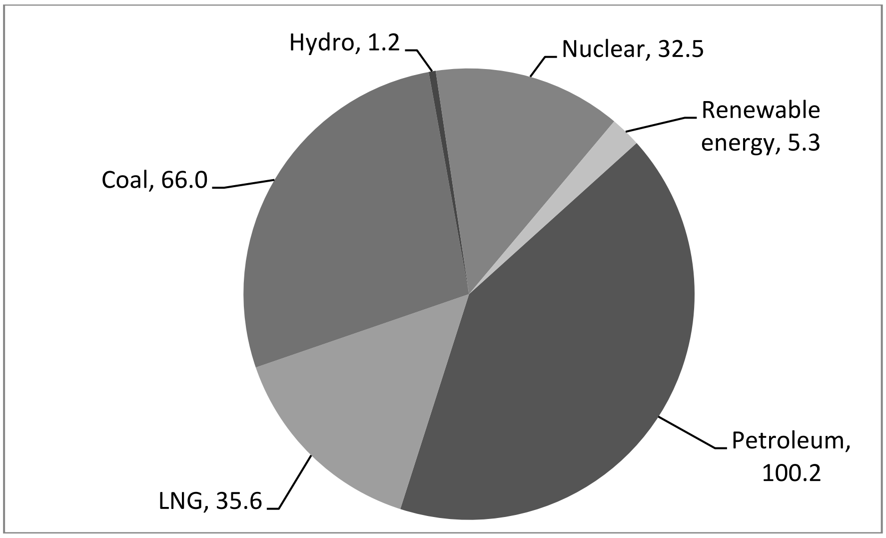
7.2 Power Market Opportunities Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Demand</td><td>Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%).
The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.</td><td>2</td><td rowspan="3">4/5</td></tr>
<tr><td>Security</td><td>Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand.
The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.</td><td>2</td></tr>
<tr><td>Nuclear</td><td>One point if there is an expected decrease of nuclear capacity with no plan of replacement.
If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.</td><td>0</td></tr>
</table>

7.2.1 Energy Consumption

Primary energy consumption totalled 240.8 million tons of oil equivalent (Mtoe) in 2008 (see Figure 7.1), a 1.8 per cent increase from 2007. During the 10 years between 1998 and 2008, primary energy consumption grew at a compound annual growth rate (CAGR) of 3 per cent.[8] With no oil reserves and limited gas and coal reserves, South Korea is one of the largest energy importers in the world. In 2007, 97 per cent of all energy consumption came from imported energy sources.[9] Final energy consumption stood at 182.6 Mtoe in 2008, an increase of 0.6 per cent from 2007.[10] The CAGR of final energy consumption between 1998 and 2008 was 3.29 per cent.

Figure 7.1: Primary energy consumption by source in South Korea in 2008 (Mtoe): Total 240.8 Mtoe



Source: KEEI, Energy Info 2009. Available at <www.keei.re.kr>.

[8] KEEI, Energy Info 2009. Available at <www.keei.re.kr>.
[9] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.
[10] KEEI, Energy Info 2009. Available at <www.keei.re.kr/>.

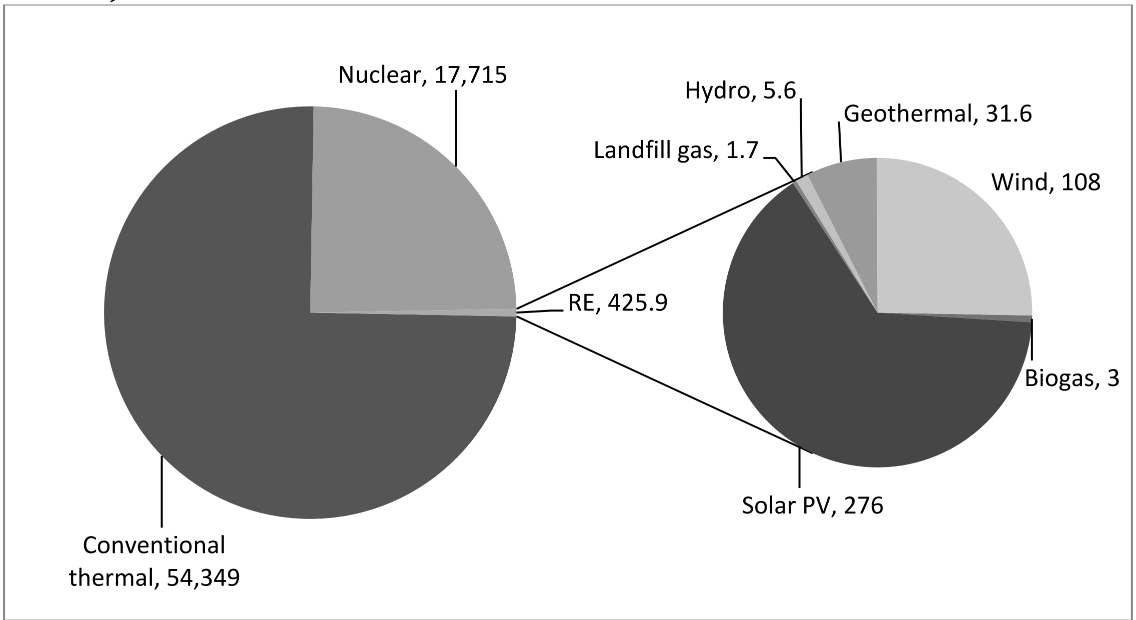
7.2.2 Electricity Sector

Peak demand in 2008 was 62,794 MW, up from 62,285 MW in 2007. Between 1999 and 2008, peak demand grew at a CAGR of 5.96 per cent.[11] By 2020, it is projected that peak demand will reach 75,307 MW, a CAGR of 1.5 per cent from 2008 levels, and then 81,903 MW by 2030, a CAGR of 1.2 per cent from 2008 levels.[12]

Electricity consumption was 385,070 GWh in 2008, an increase of 4.47 per cent from the previous year.[13] Between 1998 and 2008 power consumption grew at a CAGR of 7.13 per cent and is projected to reach 471,706 GWh by 2020, a CAGR of 1.7 per cent from 2008 levels.[14]

In 2008, the last year for which complete statistics are available, total installed generating capacity in South Korea stood at 72,491 MW, 75 per cent of which came from conventional thermal generating capacity (see Figure 7.2). Almost 87 per cent of the generating capacity was owned by Korea Electric Power Corporation (KEPCO), the state-owned power company. The remainder was owned by independent power producers (IPPs). Between 1998 and 2008, the total installed capacity grew at a CAGR of 5.26 per cent, with gas-fired generating capacity seeing the largest growth during the same period.[15]

Figure 7.2: Total installed generating capacity in South Korea in 2008 (MW): Total 72,491 MW



Source: KEEI, Yearbook of Energy Statistics 2009. Available at <www.keei.re.kr/keei/download/YES2009.pdf>.

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[11] KEEI, Yearbook of Energy Statistics 2009. Available at <www.keei.re.kr/keei/download/YES2009.pdf>.
[12] Korean Ministry of Knowledge Economy, The 4th Basic Plan of Long-Term Electricity Supply and Demand (2008-2022), December 2008.
[13] KEEI, 자주 찾는 에너지 통계. Available at <www.keei.re.kr>.
[14] Korean Ministry of Knowledge Economy, The 4th Basic Plan of Long-Term Electricity Supply and Demand (2008-2022), December 2008.
[15] KEEI, Yearbook of Energy Statistics 2009. Available at <www.keei.re.kr/keei/download/YES2009.pdf>.

To meet projected power demand, an additional 33.6 GW of generating capacity is projected to be required by 2022. With the retirement of older generating capacity, total installed generating capacity will amount to 101 GW by 2020 (see Table 7.4). To avoid an increasing reliance on gas imports, nuclear power is projected to account for the majority of the newly installed capacity by 2022.[16]

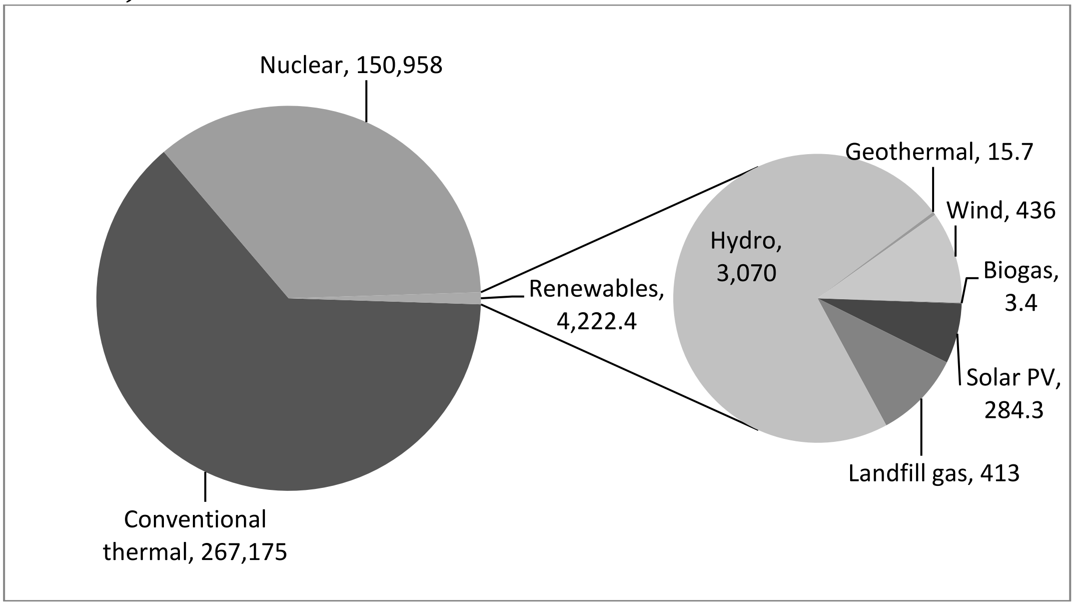
Table 7.4: Projected peak demand and installed generating capacity in South Korea from 2009 to 2022

Year	Peak demand (MW)	Total capacity (MW)		Reserve Margin (%)
		Summer	Year-end	
2009	67,226	72,118	72,543	7.3
2010	69,455	73,552	76,136	5.9
2015	77,214	88,848	93,568	15.1
2020	81,151	100,191	100,191	23.5
2022	81,805	100,891	100,891	23.3

Source: Korean Ministry of Knowledge Economy, The 4th Basic Plan of Long-Term Electricity Supply and Demand (2008-2022), December 2008.

Gross electricity generation amounted to 422,355.4 GWh in 2008, which is an increase of 4.6 per cent from the 403,124.5 GWh generated in 2007. Conventional thermal generation accounted for around 63 per cent of total generation in 2008 (see Figure 7.3).[17]

Figure 7.3: Electricity generation mix in South Korea in 2008 (GWh): Total 422,355.4 GWh



Source: KEEI, Yearbook of Energy Statistics 2009. Available at <www.keei.re.kr/keei/download/YES2009.pdf>.

7.2.3 Nuclear Power

In 2008, there were 20 nuclear reactors totalling 17.7 GW in South Korea and there is strong political support for increasing capacity. Korea Hydro and Nuclear Power Co Ltd, a subsidiary of the state-owned KEPCO, expects to build an additional 18 nuclear plants by

[16] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.
[17] KEEI, Yearbook of Energy Statistics 2009. Available at <www.keei.re.kr/keei/download/YES2009.pdf>.

2030 at a cost of KRW 40-50 trillion (EUR 26.4-33.0 billion), bringing total generating capacity of nuclear power to over 35 GW.[18]

7.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Onshore wind, Solid biomass
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV, Offshore wind Marine energy

7.3.1 Renewable Electricity Generation

With the exception of large hydro, wind and solar PV had the largest installed capacity of all renewable power in South Korea in 2009 (see Table 7.5) and wind power had the highest output of electricity (see Table 7.6). Fuel cells (including those that use renewable and non-renewable sources of fuel) had the largest increase on a year-by-year basis, albeit from a low base.

Table 7.5: Total installed generating capacity of renewable power in South Korea in 2008 and 2009 (MW)

Year	Solar PV	Wind	Small hydro	Fuel cells	Total
2008	159.4	304	73.0	0.6	427.1
2009	429.4	392.1	73.2	20.9	915.6
Growth (%)	169.4	29.0	0.3	3,383.3	114.4

Source: APEC Energy Meeting, Sanghoon Lee, New and Renewable Energy Policy in Republic of Korea, 2010. Available at <www.egnret.ewg.apec.org/meetings/engret34/Korea New and Renewable Energy Policy.pdf>; Korea Power Exchange, Renewable Energy Characteristics on Korea Electricity Market, 2009. Available at <www.ieadsm.org/Files/Tasks/Task XVII - Integration of Demand Side Management, Energy Efficiency, Distributed Generation and Renewable Energy Sources/Seoul Workshop/Yun.pdf>.

Table 7.6: Renewable power generation in South Korea from 2004 to 2008 (MWh)

Year	Biogas	Solar PV	Waste	Wind	Fuel cell	Total
2004	0	13	4,338	20,067	0	24,418
2005	120	422	7,104	104,685	0	112,331
2006	7	3,755	12,584	218,839	290	235,475
2007	1,759	1,9176	29,320	362,198	1,960	414,413
2008	3,556	18,1630	28,965	421,361	13,312	648,824

Source: KEEI, Yearbook of Energy Statistics 2009. Available at <www.keei.re.kr/keei/download/YES2009.pdf>.

[18] World Nuclear Organisation, Country Report: South Korea, August 2010. Available at < www.world-nuclear.org/info/inf81.html>.

7.3.2 Resource Potential

Direct solar irradiation levels in South Korea vary between 2.0 and 4.0 kWh/m2 per day.[19] However, a detailed solar irradiation atlas of South Korea designed to facilitate solar PV development has not been undertaken, although one is due to be completed sometime in 2013.[20]

According to a 1990 study, along the south and west coast of the Korean peninsula the measured annual mean wind speed is about 4-4.5 m/s at the height of 10 m. Jeju Island has particularly good conditions with an average annual mean wind speed of 4.5 m/s at a height of 10 m from ground.[21] A detailed wind atlas of South Korea has not been undertaken, although one is due to be completed in 2013.[22]

Waste and agricultural and forestry residues are the primary biomass resources available in Korea. Table 7.7 details the total biomass resources available in South Korea as of 2007, only 30 per cent of which were used for energy production.

Table 7.7: Biomass resources in South Korea

Resource	Potential resources (in thousands of Mt per year)	Recoverable resources (in thousands of Mt per year)
Forest residues	7,830	1,300
Agricultural residues	16,000	4,900
Food waste	5,100	5,100
Municipal waste	1,600	260
Animal wastes	47,000	N/A
Sludge	2,500	280

Source: Japan Institute of Energy, Biomass Handbook, 2008. Available at <www.jie.or.jp/biomass/AsiaBiomassHandbook/English/All_E-080917.pdf>.

The western and southern coasts of South Korea are suitable for marine energy (wave and tidal power) development. The annual mean wave power in those regions is between 2 and 12 kW per metre of wave.[23] The Garolim and Cheonsu regions, with mean tidal ranges of 4.7 metres and 4.5 metres respectively, are considered prospective sites for tidal power development.[24]

There are significant geothermal resources in Korea, particularly in the southeast of the country. The resources are generally only suitable for heat production due to a relatively low

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[19] NREL, Solar Radiation Levels in Asia. Available at <www.trec-uk.org.uk/resources/asiaDIRnrel_211.pdf>.
[20] Australia Trade Commission and Baker and Mckenzie, Clean and Renewable Energy Market Opportunities in Australia and Korea, May 2010. Available at <www.bakermckenzie.com/files/News/4769bb3d-b368-4afd-8009-9c540d2628a4/Presentation/NewsAttachment/1e97d42d-04aa-45c1-89a5-5f8ee54d6253/bk_cleanrenewableenergymarketopportunitiespart1_may10.pdf>.
[21] FAO, Korean Institute of Since and Technology, Experience on Utilization of Wind Energy in Korea. Available at <www.fao.org/docrep/t4470e/t4470e0r.htm>.
[22] Australia Trade Commission and Baker and Mckenzie, Clean and Renewable Energy Market Opportunities in Australia and Korea, May 2010. Available at <www.bakermckenzie.com/files/News/4769bb3d-b368-4afd-8009-9c540d2628a4/Presentation/NewsAttachment/1e97d42d-04aa-45c1-89a5-5f8ee54d6253/bk_cleanrenewableenergymarketopportunitiespart1_may10.pdf>.
[23] KORDI, Tidal and Tidal Current Power Study in Korea, 2006. Available at <www.oreg.ca/docs/May Symposium/KOREA.pdf>.
[24] RISE, Tidal Barrages. Available at <www.rise.org.au/info/Tech/tidal/index.html>.

heat. New geothermal power technology, however, may be able to use these resources for power production.[25]

7.3.3 Levelised Generation Costs

Table 7.8 compares the levelised generation costs for different technologies in the OECD and the FIT rates in South Korea.

Table 7.8: Comparison of feed-in tariff rates in South Korea with levelised generation costs in the OECD (EUR/MWh)

Technology		FIT rate[a]	Levelised generation costs[b]
Onshore wind		69.39	38-111
Biogas >150 kW		48.00	65
Biomass		45.53	60
Tidal		59.73	195
Solar PV	Ground-based	374.19-269.69	143-408
	BAPV	400.38-360.70	

Notes: [b]Figures based on a 5 per cent discount rate.
Source: [a]See Incentive Opportunities Index above; [b]IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

7.3.4 Wind Power

7.3.4.1 Onshore Wind Power

The government has a target of 7.3 GW of wind power to be installed in the country by 2030, compared to 392 MW at the end of 2009 (see Table 7.9). The estimated potential for onshore wind power in South Korea is 14 GW, with 4.6 GW considered as likely to be developed.[26] To meet the government's 2030 target, wind power will need to grow at a CAGR of 15 per cent between 2009 and 2030. It is expected that an additional 300 MW of wind power will be installed in 2010.[27]

Table 7.9: Total installed capacity of onshore wind in South Korea between 2001 and 2009

Capacity	>2001	2002	2003	2004	2005	2006	2007	2008	2009	CAGR 2001-2009
MW	7.9	12.6	18	68	98	175	193	304	392	63%

Source: IEA Wind, Annual Report 2009: Korea. Available at <www.ieawind.org/AnnualReports_PDF/2009/Korea.pdf>.

The largest wind farm completed in 2009 was the Youngyang wind farm, which is equipped with 41 1.5-MW Acciona wind turbines totalling 61.5 MW of power capacity. Of the 88 MW added in 2009, most of the turbines were imported, primarily from Vestas. However, 8.4 MW

[25] Youngmin Lee et al, Geothermal Resource Assessment for EGS in Korea, Proceedings World Geothermal Congress 2010, 25-29 April 2010. Available at <b-dig.iie.org.mx/BibDig/P10-0464/pdf/3120.pdf>.
[26] Hyun-Goo Kim, Wind Energy Research Center, Korea Institute of Energy Research, Onshore/Offshore Wind Resource Potential of South Korea, 2009. Available at <www.ewec2009proceedings.info/allfiles2/30_EWEC2009presentation.pdf>.
[27] IEA Wind, Annual Report 2009: Korea. Available at <www.ieawind.org/AnnualReports_PDF/2009/Korea.pdf>.

came from locally manufactured turbines and the government is increasing support to local manufacturing companies to produce wind power components, particularly turbines.[28]

7.3.4.2 Offshore Wind Power

There are no commercially operating offshore wind farms in South Korea as of September 2010. In October 2009, the first 3-MW offshore wind turbine was installed near Jeju Island by Doosan Heavy Industries, and after testing, commercial offshore wind farms are expected to be developed in the future. The government has a target of 2 GW of offshore wind farms by 2020.[29] There is potential to develop 13 GW of offshore wind farms around South Korea, with 7.9 GW considered likely to be developed.[30] Table 7.10 details the offshore wind power projects that are under planning. Large South Korean ship builder Daewoo is planning to develop the capacity to build offshore wind turbines with the aim to be the third largest wind turbine supplier by 2020.[31]

Table 7.10: Status of offshore wind power projects in South Korea

Status	Name	Capacity (MW)	Date online
Feasibility study	Taean Offshore Wind Farm	100	2012
Planned by 2015	Jeollanam-do Province	600	2015
	Incheon	97.5	2012

Source: From the Korea Energy Management Corporation. Available at <www.energy.or.kr>.

7.3.5 Biomass

7.3.5.1 Solid Biomass

Solid biomass (including municipal solid waste) is the largest provider of renewable energy in South Korea, although the majority is for heat production in district heating plants.[32] The government is funding up to 48 waste-to-energy treatment plants by 2013 under its economic recovery programme.[33]

7.3.5.2 Biogas

Biogas, primarily landfill gas, is widely used in South Korea. South Korea has 10 large landfills plus a number of smaller ones, and most of the suitable sites already use their gas for power generation and for limited CHP use.[34] An additional 25 landfill gas collecting facilities will also be constructed by 2013 in order to collect the landfill gas from smaller landfills and

[28] IEA Wind, Annual Report 2009: Korea. Available at <www.ieawind.org/AnnualReports_PDF/2009/Korea.pdf>.
[29] IEA Wind, Annual Report 2009: Korea. Available at <www.ieawind.org/AnnualReports_PDF/2009/Korea.pdf>.
[30] Hyun-Goo Kim, Wind Energy Research Center, Korea Institute of Energy Research, Onshore/Offshore Wind Resource Potential of South Korea, 2009. Available at <www.ewec2009proceedings.info/allfiles2/30_EWEC2009presentation.pdf>.
[31] Tom Young, Daewoo Targets Boom in Offshore Wind, Business Green, 25 August 2010. Available at <www.businessgreen.com/business-green/news/2268689/daewoo-targets-wind-energy-boom>.
[32] KEEI, Energy Info 2009. Available at <www.keei.re.k>.
[33] UNEP, Korea's National Strategy for Green Growth, April 2010. Available at <www.unep.org/PDF/PressReleases/201004_UNEP_NATIONAL_STRATEGY.pdf>.
[34] IEA, CHP/DHC Country Scorecard: Republic of Korea. Available at <www.iea.org/g8/chp/profiles/Korea.pdf>.

then to deliver it to power plants.[35] The collecting facilities will allow for more landfill gas to be used in CHP plants as it will be possible to transport the landfill gas to demand centres where the CHP plants are located. Agricultural biogas produced through anaerobic digestion is not as common as landfill gas and has not been promoted to farmers.[36]

7.3.6 Solar Energy

7.3.6.1 Solar PV

At the end of 2009, there was 441.9 MW of solar PV installed in South Korea, 84.4 MW more than at the end of 2008, which was more than a third less than the 276 MW of new solar PV capacity that was installed in 2008, due to the government instituting a capacity cap for FIT eligibility for new systems.

The most important change in the Korean solar PV market in the past five years has been the growth in grid-connected centralised systems, which increased from zero in 2004 to 432.7 MW at the end of 2009. The second largest market is grid-connected distributed systems, primarily placed on residential rooftops. The off-grid market has not increased since 2006 (see Table 7.11).

Table 7.11: Total installed capacity of solar PV in South Korea from 2001 to 2009 (kW)

Description		2001	2002	2003	2004	2005	2006	2007	2008	2009
Off-grid	Domestic	608	608	628	753	853	983	983	983	983
	Non-domestic	3,625	4,041	4,382	4,606	4,810	4,960	4,960	4,960	4,960
Grid-connected	Distributed	524	761	971	3,175	6,551	19,522	36,027	54,852	93,300
	Centralised	0	0	0	0	1,310	10,381	39,223	296,722	432,672
Total		4,757	5,410	5,981	8,534	13,524	35,846	81,193	357,517	441,917

Source: IEA-PVPS, National Survey Report of PV Power Applications in Korea in 2009, May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR-Korea-2010.pdf>.

The most important promotion system for distributed systems in the One Million Green Home Programme, which promotes the construction of solar power, as well as small-scale wind, biomass and fuel cells, in residential buildings until 2020. The government provides 60 per cent of the total investment costs for single-family houses and 100 per cent for large public residential buildings. At the end of 2009, 13.5 MW was connected as a result of the programme. The FIT programme and the quota requirement are the most important incentives for the larger grid-connected centralised systems.[37]

Depending on the type and size of the installed PV system, the price of grid-connected systems varied from 5,850 KRW/W to 7,920 KRW/W (3.86 EUR/W to 5.23 EUR/W).[38]

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[35] UNEP, Korea's National Strategy for Green Growth, April 2010. Available at <www.unep.org/PDF/PressReleases/201004_UNEP_NATIONAL_STRATEGY.pdf>.
[36] IEA, CHP/DHC Country Scorecard: Republic of Korea. Available at <www.iea.org/g8/chp/profiles/Korea.pdf>.
[37] IEA-PVPS, National Survey Report of PV Power Applications in Korea in 2009, May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR-Korea-2010.pdf>.
[38] IEA-PVPS, National Survey Report of PV Power Applications in Korea in 2009, May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR-Korea-2010.pdf>.

The six power generation subsidiaries of KEPCO are set to develop 101.3 MW of solar PV, totalling KRW 338.2 billion (EUR 223 million) from 2009 to 2012. Of that total 51.5 MW will be constructed by KEPCO and 49.8 MW will be constructed by contractors but owned by KEPCO.[39]

The government is also investing in solar panel manufacturing and research and development, primarily of new thin-film solar cells and other new technology.[40] In 2009, KRW 400 billion (EUR 264 million) was invested by different government agencies in research and development and demonstration projects in solar PV, a 47 per cent increase from 2008 levels.[41]

7.3.6.2 Concentrated Solar-thermal Power

As of September 2010 there were no concentrated solar-thermal power projects in operation in South Korea. Daesung Group announced in 2009 that it was examining the feasibility of constructing a 200-kW demonstration CSP tower in Daegu, southeast Korea. The demonstration project will be partially funded by the government.[42]

7.3.7 Small Hydro

The government's Four Rivers Project, a programme to regulate and develop the Han, Nakdong, Geum and Yeongsan river systems, will include small hydro. A total of 42 hydropower projects are set to be developed, although the share of hydropower in the overall energy mix is expected to decline as other RE sources increase.[43]

7.3.8 Geothermal

The use of geothermal energy is projected to increase in South Korea. From supplying 0.009 Mtoe of energy in 2009, primarily heat, geothermal energy production is set to increase to 1.3 Mtoe in 2030, a CAGR of 25.5 per cent.[44]

There are significant geothermal resources in South Korea, especially in the southeast of the country. However, the resources are generally only suitable for heat production due to relatively low heat. New geothermal power technology may be able to use these resources for power production as well.[45]

[39] MKE Renewable Energy Sector, Displaybank, 09/10, 'Korea PV Installment Composition Forecast'.
[40] APEC Energy Meeting, Sanghoon Lee, New and Renewable Energy Policy in Republic of Korea, 2010. Available at <www.egnret.ewg.apec.org/meetings/engret34/Korea New and Renewable Energy Policy.pdf>
[41] IEA-PVPS, National Survey Report of PV Power Applications in Korea in 2009, May 2010. Available at <www.iea-pvps.org/countries/download/nsr09/NSR-Korea-2010.pdf>.
[42] CSP Today, Daegu City Gas Plans Domestic Solar Thermal Power Plant, 2009. Available at <social.csptoday.com/news/daegu-city-gas-plans-domestic-solar-thermal-power-plant>.
[43] UNEP, Korea's National Strategy for Green Growth, April 2010. Available at <www.unep.org/PDF/PressReleases/201004_UNEP_NATIONAL_STRATEGY.pdf>.
[44] UNEP, Korea's National Strategy for Green Growth, April 2010. Available at <www.unep.org/PDF/PressReleases/201004_UNEP_NATIONAL_STRATEGY.pdf>.
[45] Youngmin Lee et al, Geothermal Resource Assessment for EGS in Korea, Proceedings World Geothermal Congress 2010, 25-29 April 2010. Available at <b-dig.iie.org.mx/BibDig/P10-0464/pdf/3120.pdf>.

7.3.9 Marine (Wave/Tidal)

The first tidal power project in South Korea was the 1-MW Uldolmok Plant near Jindo Island, built at a cost of KRW 12.5 billion. It is planned that the plant will be expanded to 90 MW by 2013. A larger project due for completion in late 2010 is the Siwha Tidal Barrage, a 254-MW plant under construction, which will be the largest in the world.[46] Korea Western Power Corporation, a subsidiary of KEPCO, is planning on developing a 520-MW tidal barrage by 2015 (see Table 7.12).[47]

Table 7.12: Status of marine power projects in South Korea

Status	Name	Capacity (MW)	Date online
Completed	Uldolmok Strait Tidal Turbine	1 (90 planned by 2013)	2009
Under construction	Siwha Tidal Barrage	254	2010
Planned	Garorlim Bay Tidal Barrage	520	2015

Source: From the Korea Energy Management Corporation. Available at <www.energy.or.kr>.

7.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. A high debt ratio may lead to negative change in the incentive policy for renewable energy.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	**1/5**
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

7.4.1 Government Structure

In the presidential elections held on 19 December 2007, the former mayor of Seoul, Myung-Bak Lee of the Grand National Party (GNP), won with 48.7 per cent of the votes, a record victory margin. Under the Korean constitution, a president is given a single five-year term and the next election is scheduled to be held in December 2012. The most recent legislative election was held on 9 April 2008, in which the GNP won 172 out of 299 seats, giving the

[46] Korea's Uldolmok tidal power project completed, Wave and Tidal Energy News, 2009. Available at <www.wave-tidal-energy.com/home/news-archive/34-tidal-projects/197-koreas-uldolmok-tidal-power-project-completed>; Kim Hyun-cheol, Koreas First Tidal Plant Completed, Korea Times, 2009. Available at <www.koreatimes.co.kr/www/news/biz/2009/07/123_44894.html>.

[47] S.Korea to invest $1 bln in tidal power plants, Reuters, 25 May 2010. Available at <reuters.com/article/idINTOE62O04K20100325>.

party control of the National Assembly. The next legislative election will be held in April 2012.[48]

Korea launched the Green New Deal on 6 January 2009, a programme which seeks to combine economic recovery with green growth. In July 2009, the government also launched a Five Year Plan for Green Growth for the period 2009 to 2013. Under the plan, USD 83.6 billion, representing 2 per cent of GDP, will be spent in the area of climate change and energy, sustainable transportation and the development of green technologies.[49]

In the last presidential elections, the current president was elected pledging economic reform including further deregulation of the economy and administrative reforms. The president also pledged to increase Korea's GDP by 7 per cent, raise GDP per capita and lead South Korea into position as the world's seventh largest economy within 10 years.[50]

7.4.2 Government Debt

Public sector debt in South Korea was 23.5 per cent of GDP in 2009, down from 24.4 per cent in 2008.[51] The fiscal deficit target was 1.5 per cent of GDP in 2010 (excluding social services funding), down from 4.1 per cent of GDP in 2009, due to the end of some of the programmes in the economic stimulus package. The IMF believes, however, that growth beyond 2011 will fall below pre-2008 levels due to an aging population and highly indebted households and SMEs (small and medium enterprises).[52]

7.4.3 Targets and Commitments

South Korea is a signatory to the Kyoto Protocol; however, it is not an Annex 1 country and hence does not have specific GHG emissions reduction targets specified in the agreement. In 2009 the government set a target of reducing emissions by 30 per cent by 2030 compared to the baseline 'business-as-usual' projections in 2005 (see Table 7.13). This would imply a reduction in GHG emissions of 4 per cent from 2005 levels by 2030. The government's primary RE target is to supply 11 per cent of primary energy consumption from RE by 2030. The 11 per cent target is divided as follows: energy-from-waste, 3.7 per cent; biomass energy, 3.4 per cent; wind power, 1.4 per cent; and others, 2.5 per cent.

Table 7.13: South Korean government commitments

GHG emissions	A government target of reducing emissions by 30 per cent by 2030 compared to the baseline 'business-as-usual' projections in 2005.
Renewable energy (RE)	A government target of 11 per cent of primary energy consumption from renewable sources by 2030.
Renewable electricity	A government target of 10 per cent of total power consumption by 2022.

Source: Korean Ministry of the Environment. Available at <eng.me.go.kr>.

[48] CIA World Factbook; BBC-South Korea Country Profile
[49] UNEP, Korea's National Strategy for Green Growth, April 2010. Available at <www.unep.org/PDF/PressReleases/201004_UNEP_NATIONAL_STRATEGY.pdf>.
[50] AusTrade, Investor Facts: Korea. Available at <www.austrade.gov.au/Republic-of-Korea-profile/default.aspx>.
[51] CIA World Factbook Korea. Available at <www.cia.gov/library/publications/the-world-factbook/geos/ks.html>.
[52] IMF, Republic of Korea: Staff Report for the 2010 Article IV Consultation, 3 August 2010. Available at <www.imf.org/external/pubs/ft/scr/2010/cr10270.pdf>.

7.4.4 Public Sentiment

There is very strong support from the public in South Korea for the reduction of GHG emissions. In a recent opinion poll carried out by the Korea Environmental Policy and Administration Society, 94.8 per cent of respondents acknowledged the seriousness of global warming, 92.9 per cent agreed that emissions had to be cut, and 63 per cent said that they supported the cutting of emissions despite the additional costs. This support extends to nuclear power as well as renewable power.[53]

7.5 Grid Connection Risk Index

Measure		Value	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	**2/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	0	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

7.5.1 Functional Separation

The state-owned KEPCO is the sole transmission and distribution system operator in South Korea and it produces electricity that meets almost 87 per cent of total consumption.[54]

In 2001, the government started to privatise the electricity sector. Part of the plan was implemented, including the establishment of the Korea Power Exchange (KPX) and the Korea Power Commission. The power generation part of KEPCO was split into six subsidiaries, all of which continued to be owned by KEPCO as the general holding company, with a plan to privatise further in the future. In July 2008 the government announced, however, that there would be no further privatisation of KEPCO, and 51 per cent of the company continues to be held by the government. All power generation, including power from KEPCO, is sold on the Korea Power Exchange through a centralised pool system.[55]

[53] 93 per cent of public support emissions cut, YonHap News연합뉴스, 11 March 2010. Available at <app.yonhapnews.co.kr/YNA/Basic/article/new_search/YIBW_showSearchArticle.aspx?searchpart=article&searchtext=%ea%b2%bd%ec%a0%9c%ec%a0%81%20%eb%b6%80%eb%8b%b4&contents_id=AKR20100311138800004>.
[54] See the KEPCO website at <www.kepco.co.kr>.
[55] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

7.5.2 Grid Capacity

There have been no complaints by developers about the lack of available grid capacity. South Korea will invest KRW 27.5 billion (EUR 18 million), KRW 2.7 billion of which will come from the government, to construct a smart grid system throughout the country in order to modernise the power grid. The new grid infrastructure will allow for two-way communication between consumers and generators, and will better allow for the integration of renewable power in the grid system.[56]

7.5.3 Access and Connection Cost

Renewable power plants with capacities of 20 MW or larger are connected to the transmission grid. Those below 20 MW are connected to the distribution grid.[57] The entire costs for connecting to the grid need to be paid for by the developer (deep connection charges).[58] The estimated time for the grid connection requests to be completed is shown in Table 7.14.

Table 7.14: Estimated duration for completion for grid connection request

Process	Transmission grid	Distribution grid
Proposal for connection	4 months	3 months
Acceptance of proposal	2 months	1 month
Completion of grid connection contract	1 month	1 month
Total	7 months	5 months

Source: KEPCO, Rules of use electricity transmission & distribution facilities. Available at <cyber.kepco.co.kr/cyber/03_common/03_knowledgy/agreement/supply_info.html>.

[56] Kim Tae-gyu, Smart Grid Plan Unveiled to Cut Oil Imports, Korea Times, 25 January 2010. Available at <www.koreatimes.co.kr/www/news/biz/2010/01/123_59669.html>; Tom Young, Korea Moves Ahead with Smart Grid Plan, Business Green, 25 January 2010. Available at <www.businessgreen.com/business-green/news/2256676/korea-moves-ahead-smartgrid>.
[57] C. Lin, et al. Challenges of Wind Farms Connection to Future Power Systems in Taiwan/ISESCO Science and Technology Vision, Volume 4, Number 6 (November, 2008). Available at <www.isesco.org.ma/ISESCO_Technology_Vision/NUM06/ISESCO sce 6.pdf/Lin … 37-42.pdf>.
[58] KEPCO, Rules of use electricity transmission & distribution facilities. Available at <cyber.kepco.co.kr/cyber/03_common/03_knowledgy/agreement/supply_info.html>.

7.6 Planning Permission Risk Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Clarity</td><td>One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem.
Complex planning procedures lead to significant delays and costs during the planning process.</td><td>0</td><td rowspan="4">0/5</td></tr>
<tr><td>Time</td><td>Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.</td><td>0</td></tr>
<tr><td>Refusals</td><td>One point if refusal rates are rising or local opposition is clearly delaying projects.</td><td>0</td></tr>
<tr><td>Improvement</td><td>One point if the government is not trying to improve planning procedures even if they are known to be a problem.
Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.</td><td>0</td></tr>
</table>

7.6.1 Complexity and Expected Timescales

Under South Korea's Electricity Enterprises Act, planning application is made to the local government for projects of 3,000 kW or less. For projects over 3,000 kW the application is submitted to the Ministry of Knowledge Economy (MKE). There are, however, no significant differences in the application itself whether it is made to the local or central government. In the entire application process, less than six departments are involved, including the MKE, and KEPCO estimates that the whole procedure will take 60 days.[59] Renewable power plants are given priority in the planning process[60] as part of the government's ongoing effort to simplify the application procedures for energy projects.[61]

7.6.2 Local Opposition and Procedural Improvements

There has been some opposition to wind power development on Jeju Island, one of the best regions of South Korea for wind power development. As developers do not need to go through consultation with neighbours, most of the complaints have centred on compensation and land use.[62]

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[59] KEPCO, Supply Agreement. Available (in Korean) at <cyber.kepco.co.kr/cyber/03_common/03_knowledgy/energy/energy_02.html>.

[60] MKE, 지경부, 신재생에너지 등 신성장동력 산업기반을 확충. Available at <www.mke.go.kr/news/bodo/bodoView.jsp?pCtx=1&seq=56343>.

[61] Today Energy, 신재생 발전소 신설 허가 면제 . Available at <www.todayenergy.kr/news/articleView.html?idxno=50807>.

[62] Gavin Henderson, South Korean Islanders Ask 'Who Owns the Wind?', Ecolocalizer, 2008. Available at <ecolocalizer.com/2008/08/14/south-korean-islanders-ask-who-owns-the-wind/>.

7.7 Conclusion

The South Korean government's recent pledges in the Green New Deal and the Five Year Green Growth Plan illustrate the country's serious commitment towards improving its environmental track record, and this includes the development of the renewable energy sector. Combined with strong demand for electricity there is clearly large potential for renewable energy exploitation in South Korea. Whilst the focus has been given to the traditionally developed areas such as solar and wind, other sources such as tidal power and geothermal, which were virtually non-existent previously, are receiving considerable support.

The planning regime is clear and coherent for developers and there have been no reported difficulties with regards to obtaining a grid connection. For both planning and grid connections, renewable power is given priority.

There are several underlying risks for increasing renewable power deployment. The fund allocated for renewables under the Green New Deal is comparatively less than other areas such as the Four River Restoration Project. In addition, the Korean government's decision to change from the existing FIT system to a RPS system by 2012 has caused a certain degree of concern in the industry.

Chapter 8: Malaysia

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	**Value**
Favourable power purchasing agreements constitute the extent of operating incentives for renewable power. However, the government is proposing moving to a feed-in tariff system in 2011.	**1/5**

2. Power Market Opportunities Index	**Value**
Malaysia is operating from a position of grid oversupply, but new capacity will be needed by 2020. Diversification of the energy supply is also desirable, given rates of resource depletion, but nuclear power is considered likely to be developed.	**3/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Biogas
Emerging Technologies Technologies that have growth potential in the country.	Solar PV

Risk Indices

4. Political Will Risk Index	**Value**
Public support for renewable energy remains adequate, and a 2 per cent levy on electricity usage is unlikely to cause unrest. Previous renewable electricity initiatives have met with limited success, however.	**0/5**

5. Grid Connection Risk Index	**Value**
The balance of power favours utilities against small developers, with no priority access, and grid connection remaining expensive. Improvement is expected in 2011.	**4/5**

6. Planning Permission Risk Index	**Value**
Planning delays can occur due to disagreements with utilities, but permit requirements are not excessive.	**1/5**

8.1 Incentive Opportunities Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Primary Support Mechanism</td><td>Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs).
This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.</td><td>0</td><td rowspan="3">1/5</td></tr>
<tr><td>Duration of Incentives</td><td>One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).</td><td>1</td></tr>
<tr><td>Emerging Technology Support</td><td>One point if the primary support mechanism provides greater relative support for the development of emerging technologies.
A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.</td><td>0</td></tr>
</table>

8.1.1 Operating Incentives

8.1.1.1 Small Renewable Energy Programme

Malaysia does not have any operating incentives to encourage renewable power development. A programme designed to promote renewable power called the Small Renewable Energy Programme (SREP) was launched on 11 May 2001 but the substance of this programme was to codify the conditions that renewable developers needed to fulfil in order to sell their electricity to the local grid rather than to financially incentivise it.

Under the SREP, each renewable energy developer acquires approval and a license from the programme administrator (the Energy Commission of Malaysia, also known as the *Suruhanjaya Tenaga*) before negotiating a price with the local grid operator in the form of the Renewable Energy Power Purchase Agreement (REPPA), which grants the operator of the installation a license to sell electricity to the grid for a duration of 21 years from the date of entering into commercial operation. There are no guidelines to set the range in which the price must be set.

The maximum grid-connected capacity allowed for an SREP project is 10 MW, although a project may be larger if special permission is obtained. The developer is also required to bear all the costs of utility system reinforcements and grid connection works to the main networks. The renewable power plant has to be located within a 10 km radius of the nearest public utility interconnection point, with the exception for mini-hydro generators. All renewable power plants should also be ready for grid-connection within 12 months from the date of approval. An extra condition specific to the Malaysian market is that a minimum 30 per cent equity in a renewable power plant project must be held by *Bumiputera*[1] shareholders, whilst foreign investors are only allowed to participate with a maximum 30 per cent equity share.[2]

The largest public utility in Malaysia mainly operating in the Peninsular, Tenaga Nasional Berhad (TNB), pays a maximum of 210 MYR/MWh,[3] equivalent to 48.09 EUR/MWh.[4] This is generally seen as insufficient to mobilise renewable deployment, and in March 2010, there were only two SREP projects in operation.[5] The rates paid to renewable projects by SESB (a subsidiary of TNB in Sabah) and SESCo (the dominant state-owned utility in Sarawak) were undisclosed.

A recent SREP project, a 10-MW biogas project sourced from tapioca waste by Sediaplas Sdn Bhd was awarded an annual contract worth MYR 18.4 million by TNB for its output. Another project, a 1.25-MW biogas project from Achi Jaya Plantations Sdn Bhd, reached a MYR 2.3 million a year deal for its output with TNB in November 2009, bringing the total capacity under TNB's REPPA contracts to 75.8 MW.[6]

8.1.1.2 Proposed Feed-in Tariff

Disappointing deployment of renewable power following the introduction of the SREP has led to plans for a new Renewable Energy Act which will include a feed-in tariff (FIT) system. The Act is due to be tabled in the parliament in late 2010[7] and come into force in 2011.[8]

Proposed FIT rates were published on 29 July 2010 for solar PV, biomass, biogas and small hydropower (see Table 8.1). For all renewable power plants, the maximum size will be 30 MW. For biomass and biogas systems, domestic feedstock (such as agriculture, forestry residues, solid waste, animal waste, landfill gas and sewage gas) has to be used. The government is not initially including wind and geothermal power in the FIT system as it wants to have a complete survey of wind and geothermal resources completed before deciding on tariff rates.[9]

The Sustainable Energy Development Authority (SEDA) will oversee the implementation of the FIT system. SEDA will pay the renewable power generators from a specially created Renewable Energy Fund which will be funded through a 2 per cent surcharge on electricity

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[1] Literally meaning 'son of the soil', a Bumiputera is an ethnic Malaysian.
[2] Suruhanjaya Tenaga, SREP. Available at <www.st.gov.my/index.php?option=com_content&view=article&id=5245&Itemid=4228&lang=en>.
[3] TNB, TNB Seru Kerajaan Timbang Beri Insentif Kepada Sektor Tenaga Diperbaharui, 12 October 2009. Available at <www.kpdnkk.gov.my/index.php?option=com_content&task=view&id=14081&Itemid=460>.
[4] All currency conversion in this report done at the rate of EUR 1 = MYR 0.22900 (the average of the first six months of 2010).
[5] Suruhanjaya Tenaga, SREP. Available at <www.st.gov.my/index.php?option=com_content&view=article&id=5245&Itemid=4228&lang=en>.
[6] Bursa Station, Signing of Renewable Energy Power Purchase Agreement (REPPA) between Tenaga Nasional Berhad and Achi Jaya Plantations SDN. BHD., 23 November 2009. Available at <bursastation.com/news.pl?action=view_news&id=438749&back=1>.
[7] New Strait Times, Renewable Energy Act to be Tabled in October, 29 June 2010. Available at <www.nst.com.my/nst/articles/RenewableEnergyActtobetabledinOct/Article/>.
[8] Asia Power Times, Malaysia Drafts Renewable Energy Bill, 7 July 2010. Available at <asian-power.com/environment/news/malaysia-drafts-bill-renewable-energy>.
[9] Ministry of Energy, Green Technology and Water, FAQs on the FIT system. Available at <www.mbipv.net.my/dload/FAQs%20on%20FiT.pdf>.

bills.[10] To keep the costs of the FIT system under control, annual funding for new applicants will be set through an annual capacity cap of new entrants into the FIT system. New entrants will enter on a first-come-first-served basis, and once the annual quota for new applicants is filled, other generators must wait until the following year. Table 8.2 shows the annual quota of new entrants that will be allowed into the FIT system. SEDA will be able to change the quota at any time.

Table 8.1: Proposed feed-in tariff rates in Malaysia for 2010

Technology			FIT rate		Duration (years)	Annual degression (%)
			MYR/MWh	EUR/MWh		
Solar PV	Capacity	<4 kW	1,230	281.67	21	10
		4-24 kW	1,200	274.8		
		24-72 kW	1,180	270.22		
		72-1,000 kW	1,140	261.06		
		1,000-10,000 kW	950	217.55		
		10,000-30,000 kW	850	194.65		
	Bonuses	For building-integration	260	59.54		
		Domestically manufactured or assembled modules	30	6.87		
		Domestically manufactured or assembled inverters	10	2.29		
Biomass	Capacity	<10 MW	310	70.99	16	0.5
		10 - 20 MW	290	66.41		
		20 - 30 MW	270	61.83		
	Bonuses	Gasification	20	4.58		
		Steam technology with efficiency >14%	10	2.29		
		Domestically manufactured or assembled gasification	10	2.29		
		Municipal solid waste	100	22.90	16	1.8
Biogas	Capacity	<4 MW	320	73.28	16	0.5
		4 - 10 MW	300	68.70		
		10 - 30 MW	280	64.12		
	Bonuses	gas-engine technology with efficiency >40%	20	4.58		
		domestically manufactured or assembled gas engine	10	2.29		
		landfill or sewage gas	80	18.32	16	1.8
Small hydro	Capacity	<10 MW	240	54.96	21	0
		10-30 MW	230	52.67		

Source: Ministry of Energy, Green Technology and Water, Industry Briefing on Feed-in Tariff Procedures, 29 July 2010. Available at <mbipv.net.my/Re%20Industry%20Briefing%20on%20FiT.PDF>.

Any current SREP facility can apply to enter the FIT system, but they will be treated as any new power system and the time spent operating under the SREP system will be deducted from the duration for which they will be eligible to receive the FIT rates. Biomass and biogas plants will also have to demonstrate that they have adequate fuel supply to meet at least 80

[10] Energy Surge, The Star, 2 March 2010. Available at <thestar.com.my/lifestyle/story.asp?file=/2010/3/2/lifefocus/20100301183741&sec=lifefocus>.

per cent of its planned generation. Foreign participation is limited to 49 per cent of the equity in any given project applying for support under the FIT regime. If the developer had received investment support, the FIT rate received may be reduced, but each project will be evaluated on a case-by-case basis.[11]

Table 8.2: Annual quota of new renewable power capacity that can receive the feed-in tariff rates (MW)

Year	Biomass	Biogas	Small hydro	Solar PV	Solid waste	Total per year
2011	110	20	60	9	20	219
2012	40	15	50	11	30	146
2013	50	15	60	13	40	178
2014	60	25	60	15	50	210
2015	70	25	60	17	60	232
2016	80	25	60	19	40	224
2017	90	30	50	21	40	231
2018	100	30	40	24	30	224
2019	100	30	30	28	30	218
2020	100	25	20	33	20	198

Source: Ministry of Energy, Green Technology and Water, Industry Briefing on Feed-in Tariff Procedures, 29 July 2010. Available at <mbipv.net.my/Re%20Industry%20Briefing%20on%20FiT.PDF>.

8.1.2 Investment Support

Renewable energy projects up to 10 MW are eligible to receive the following incentives:

- Projects can receive 'Pioneer Status' which will give exemption from income tax on 100 per cent of statutory income for 10 years.
- Under the Investment Tax Allowance programme, 100 per cent of qualifying capital expenditures (buildings and equipment) incurred within a period of five years can be distributed five years for tax purposes.
- Renewable energy projects are exempt from import duties on equipment, spare parts and other consumables. Locally purchased equipment is exempt from sales tax. This exemption is granted to a company for one year only.

These incentives are due to expire at the end of 2010 unless the government decides otherwise.[12]

In 2010, the government established a MYR 1.5 billion (EUR 345.5 million) Green Technology Financing Scheme (GTFS) to promote the development of renewable energy by providing loan subsidies and guarantees. The GTFS will pay 2 percentage points of the interest rate, effectively reducing the interest rate faced by investors by 2 percentage points. The government will also guarantee up to 60 per cent of a loan up to MYR 50 million.[13]

The Malaysian Electricity Supply Industries Trust Account (*Akaun Amanah Industri Bekalan Elektrik*, AAIBE) was formed in 1997 and provides financial assistance for rural electrification, energy efficiency and renewable energy projects. Power generators pay 1 per

[11] Ministry of Energy, Green Technology and Water, FAQs on the FIT system. Available at <www.mbipv.net.my/dload/FAQs%20on%20FiT.pdf>.
[12] Buku Panduan Insentif, Incentives. Available at <www.kettha.gov.my/webfm_send/44>.
[13] Budget Speech 2010. Available at <www.treasury.gov.my/bajet2010/bajet2010-vod/data/speech/bs10.pdf>.

cent of their revenue into the AAIBE. Some projects which have attracted AAIBE funding in the past include:

- A grid-connected solar PV roof-top project developed by TNB Research Sdn was awarded 500,000 MYR (99,658 EUR).
- A hybrid diesel-solar PV demonstration project developed by Persatuan Pencinta Alam Malaysia was awarded 472,000 MYR (94,078 EUR)
- A stand-alone hybrid diesel power generation and solar PV system developed at the Education and Research Centre, Endau Rompin National Park.
- 10,000 units of solar PV home systems for a rural electrification scheme.
- A solar PV-powered water pumping system for Milky Stork Breeding in the Kuala Selangor Nature Park.[14]

8.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**3/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	1	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

8.2.1 Energy Consumption

Primary energy supply in Malaysia was 77.4 million tonnes of oil equivalent (Mtoe) in 2008. Not surprisingly given Malaysia's large reserves of natural gas, natural gas comprised over half of primary energy consumption in the same year (see Figure 8.1). Between 2000 and 2008, energy consumption grew at a compound annual growth rate (CAGR) of 5.3 per cent.[15]

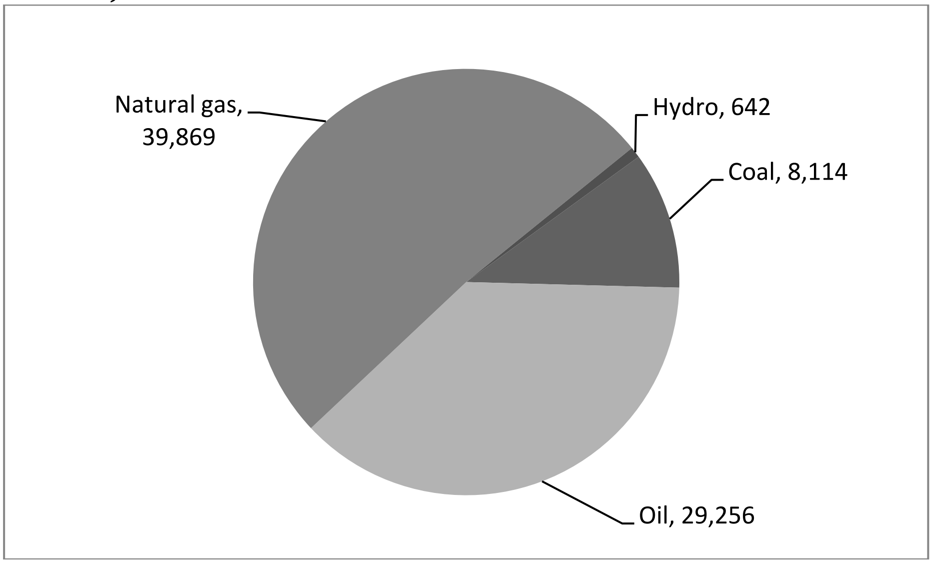
Malaysia is a net exporter of both crude oil and natural gas. However, fields are in decline and it is projected that Malaysia will become a net importer of crude oil by 2015 and of natural gas by 2030.[16] Energy demand in Malaysia is likely to grow at an average annualized rate of 2.2 per cent in the period from 2008-2030,[17] representing a considerable slowing from the rates observed thus far between 2000 and 2008. This reflects a likely increase in the efficiency of energy use by industry, as well as a gradual decrease in population growth and

[14] For more information see the website at <www.kettha.gov.my>.
[15] APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.
[16] IEA, World Energy Review 2009.
[17] IEA, World Energy Outlook 2009

economic growth rates as the Malaysian economy matures. In terms of composition, natural gas is expected to account for an increasing share of power consumption in the years 2010 to 2013.[18]

In 2008, final energy consumption amounted to 44.4 Mtoe. Final energy consumption had a CAGR of 5.2 per cent between 2000, when it stood at 29.7 Mtoe, and 2008.[19]

Figure 8.1: Primary energy consumption by source in Malaysia in 2008 (ktoe): Total 77,389 ktoe



Source: APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.

8.2.2 Electricity Sector

There are three unconnected separate grid systems operating in Malaysia. Tenaga Nasional Berhad (TNB) operates the grid on the Peninsular, while its subsidiary, Sabah Electricity Sdn Bhd (SESB) operates the grid in Sabah, and Syarikat SESCO Berhad operates the grid in Sarawak. All utilities are regulated by the energy commission.[20]

Peak demand throughout all of Malaysia was 15,540 MW in 2008, with the Malay Peninsular having the highest peak demand at 14,007 MW. In Sarawak peak demand was 860 MW and in Sabah 673 MW. In 2000 peak demand amounted to 10,657 MW; therefore, demand had a CAGR of 4.7 per cent between 2000 and 2008.[21] The government projects a peak demand in 2020 of 23,099 MW, based upon an assumed 4 per cent annual growth rate.[22]

Total power consumption (excluding exports) was 92,939 GWh. Between 2003 and 2008 power consumption in Malaysia increased at a CAGR of 5.7 per cent (see Table 8.3).

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[18] IEA, Fuel Options for Power Generation, 2008. Available at <www.iea.org/work/2008/bangkok/malaysia.pdf>.
[19] APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.
[20] Energy Commission, Electricity Supply Industry in Malaysia - Performance & Statistical Information.
[21] Suruhanjaya Tenaga, Statistics. Available at <www.st.gov.my>.
[22] Energy Commission, Electricity Statistics 2005-2008. Available at <www.st.gov.my/index.php?option=com_content&view=article&id=5436%3Aelectricity-statistics&catid=837&Itemid=1749&lang=bm>.

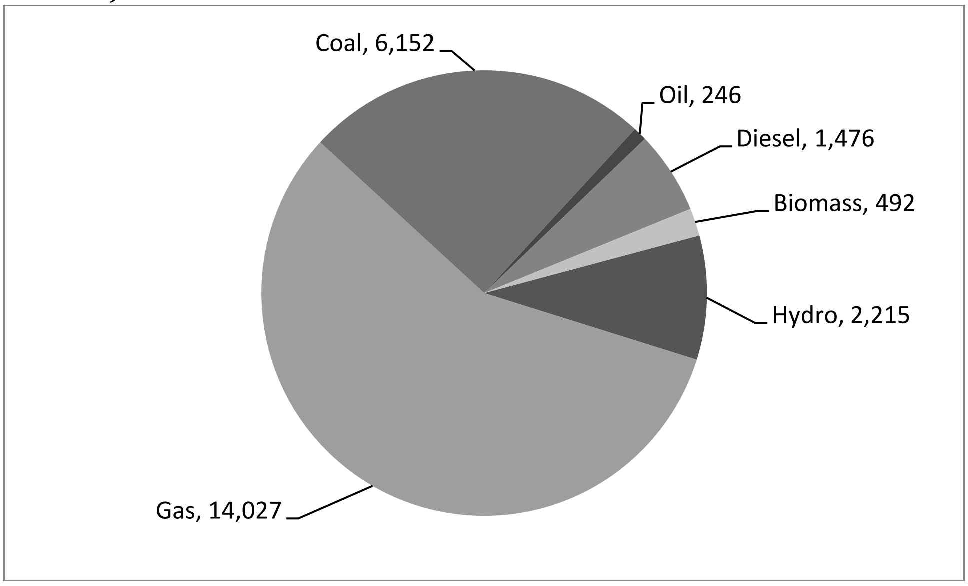
Table 8.3: Power consumption and exports in Malaysia from 2003 to 2008 (GWh)

Year	Consumption in Malaysia	Exports	
		Thailand	Other
2003	70,489	193	0
2004	75,608	605	0
2005	80,241	1,694	0
2006	83,006	2,323	10
2007	87,616	2,477	166
2008	92,939	1,152	214

Source: Suruhanjaya Tenaga, Statistics. Available at <www.st.gov.my>.

Total installed generating capacity in Malaysia was 24,608 MW in 2009. Understandably given the large reserves of natural gas in Malaysia, gas-fired generating capacity accounted for more than 57 per cent of total (see Figure 8.2). The installed capacity of hydropower has been largely stagnant since the early 2000s, and oil-fired power plants are gradually being phased out, except for in remote areas of Malaysia where small diesel generators continue to be the mainstay of generation. The number of coal-fired power plants is projected to rise markedly, due to favourable price differentials relative to other types of generation.[23]

Figure 8.2: Total installed generating capacity in Malaysia in 2009 (MW): Total 24,608 MW



Source: Energy Commission, Statistics 2009. Available at <www.egcfe.ewg.apec.org/publications/proceedings/CFE/Korea_2009/(Session3-B)Coal%20Demand-Supply%20Outlook%20in%20Malaysia.pdf>.

As shown in Table 8.4, the expansion of capacity in the Malaysian grid system has been adequate to meet increased demands placed on it since 2000, although the reduction in the reserve capacity margin from 34.1 per cent in 2000 to 25.7 per cent in 2008 caused concern that power shortages may become an issue by 2015 if more is not invested in increasing generating capacity.[24]

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[23] Energy Commission, Statistics 2009. Available at <www.egcfe.ewg.apec.org/publications/proceedings/CFE/Korea_2009/(Session3-B)Coal%20Demand-Supply%20Outlook%20in%20Malaysia.pdf>.

[24] Elffie Chew, Tenaga Warns of Malaysia Shortage, Wall Street Journal, 22 June 2010. Available at <online.wsj.com/article/NA_WSJ_PUB:SB10001424052748704629804575324031306222918.html>.

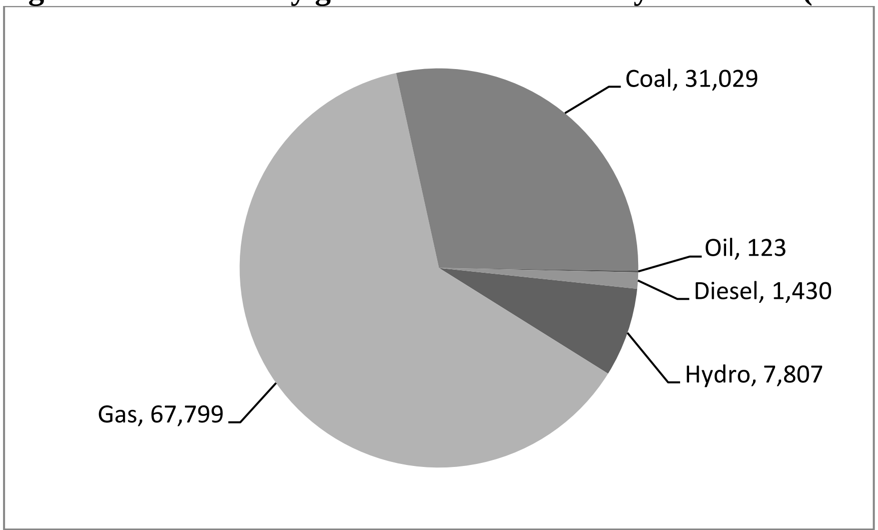
Table 8.4: Growth in peak demand and installed capacity in Malaysia in each grid region

Year	Peninsular Malaysia (TSB)		Sabah (SESB)		Sarawak (SESCO)		Total installed capacity	% growth
	Peak demand	Installed capacity	Peak demand	Installed capacity	Peak demand	Installed capacity		
2003	11,329	17,152	448	770	643	870	18,792	N/A
2004	12,023	20,719	481	770	685	855	22,344	18.90%
2005	12,493	17,426	548	653	743	956	19,035	-14.81%
2006	12,990	18,894	594	757	773	967	20,618	8.32%
2007	13,620	20,247	625	735	834	969	21,951	6.47%
2008	14,007	20,235	673	804	860	1111	22,150	0.91%

Note: N/A: Not available.
Source: Energy Commission, Electricity Statistics 2005-2008. Available at <www.st.gov.my/index.php?option=com_content&view=article&id=5436%3Aelectricity-statistics&catid=837&Itemid=1749&lang=bm>.

Total generation in 2008 amounted to 108,188 GWh, two-thirds of which came from gas-fired generating plants (see Figure 8.3). The government has identified several medium-term generation goals in its 9th Malaysia Plan, including further displacing oil in the generation mix, expanding rural electrification, and encouraging the adoption of renewable energy. High dependence on natural gas will also be addressed by gradually phasing in a greater proportion of coal-fired power plants. Prominent future projects include two independent coal-fired power plants amounting to 3,500 MW under construction in Johor, a 190-MW combined-cycle gas-fired plant and a 300-MW coal-based plant in Sabah, and the 2,400-MW Bakun hydropower project to be commissioned in Sarawak in 2011. Table 8.5 shows the projected change in the electricity generation mix in Malaysia from 2000 to the end of 2010. In the IEA's reference 'business-as-usual' scenario, generation is projected to more than double to 216 TWh by 2030. Total installed generating capacity at the same time is projected to almost double to 47 GW.[25]

Figure 8.3: Electricity generation mix in Malaysia in 2008 (GWh): Total 108,188 GWh



Source: Energy Commission, Electricity Statistics 2005-2008. Available at <www.st.gov.my/index.php?option=com_content&view=article&id=5436%3Aelectricity-statistics&catid=837&Itemid=1749&lang=bm>.

[25] IEA, World Energy Outlook 2009.

Table 8.5: Expected change in the electricity generation mix in Malaysia from 2000 to 2010 (GWh)

Year	Oil	Coal	Gas	Hydro	Others	Total
2000	2,909.8	6,096.6	53,345.6	6,928.0	0.0	692,80.0
2005	2,074.6	20,557.2	66,197.9	5,186.4	282.9	94,299.0
2010	275.8	50,336.8	7,7091.1	7,722.9	24,82.4	137,909.0

Source: Economics Planning Unit, 9th Malaysia Plan, 2008. Available at <www.epu.gov.my/html/themes/epu/html/rm9/english/Chapter19.pdf>.

8.2.3 Nuclear Power

As of September 2010 there were no nuclear power plants in operation or under construction in Malaysia. In May 2010 the government authorised power companies to start identifying locations that would be suitable for nuclear power development. TNB, which expects to complete a plant in 2021 at the earliest, said that nuclear power is necessary for meeting Malaysia's power demand after 2020.[26]

8.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Biogas
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV

8.3.1 Renewable Electricity Generation

Biomass is the largest source of grid-connected renewable power in Malaysia apart from large hydro (see Table 8.6). Wind and solar power have not been exploited in the country.

Table 8.6: Growth in installed generating capacity of renewable power in Malaysia from 2001 to 2008 (MW)

Year	Biomass	Biogas	Municipal solid waste	Mini hydro (<1 MW)	Total
2001	10	2	0	0	12
2002	10	2	0	0	12
2033	30	2	0	0	32
2004	30	2	0	0	32
2005	39	2	0	0	41
2006	39	2	0	0	41
2007	59	2	5.5	0	66.5
2008	74	2	5.5	9	90.5

Source: Suruhanjaya Tenaga, Statistics. Available at <www.st.gov.my>.

[26] Chong Jin Hun, Tenaga 'ready' for nuclear power, Edge Malaysia, 23 September 2010. Available at <www.theedgemalaysia.com/highlights/174078-tenaga-ready-for-nuclear-power.html>.

8.3.2 Resource Potential

Located in close proximity to the equator, Malaysia receives high levels of solar irradiation; averaging 4.5 to 8 hours of sunshine a day, equivalent to of 5.5 kW/m^2 a day.[27]

On average, Malaysia's wind resources are deemed to be poor, with an average wind speed of 2 m/s, which is far below the 7 m/s criterion seen as the benchmark acceptable level for establishing wind farms. Isolated areas with high wind speeds are believed to exist, for instance along the border with Thailand, where wind speeds have been measured to be as high as 15 m/s, but the locations are far removed from demand centres. The potential for offshore wind is not sufficiently high in Malaysia to warrant serious investment in capacity. In a study of regional wind speeds, the region with the highest readings (east Peninsular Malaysia) did not record speeds greater than 4.1 m/s.[28]

Malaysia is rich in potential sources of biomass. It is the world's second largest exporter of palm oil, which is an industry expected to experience steady growth in coming years. Waste products from producing palm oil represent the most important source of biomass potential, while rice, sugar, and forestry waste are other possible contributors. In total, it is estimated that Malaysia's potential is 3,700 MW, of which the Peninsular accounts for 2,400 MW, and Sabah and Sarawak, 900 MW and 360 MW, respectively. In future, it also seems likely that biomass plants burning municipal waste will be built to both deal with Malaysia's waste management and energy problems. Assuming the continuation of current population and waste generation trends, the potential for this type of generation could be as high as 350 MW by 2020, but is liable to be lower should there arise a greater emphasis on recycling municipal waste rather than incinerating it.[29]

Malaysia has abundant hydropower potential estimated at as much as 29,000 MW or 123 TWh/year. Its exploitation is problematic however, as 70 per cent of total capacity is in Sarawak and thus away from areas of high population density. [30] Micro hydro (5-100 kW) is also abundant in potential, with a 2010 study identifying 149 sites with high potential—109 in the Peninsular, 18 in Sabah and 22 in Sarawak.[31]

In a study of Malaysia's marine energy potential, the power recorded at various test sites was shown to be highly variable depending on the season. East Peninsular Malaysia recorded the highest average monthly swell wave power, with a range of 3 – 4.5 kW/m, with Sabah recording a range of 2.1 – 4.2 kW/m and Sarawak recording a range of 3.1 – 4.5 kW/m. The

[27] Hitam S., Sustainable Energy Policy and Strategies 1999. Available at <unpan1.un.org/intradoc/groups/public/documents/apcity/unpan003226.pdf>.
[28] Chiang E. et al, Potential of Renewable Wave and Offshore Wind Energy Resources in Malaysia, 2003. Available at <eprints.usm.my/9180/1/Potential_of_Renewable_Wave_and_Offshore_Wind_Energy_Sources_in_Malaysia_(PPKMekanikal).pdf>.
[29] Malaysia Energy Centre, Biomass in Asia Workshop, 2004. Available at <www.biomass-asia-workshop.jp/biomassws/04workshop/presentation_files/03_Anuar.pdf>
[30] Domingo, N.C, Renewable Resources in South East Asia. Available at <www.ec-asean-greenippnetwork.net/dsp_page.cfm?view=page&select=201>.
[31] Hussein I, Raman M., Reconnaissance Studies of Micro-Hydro Potential in Malaysia, 2010. Available at <esd2010.ueuo.com/esd2010cd/papers/S%2002/S%2002.1_Reconnaissance%20Studies%20of%20Micro%20Hydro.pdf>.

lowest readings were received in West Peninsular Malaysia, which had a range of 1.4 – 2.1 kW/m.[32]

Under the government's proposed FIT system, solar PV and biomass are to account for the bulk of new renewable power capacity built up to 2050 (see Table 8.7). However, growth in new biomass-based power generation is to stabilise in 2030 at 1,340 MW. Solar PV is projected to increase dramatically after 2030.

Table 8.7: Proposed cumulative quota on renewable power capacity in Malaysia under the FIT system (MW)

Year	Biomass	Biogas	Mini hydro	Solar PV	Solid waste	Total
2011	110	20	60	9	20	219
2012	150	35	110	20	50	365
2013	200	50	170	33	90	543
2014	260	75	230	48	140	753
2015	330	100	290	65	200	985
2016	410	125	350	84	240	1,209
2017	500	155	400	105	280	1,440
2018	600	185	440	129	310	1,664
2019	700	215	470	157	340	1,882
2020	800	240	490	190	360	2,080
2025	1,190	350	490	455	380	2,865
2030	1,340	410	490	1,370	390	4,000
2040	1,340	410	490	7,450	410	10,100
2050	1,340	410	490	18,700	430	21,370

Source: Ministry of Energy, Green Technology and Water, Industry Briefing on Feed-in Tariff Procedures, 29 July 2010. Available at <mbipv.net.my/Re%20Industry%20Briefing%20on%20FiT.PDF>.

8.3.3 Levelised Generation Costs

Table 8.8 compares the levelised generation costs for different technologies in the OECD and the SREP average price for generators under contract with TNB and the proposed FIT rates in Malaysia.

Table 8.8: Comparison of SREP and proposed feed-in tariff rates in Malysia with levelised generation costs in the OECD (EUR/MWh)

<table>
<tr><th>Technology</th><th>SREP[a]</th><th>Proposed FIT rate[a]</th><th>Levelised generation costs[b]</th></tr>
<tr><td>Solar PV[c]</td><td rowspan="3">48.09</td><td>254.19-341.21</td><td>143-408</td></tr>
<tr><td>Biogas</td><td>64.12-73.28</td><td>65</td></tr>
<tr><td>Biomass</td><td>61.83-70.99</td><td>60</td></tr>
</table>

Notes: [b]Figures based on a 5 per cent discount rate.
[c]Building-integrated solar PV using foreign-made components
Source: [a]See Incentive Opportunities Index above; [b]IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

[32] Chiang E. et al 2003 'Potential of Renewable Wave and Offshore Wind Energy Resources in Malaysia' Available at <eprints.usm.my/9180/1/Potential_of_Renewable_Wave_and_Offshore_Wind_Energy_Sources_in_Malaysia_(PPKMekanikal).pdf>.

8.3.4 Wind Power

8.3.4.1 Onshore Wind Power

Information on wind power development is scarce and wind does not feature heavily in Malaysia's renewable energy strategy due to poor potential. This notwithstanding, TNB commissioned a survey of wind resources in October 2009 from Argentinean renewable power developer Industrias Metalurgicas Pescarmona S. A (IMPSA), with a view to entering a partnership to develop Malaysia's first IPP wind farm. [33]

8.3.4.2 Offshore Wind Power

There are no commercially operating offshore wind farms in Malaysia as of September 2010.

8.3.5 Biomass

8.3.5.1 Solid Biomass

There is a considerable amount of biomass capacity spread across Malaysia; however, the majority of this capacity was accounted for by off-grid generation, mostly in the form of generators using palm-oil by-products as fuel.[34] At the end of 2008, 74 MW of solid biomass power was connected to the grid, all using palm oil by-products as a feedstock.[35]

Malaysia's palm oil industry is the most important source of potential for biomass generation, with an estimated 2,400 MW of untapped potential from empty fruit bunches (EFB), fibres and kernel shells as well as effluents from mills (see Table 8.9). Rice paddies, the next most important source, could contribute a theoretical 156 MW from straw and rice husks. Some potential exists from sugar mills and forestry waste, but most sugar mills in Indonesia are already producing energy, primarily heat, from their waste products and the use of wood waste residues in generation is declining because their recycling value is higher.[36]

Table 8.9: Palm oil production by-products and generating potential in Malaysia in 2006

Residue type	Amount (thousands of tonnes)	Generating potential (MW)
Empty fruit bunch (EFB)	15,701	714
Fibre	9,447	1,353
Kernel shells	4,211	683
Palm oil mill effluent (POME)	51,990	428
Total		3,178

Source: PTM, Malaysia Energy Centre; SIRIM, S*tandards and Industrial Research Institute of Malaysia*

The Malaysian palm oil industry, the Malaysian government, the UNDP and the Global Environment Facility (GEF) in 2002 launched the 'Biomass-based Power Generation and Cogeneration in the Malaysian Palm Oil Industry' (BioGen) programme to promote the use

[33] Harnessing the Power of the Wind, Malaysian Business, 16 October 2009. Available at <findarticles.com/p/articles/mi_qn6207/is_20091016/ai_n42132933/>.
[34] Malaysian Energy Centre, Fourth Asian Biomass Workshop, 2007. Available at <www.biomass-asia-workshop.jp/biomassws/04workshop/presentation_files/03_Anuar.pdf>.
[35] Suruhanjaya Tenaga, Statistics. Available at <www.st.gov.my>.
[36] UNDP, Biomass Power Generation and Co-generation in the Palm Oil Mills, Malaysia. Available at <www.undp.org.my/biomass-power-generation-and-co-generation-in-the-palm-oil-mills>.

of biomass. The BioGen programme offered investment support and assistance in applying for CDM credits to biomass developers. The programme will run until the end of 2010.[37]

Indicative capital expenditure for a typical solid biomass-fired power plant is quoted at 7 to 8 million MYR/MW (1.6 to 1.8 million EUR/MW). Operating expenditures would include the cost of purchasing biomass, (e.g. empty fruit bunch biomass) and 2009 prices were approximately 20 to 25 MYR/tonne (4.58 to 5.73 EUR/tonne) plus transportation costs. For EFB, the shredding and drying of the feedstock to meet boiler requirements of 35 per cent or less moisture content was approximately 2 to 3 MYR/tonne (0.46 to 0.69 EUR/tonne).[38]

Malaysia's Palm Oil Industrial Cluster (POIC) in Sabah state has plans to purchase palm-based biomass for power generation. POIC will receive financial assistance from the state government. POIC hopes to collect up to 6 million tonnes a year of palm waste.[39]

Whether policy initiatives and demonstration projects translate into increased adoption of biomass generation is an open question. The Minister for Energy and Green Technology stated in early 2010 that biomass was not a solution to growing power demand in Sabah, citing difficulties with obtaining a dependable supply of feedstocks, and the need to erect new transmission lines to feed power into the grid.[40]

8.3.5.2 Biogas

Rapid development and industrialisation coupled with lack of recycling facilities results in 19,100 tonnes of municipal waste disposed of every day in landfill sites in Malaysia.[41] There are 289 garbage disposal sites in the country, 113 of which are no longer operating, and waiting for decommissioning.[42] Much of this waste has a high organic component (as high as 72 per cent in some urban areas). This makes Malaysian landfill sites appropriate for power generation using landfill gas.[43] The first landfill gas power project in Malaysia was the 2-MW Jana project in Puchong, Kuala Lumpur. It was commissioned under the SREP in 2004.

In January 2008, waste water from palm oil production was used as a feedstock for biogas production. The biogas plant was used to provide power to a rubber factory.[44] The BioGen

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[37] UNDP, Biomass Power Generation and Co-generation in the Palm Oil Mills, Malaysia. Available at <www.undp.org.my/biomass-power-generation-and-co-generation-in-the-palm-oil-mills>.
[38] MBIPV, Strategic thrust of New RE Policy. Available at <www.mbipv.net.my/dload/NPVC%202009/Ir.%20Ahmad%20Hadri%20Haris.pdf>.
[39] Malaysia's state palm oil agency to buy biomass for power, REcharge News, 27 September 2010. Available at <www.rechargenews.com/energy/biofuels/article230308.ece>.
[40] Generating electricity from biomass not economical, Nam News Network, 15 March 2010. Available at <news.brunei.fm/2010/03/15/generatign-electricity-from-biomass-not-economical-says-malaysian-minister/>.
[41] Integrated Solid Waste Management, EU-Asia Presentation, August 2009. Available at <www.ea-swmc.org/download/euperak/Ms%20Puva.pdf>.
[42] SISA, Jabatan Sisa Pepejal. Available at <www.sisa.my/cmssite/content.php?cat=245&pageid=723&lang=bm>.
[43] UNITEN Landfill Gas Energy Centre (LFGEC) Press Release, February 2008. Available at <www.uniten.edu.my/newhome/content_list.asp?contentid=3345>.
[44] COGEN3, Biogas Plant for a Rubber Factory in Malaysia. Available at <www.cogen3.net/fsdp-rubbermalay.html>.

programme described above also provides support for biogas projects. The programme will run until the end of 2010.[45]

8.3.6 Solar Energy

8.3.6.1 Solar PV

Solar PV has been developing at a relatively fast pace, from practically no capacity in 2005 to 1,309 kW as of June 2010, almost all of which was off-grid.[46] Despite the abundant resource, solar PV applications in Malaysia are limited to mainly small-scale off-grid solar PV systems, especially for rural electrification.[47] The first installations were off-grid solar PV systems for 37 houses in Langkawi, followed by other projects in Tembeling (70 houses) and Pulau Sibu (50 houses). In the 1990s two rural electrification pilot projects, of 10 kW and 100 kW respectively, were implemented in Sabah with support from the New Energy and Industrial Technology Development Organization (NEDO) of Japan.[48]

Solar irradiation varies somewhat in Malaysia from the lowest levels in the Klang Valley (Kuala Lumpur) to Penang (Georgetown, northwest) and Kota Kinabalu (East Malaysia), where the highest levels are observed. Subject to location, a typical PV installation in Malaysia would produce approximately 900 to 1,400 kWh/kW.[49] Investment costs for a building-integrated solar PV system were approximately 19,120 MYR/kW (4,379 EUR/kW) in March 2010.[50]

International companies are interested in developing solar power in Malaysia. The German IBC Solar, which in September 2010 completed a 20-kW project supplying power to off-grid villages in Borneo, has called for more support for solar power in Malaysia, particularly as Malaysia is already one of the largest solar module producers in the world.[51] Another German company, Phoenix Solar, is planning on opening a Malaysian branch to take advantage of the proposed FIT system. Phoenix Solar's Singapore's branch has already completed a 169-kW system on the roof of a factory and a 71-kW system on the roof of a government building.[52]

8.3.6.2 Concentrated Solar-thermal Power

As of September 2010 there were no CSP projects in operation or in the planning stages in Malaysia.

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[45] UNDP, Biomass Power Generation and Co-generation in the Palm Oil Mills, Malaysia. Available at <www.undp.org.my/biomass-power-generation-and-co-generation-in-the-palm-oil-mills>.
[46] MBIPV, PV Installations. Available at <www.mbipv.net.my/content.asp?zoneid=4&categoryid=14>.
[47] Australian Business Council of Sustainable Energy, Renewable Energy in Asia: The Malaysia Report 2005.
[48] Speech of the Prime Minister. Available at <www.1malaysia.com.my/speeches/bandar-baru-bangi-selangor>.
[49] Australian Business Council of Sustainable Energy, Renewable Energy in Asia: The Malaysia Report 2005.
[50] MBIPV, Malaysia Average BIPV Price. Available at <www.mbipv.net.my/content.asp?higherID=0&zoneid=4&categoryid=12>.
[51] IBC Solar encourages Malaysia to support PV, PV Magazine, 21 September 2010. Available at <www.pv-magazine.com/news/details/beitrag/ibc-solar-encourages-malaysia-to-support-pv_100001231/>.
[52] Phoenix Solar forms Malaysian subsidiary to tap new feed-in tariff, RECharge News, 17 September 2010. Available at <www.rechargenews.com/energy/solar/article229713.ece>.

8.3.7 Small Hydro

Suitable run-of-the-river small hydro projects from 500 kW to 30 MW in capacity have been operating since the 1970s. At the end of 2009 there were 121.3 MW of off-grid mini-hydro power stations, the majority of them located in the Peninsular, as the rivers in Sarawak are deemed to be mainly suitable for large scale hydropower. Eighteen mini-hydroelectric projects totalling 69.9 MW have been approved under the SREP but not completed as of the end of 2009.[53]

8.3.8 Geothermal

There were no geothermal power plants in Malaysia as of September 2010. There are, however, possible sites for exploitation. There are 79 confirmed sites of geothermal activity, 61 of which are in the Peninsular, eight are in Sarawak and 10 in Sabah.[54] In 2009, the government's Mineral and Geosciences Department conducted a survey of the geothermal resources of Tawau in Sabah and said the resources were adequate to develop a 67-MW geothermal power plant in the area. The government allocated MYR 1.5 billion for the exploration and study of the region, and is planning on allocating more to develop the site in the future, although no time line was given.[55]

8.3.9 Marine (Wave/Tidal)

There were no marine energy projects under construction or in the planning stages in Malaysia as of September 2010. However, a survey of available marine resources in 2008 had identified suitable locations.[56]

[53] Australian Business Council of Sustainable Energy, Renewable Energy in Asia: The Malaysia Report 2005.
[54] World Wildlife Federation, Geothermal Ring of Fire, 2009. Available at <assets.panda.org/downloads/geothermal_ring_of_fire_b.pdf>.
[55] Mineral and Geosciences Department, Tawau Has Potential For Geothermal Power, July 2009. Available at <www.jmg.gov.my/en/press-releases/88-tawau-has-potential-for-geothermal-power.html>.
[56] Omar Yaakob et al. Prospects for Ocean Energy in Malaysia, 2006. Available at <dspace.uniten.edu.my/xmlui/bitstream/handle/123456789/543/Prospects for ocean energy in Malaysia.pdf?sequence=1>.

8.4 Political Will Risk Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Political Drivers</td><td>One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion.
If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.</td><td>0</td><td rowspan="5">0/5</td></tr>
<tr><td>Government Debt</td><td>One point if the government debt exceeds 60 per cent of the GDP.
A high debt ratio may lead to negative change in the incentive policy for renewable energy.</td><td>0</td></tr>
<tr><td>Political Change</td><td>One point if political change brought about by major opposition parties could negatively affect renewable electricity development.</td><td>0</td></tr>
<tr><td>Public Opposition</td><td>One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.</td><td>0</td></tr>
<tr><td>Nuclear Support</td><td>One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.</td><td>0</td></tr>
</table>

8.4.1 Government Structure

Malaysia is a parliamentary democracy with a constitutional monarch, Yang di-Pertuan Agong, as the head of state. Since independence in 1957, the dominant political party has been the Barisan Nasional (National Front, BN). Haji Mohd. Najib bin Tun Haji Abdul Razak has been the prime minister since April 2009. He has promoted ethnic harmony by dismantling many of the pro-Malay laws and he is in favour of increasing economic liberalisation. The new Ministry of Energy, Green Technology and Water was formed by the prime minister in 2009.

Major opposition parties are the Parti Keadilan Rakyat (PKR), the Democratic Action Party (DAP), and the Pan-Malaysian Islamic Party (PAS). In the recent general election of 2008, a majority was won by BN, but with a reduced share of the seats in parliament. The next election is due to be held in 2013.[57]

8.4.2 Government Debt

Public sector debt in Malaysia rose to 53.4 per cent of GDP in 2009, compared to 39.6 per cent in 2008. The central government's fiscal deficit also rose to 7.0 per cent in 2009 from 4.8 per cent in 2008.[58] However, only 7 per cent of Malaysia's debt is foreign currency denominated, while more than 90 per cent of the local currency debt is held by domestic financial institutions.[59]

The government has set a deficit target of 5.5 per cent in 2010, which the IMF believes can be met due to better-than-expected economic growth in 2010, partially due to higher revenues

[57] Export Development Canada, Malaysia, February 2010. Available at <www.edc.ca/english/index.htm>.
[58] World Bank, Asia Update 2010. Available at <go.worldbank.org/T8NWNE94P0>.
[59] Central Bank, Published Numbers. Available at <www.bnm.gov.my/index.php?ch=111>.

from the oil and gas sector. Malaysia is also considered the second most open country to foreign investment in the ASEAN, after Singapore.[60]

8.4.3 Targets and Commitments

Malaysia is a signatory to the Kyoto Protocol; however, it is not an Annex 1 country and hence does not have specific GHG emissions reduction targets specified in the agreement. In the 2009 Copenhagen Climate Change Summit, the prime minister offered 'credible' carbon cuts as long as funding and technological knowledge are offered by the developed nations on the same international stage, and he put forward the possibility of introducing a voluntary target of a 40 per cent reduction in the carbon intensity of the economy by 2020, compared to 2005 levels.[61] However, as of September 2010, Malaysia had not formally agreed to a emissions reduction target under the Copenhagen Accord.[62]

Malaysia does not have a general renewable energy target, but has introduced a renewable power goal of 985 MW installed by 2015. This target is broken down into 330 MW of biomass, 100 MW of biogas, 290 MW of mini hydro, 65 MW of solar PV and 200 MW of solid waste. It is envisioned that 5.5 per cent of total electricity generation will come from renewable energy sources (see Table 8.10).

Table 8.10: Malaysian government commitments

GHG emissions	None
Renewable energy (RE)	None
Renewable electricity	Government goal for renewable power to total 985 MW by 2015 (330 MW of biomass, 100 MW of biogas, 290 MW of mini hydro, 65 MW of solar PV and 200 MW of solid waste)

Source: Government of Malaysia, Tenth Malaysian Plan, Chapter 6. Available at <www.epu.gov.my/html/themes/epu/html/RMKE10/img/pdf/en/chapt6.pdf>.

8.4.4 Public Sentiment

There has not been a public survey conducted with specific regards to public sentiment towards renewable energy, but polls have revealed public opinion to be largely sympathetic towards the idea of giving up subsidies for fossil fuels. In 2009, one poll showed that 61 per cent of respondents in Malaysia said that there should be a reduction in subsidies to curb the fiscal deficit.[63]

[60] IMF, Malaysia: Staff Report for the 2010 Article IV Consultation, July 2010. Available at <www.imf.org/external/pubs/ft/scr/2010/cr10265.pdf>.
[61] Interview: Malaysian PM to Offer CO2 Reductions, Reuters, 13 December 2009. Available at <in.reuters.com/article/idINIndia-44679920091213>.
[62] See the UNFCCC's website at <www.unfccc.int>.
[63] Government of Malaysia, Tenth Malaysian Plan, Chapter 6. Available at <www.epu.gov.my/html/themes/epu/html/RMKE10/img/pdf/en/chapt6.pdf>.

8.5 Grid Connection Risk Index

Measure		Value	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	**4/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	2	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

8.5.1 Functional Separation

There are three main vertically integrated government-owned regional utilities in Malaysia, Tenaga Nasional Berhad (TNB), located on the Peninsular Malaysia; Sabah Electricity Sdn. Bhd (SESB), located in the state of Sabah; and Syarikat SESCO Berhad (previously Sarawak Electricity Supply Corporation), located in the state of Sarawak. TNB is a private company that is wholly owned by the government; SESB is 80 per cent owned by TNB and 20 per cent owned by the state government of Sabah; and SESCO is wholly owned by Sarawak Energy Berhad, which is 65 per cent owned by the state government of Sarawak. All three regional utilities are the sole purchasers of all generation. The government continues to exert considerable influence on the business activities of all three utility companies.[64]

The Malaysian government has rarely intervened to unilaterally change the contracts of IPPs during times of fiscal stress, unlike other countries such as Indonesia, and the major utilities enjoy high levels of confidence among the IPP investors owing to the extremely high rates of return which some IPP projects have earned, estimated by analysts as being in the range of 18 to 25 per cent for the first wave of IPPs following the part-privatization of TNB in 1992.[65]

Electricity tariffs for consumers are heavily subsidised by the government. However, in the Tenth Malaysian Plan (2011-2015), the government has indicated that it will promote the transition to market-based rates and reduce or remove the subsidy.[66]

8.5.2 Grid Capacity

The quality of transmission systems in Peninsular Malaysia, Sabah, and Sarawak is adequate to cope with new generating capacity due to transmission and distribution grid upgrades

[64] Jalal T, National Energy Policies and the Elctricity Sector in Malaysia, 2009. Available at <ir.canterbury.ac.nz/bitstream/10092/4162/1/12621660_C81.pdf>.
[65] Risen Jayaseelan, Current Affairs, Malaysian Business, 16 December 1999, p. 17. Available at <iis-db.stanford.edu/pubs/20956/Malaysia_IPP.pdf>.
[66] Government of Malaysia, Tenth Malaysian Plan, Chapter 6. Available at <www.epu.gov.my/html/themes/epu/html/RMKE10/img/pdf/en/chapt6.pdf>.

undertaken since 2000.[67] The government is planning on investing more into both the transmission and distribution grids under the Tenth Malaysian Plan (2011 to 2015). New transmission projects that will be implemented include overhead lines from Bentong South to Kampung Pandan via Ampang East in Peninsular Malaysia, from the Bakun Hydroelectric Project to Similajau in Sarawak and other transmission projects in Sabah.[68]

One of the main problems with the Malaysian energy strategy has been the lack of interconnectors between the three grids which operate on the Peninsular, Sabah and Sarawak. A planned 650 km submarine cable between Sarawak and the Peninsular, originally proposed as a result of the 2,400-MW Bakun hydropower plant, has been approved by the government but construction has not started as of August 2010 and it was uncertain if the cable would be completed.[69]

Rural electrification programs, especially in Sabah and Sarawak, will continue to add stand-alone system generators using solar PV, mini-hydro, and hybrid biomass-fossil fuel systems as well as to upgrade local grids. The government has pledged MYR 5.4 billion (EUR 1.2 billion) towards upgrading the infrastructure in Sarawak state, where many remote areas remain off-grid, and a part of this money is earmarked for improving rural electrification.[70]

8.5.3 Access and Connection Cost

Renewable power developers are required to bear all the costs of utility system reinforcements and grid connection works to the main networks. The renewable power plant has to be located within a 10 km radius of the nearest public utility interconnection point, with the exception of mini-hydro generators, and all connection facilities are to be handed over to the grid operator (in most cases the public utility TNB).[71] The distance of power plant to grid connection point is a major factor in determining the interconnection cost. For 11 kV systems (up to approximately 5 MW) the cost is approximately MYR 250,000 per km (EUR 57,000 per km). The procurement and installation of insulated, aerial bunched cables (ABC) for 33kV systems (up to approximately 12 MW) would incur up to 50 per cent more in capital costs.[72]

As of August 2010, renewable power does not receive priority in terms of grid connection or use of the grid.[73] However, under the proposed FIT system, renewable power plants will receive obligatory connection to the grid, and all their output will need to be purchased by the regional grid operator (obligatory offtake).[74]

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[67] Malaysia District Export Council. Available at <www.malaysiamission.com/team.php?id=32>.
[68] Government of Malaysia, Tenth Malaysian Plan, Chapter 6. Available at <www.epu.gov.my/html/themes/epu/html/RMKE10/img/pdf/en/chapt6.pdf>.
[69] Malaysia Development Awaits Clarification on Bakun Power Supply, Star, 19 July 2010. Available at <biz.thestar.com.my/news/story.asp?file=/2010/7/19/business/6684473&sec=business>.
[70] RM 5.4 billion for rural electrification project, Borneo Post, 9 March 2010. Available at <www.theborneopost.com/?p=15585>.
[71] Suruhanjaya Tenaga, SREP. Available at <www.st.gov.my/index.php?option=com_content&view=article&id=5245&Itemid=4228&lang=en>.
[72] Information from the National MBIPV Project, available at <www.mbipv.net.my>.
[73] The Need to Switch to Renewable Energy, Star, 17 April 2010. Available at <biz.thestar.com.my/news/story.asp?file=/2010/4/17/business/6064381&sec=business>.
[74] Ministry of Energy, Green Technology and Water, Industry Briefing on Feed-in Tariff Procedures, 29 July 2010. Available at <mbipv.net.my/Re%20Industry%20Briefing%20on%20FiT.PDF>.

8.6 Planning Permission Risk Index

Measure		Value	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**1/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

8.6.1 Complexity and Expected Timescales

Renewable electricity developers require approval and a license from the Energy Commission prior to obtaining connection to the network. Applications are accepted on a rolling basis throughout the year and obtaining a license usually takes less than three months if all the technical conditions have been satisfied.

Delays are a common problem when dealing with grant funding agencies and public utilities. For instance, the Green Technology Financing Scheme has struggled to deliver funding since its inception in 2010, only managing to process 19 out of 200 applications received in the first three months of operation.[75] Smaller developers are at a disadvantage when competing with the large utilities, whose political connections and monopoly status give them substantial leverage. For example, it took approximately two years for a power purchasing agreement for the Sunquest biomass project to be concluded with with TNB after obtaining SREP approval.[76]

8.6.2 Local Opposition and Procedural Improvements

Subsidised energy prices and large fossil fuel reserves have resulted in very few commercial projects. There has been no local opposition, however, with past renewable energy initiatives.

[75]Palm Oil Analysis 2010. Available at <mypalmoil.blogspot.com/2010/04/renewable-energy-feed-in-tariffs-bill.html>.
[76] EcoSecurities, Request for Review for: “Sunquest Biomass Renewable Energy Project” (2928): Response from the Project Participants (Letter to the UNFCCC from developer). Available at <cdm.unfccc.int/UserManagement/FileStorage/K3L2I01AYE4WZ8DJPFQXT95ORG7UBV>.

8.7 Conclusion

Although there is sufficient generating capacity to meet projected peak demand in the short term, continued economic and population growth is likely to necessitate the installation of further capacity by 2020. Malaysia is rapidly depleting its reserves of fossil fuels but it is fortunate to have an abundance of renewable resources.

While solar and geothermal power have huge potential, the availability of cheap biomass to sustain large-scale power plants is questionable, given the competing uses for many existing materials. Over 70 per cent of hydropower potential is located in the sparsely populated region of Sarawak, requiring costly interconnection work if hydropower is to play a major part of Malaysia's energy mix. Also, wind speeds are relatively low throughout the country, making large-scale onshore wind power development unlikely in the near term.

Developers have also complained about the lack of favourable financing schemes and the uncertain financial viability of renewable power projects. The keenly awaited Renewable Energy Act, expected to be enacted in 2011, will introduce a FIT regime which should help developers access credit and financing—and thereby promote development. These changes will also be occurring against the backdrop of decreasing fossil fuel subsidies and a strengthening of the rights of renewable power developers, providing yet another boost to renewable development. However, until the new FIT system is in place and functioning, it is difficult to know what the barriers to development will be in the future.

Chapter 9: The Philippines

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
A feed-in tariff and a tradable green certificate system have been authorised by the government, but are not expected to be in place until 2011.	**0/5**

2. Power Market Opportunities Index	Value
Rising demand is already causing power shortages in some areas creating a need for new generation. Energy import dependency is increasing.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind, Geothermal
Emerging Technologies Technologies that have growth potential in the country.	Solar PV, Marine energy

Risk Indices

4. Political Will Risk Index	Value
The public is generally unwilling to pay more for renewable energy and if electricity prices increase, the level of unwillingness to pay could increase as well.	**1/5**

5. Grid Connection Risk Index	Value
Grid connection fees are high and grid capacity expansion is needed. The transmission system operator is, however, working on enhancing the power grid.	**2/5**

6. Planning Permission Risk Index	Value
Overly complex planning guidelines and a large number of authorities that need to be consulted are identified as hindering development. The government, however, intends to reduce all barriers to development by, for example, addressing planning concerns.	**2/5**

9.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.*	0	**0/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	0	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.*	0	

9.1.1 Operating Incentives

The framework legislation for the Philippine's renewable electricity strategy is the Renewable Energy Act of 2008, which took effect on 30 January 2009.[1] It constitutes a combination of mechanisms intended to encourage renewable power generation for both grid-connected and off-grid generators. The most important element of the legislation is the government's commitment to a feed-in tariff (FIT) system, although its decision to mandate a minimum percentage of generation from renewable sources and to create a market for trading certificates are also significant.

9.1.1.1 Proposed Feed-in Tariff

The energy regulator, the Energy Regulatory Commission (ERC), issued the guidelines surrounding the proposed feed-in tariff (FIT) system in July 2010. Under the guidelines, wind, solar, run-of-the-river hydro, and marine power, as well as biomass and biogas combined heat and power (CHP) plants will be eligible to receive 20-year set rates. Time of day adjustments will be made for generation that is dispatchable (for example, hydropower and biomass). The National Grid Corporation of the Philippines (NGCP), the transmission systems operator (TSO), will purchase all output and will be reimbursed for the purchases through a special surcharge on electricity bills.

The National Renewable Energy Board (NREB) will propose FIT rates and the annual capacity cap for each technology. The annual capacity cap will be based upon the requirements of the Renewable Portfolio Standard (see below).[2] The NREB is expected to propose the FIT rates in November 2010, with the ERC making a final decision on whether to

[1] DOE, Rules and Regulations Implementing 2008 Renewable Energy Act, May 2009. Available at <www.doe.gov.ph/popup/DC2009-05-0008.pdf>.
[2] ERC, Resolution No. 16. Series of 2010- Resolution Adopting the Feed In Tariff Rules (7/23/2010). Available at <www.erc.gov.ph/cgi-bin/issuances/files/Resolution no. 16 series of 2010_final.pdf>.

approve the rates in early 2011.[3] Preliminary information shows that rates will be between 7,000 PHP/MWh to 25,000 PHP/MWh (115 EUR/MWh to 413 EUR/MWh[4]), with solar PV receiving the higher rate.[5]

9.1.1.2 Renewable Portfolio Standard

The 2008 Renewable Energy Act also introduced the Renewable Portfolio Standard (RPS), a tradable green certificate (TGC) system. The RPS will oblige all electricity suppliers to source a set percentage of their electricity from renewable energy sources. There will be separate quotas for each of the three grid zones, Luzon, Visayas and Mindanao, and the quota will rise by a minimum of 1 per cent a year. More details are expected at the end of 2010 or early 2011. Suppliers will be able to sign bilateral contracts with renewable power generators or purchase certificates separately to meet their quota. Certificates will be traded on the Wholesale Electricity Spot Market, the government-licensed power exchange.[6]

9.1.2 Investment Support

Under the Renewable Energy Act of 2008, the Philippine government offers financial assistance for investment in renewable power.

New and existing renewable energy developers will enjoy an income tax holiday for seven years from the start of commercial operations, provided they are investing large sums of capital, using innovative technology, providing significant employment or basing their installation in a less developed area, as defined by the National Renewable Energy Board (NREB). Once this period has elapsed, there will be a preferential corporate income tax rate of 10 per cent (normal corporate tax is 30 per cent) on net income after the lapse of the income tax holiday period. Renewable energy developers already in commercial operation for more than seven years are also eligible for the preferential corporate tax rate.[7]

Accelerated depreciation is available for renewable energy installations which fail to qualify for the income tax holiday incentive. The accelerated rate permitted is up to twice the rate that which would have been used according to the rules and regulations of the National Internal Revenue Code of 1997.[8]

All equipment and machinery relating to the exploitation of renewable energy is deemed by the Renewable Energy Act to be exempt from Philippine import duties and VAT. For purchases of renewable-energy related machinery, materials and parts in the Philippines, a tax

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[3] James A. Loyola, ERC to Issue RE Tariff Guidelines Next Year, Manila Bulletin, 17 September 2010. Available at <www.mb.com.ph/articles/277645/erc-issue-re-tariff-guidelines-next-year>.
[4] An exchange rate of EUR 1 = PHP 0.01653 is used in this report (based on average exchange rate in the first six months of 2010.
[5] Honey Garcia, Philippines unveils feed-in tariff rules for renewable energy, Ecoseed, 27 July 2010. Available at < www.ecoseed.org/en/politics/feed-in-tariff/article/32-feed-in-tariff/7674-philippines-unveils-feed-in-tariff-rules-for-renewable-energy>.
[6] DOE, Rules and Regulations Implementing 2008 Renewable Energy Act, May 2009. Available at <www.doe.gov.ph/popup/DC2009-05-0008.pdf>.
[7] DOE, Rules and Regulations Implementing 2008 Renewable Energy Act, May 2009. Available at <www.doe.gov.ph/popup/DC2009-05-0008.pdf>.
[8] The 2008 Renewable Energy Act, p 14. Available at <www.senate.gov.ph/lis/bill_res.aspx?congress=14&q=SBN-2046>.

credit equivalent to 100 per cent of the import duties and VAT that would have been incurred if these goods were imported is available.[9]

Annual realty tax payments on land, equipment and machinery used for facilities generating renewable electricity are limited to a maximum of 2.5 per cent of the cost of the investment.[10] Electricity generated from renewable sources is exempt from the payment of the electricity consumption charge.[11] The proceeds from the sales of carbon emission credits are also exempt from taxes.[12]

The Renewable Energy Act 2008 created a Renewable Energy Trust Fund (RETF) to help finance the research, development, demonstration, and promotion of renewable energy systems by offering grants, loans, equity investments, insurance and guarantees. Funding for the RETF will come from fines imposed under the Renewable Energy Act 2008, government revenues, and donations. The Act also stipulates that government financial institutions, such as the Development Bank of the Philippines, Land Bank of the Philippines, and Phil-Exim Bank, need to provide preferential loans to renewable energy projects authorised by the Department of Energy [13]

9.2 Power Market Opportunities Index

Measure		**Value**	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	2	**4/5**
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

9.2.1 Energy Consumption

In 2008, primary energy supply totalled 39.5 million tonnes of oil equivalent (Mtoe). Oil was the largest source of primary energy in 2008, followed by geothermal energy (see Figure 9.1).

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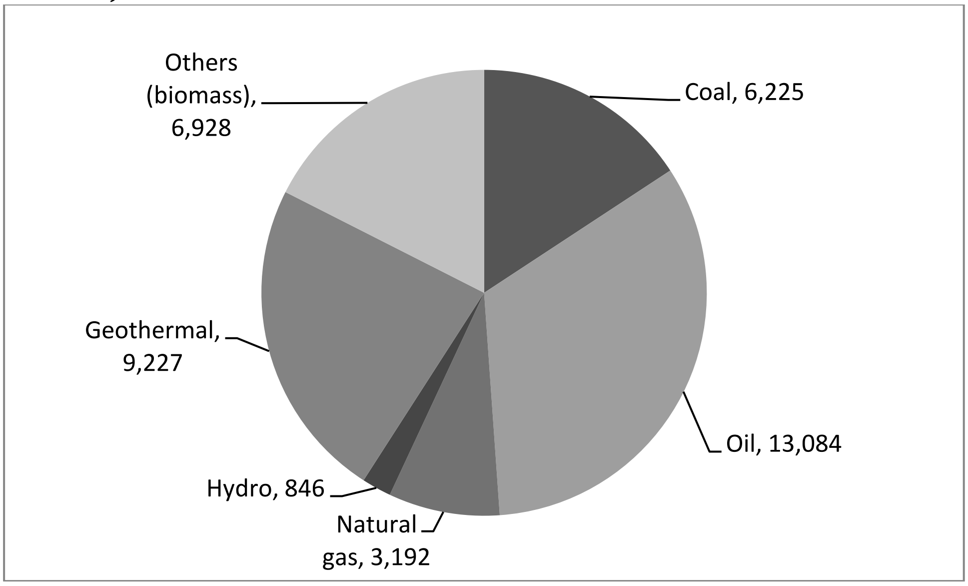
[9] Vincent S. Pérez, Status of Renewable Energy Policy in the Philippines, 2009. Available at <www.adb.org/documents/events/2009/CCEWeek/Presentation-Vincent-Perez-Energy-PHI.pdf>.
[10] The 2008 Renewable Energy Act, p 13. Available at <www.senate.gov.ph/lis/bill_res.aspx?congress=14&q=SBN-2046>.
[11] The 2008 Renewable Energy Act, p 13. Available at <www.senate.gov.ph/lis/bill_res.aspx?congress=14&q=SBN-2046>.
[12] Limbo, Genevieve. Tax in the Philippines, 19 October 2009. Available at <www.pwc.com/ph/en/taxwise-or-otherwise/18-jun-2009.jhtml>.
[13] The 2008 Renewable Energy Act. Available at <www.senate.gov.ph/lis/bill_res.aspx?congress=14&q=SBN-2046>.

Primary energy supply in the Philippines only increased at a compound annual growth rate (CAGR) of 0.34 per cent between 1999 and 2008. In that time period, the consumption of natural gas and coal increased, while oil consumption declined, mostly due to the replacement of oil-fired power generation with gas and coal alternatives. The consumption of geothermal and hydro remained relatively stable. Just over 50 per cent of energy sources were imported, including virtually all of the oil consumed in the country.[14] Primary energy consumption is projected to grow at an annual rate of 3.7 per cent between 2008 and 2030.[15]

Total final energy consumption was 23.4 Mtoe in 2008. From a high of 25.4 Mtoe in 1997, final energy consumption remained between 23 and 24 Mtoe between 2000 and 2008.[16]

Figure 9.1: Primary energy consumption by source in the Philippines in 2008 (ktoe): Total 39,503 ktoe



Source: APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.

9.2.2 Electricity Sector

There are three regional grid systems in the Philippines, centred among the three island groups of Luzon, Visayas, and Mindanao. There is limited interconnection between the grids and each grid system meets demand independently. The Luzon grid system, which includes the national capital Manila, is the most populous region, and has a peak demand five times larger than the other grid systems. In 2009, peak demand nationally reached 9,122 MW, a 0.8 per cent increase from 2008. Peak demand on the Luzon grid accounted for 6,928 MW of national peak demand (see Table 9.1).

The time of peak demand varies between the grid zones. In Luzon, peak demand occurs mid-year when the temperature is at its highest, which in 2009 occurred in May. In Mindanao, peak demand historically occurs in November or December and is driven by industrial demand. In Visayas, peak demand occurs later, usually in September.[17]

[14] APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.
[15] Department of Energy, Philippines Energy Outlook 2009-2030. Available at <www.doe.gov.ph/PEP/Philippine Energy Outlook.pdf>.
[16] APEC Energy Database. Available at <www.ieej.or.jp/egeda/database/database-top.html>.
[17] Department of Energy, Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>.

Total electricity consumption had a slight increase of 3.4 per cent from 49,206 GWh in 2008 to 50,868 GWh in 2009. Just over two-thirds of consumption, or 33,853 GWh, were supplied by independent power producers (IPPs). Growth in electricity consumption in 2009 was mainly driven by the commercial and residential sectors. The commercial sector overall consumed 4.9 per cent more electricity in 2009 than in 2008, and growth was even higher in Mindanao, where the year-on-year growth rate was 11.36 per cent. Growth in electricity demand for residential purposes was more uniform across the grids, with aggregate growth of 5.2 per cent between 2008 and 2009.[18]

Table 9.1: Peak annual demand in the regional grid systems in the Philippines from 2000 to 2008

Year	Luzon		Visayas		Mindanao		Total	
	Demand (MW)	Change from previous year (%)	Demand (MW)	Change from previous year (%)	Demand (MW)	Change from previous year (%)	Demand (MW)	Change from previous year (%)
2000	5,450	9.3	749	2.7	939	5.3	7,138	8.0
2001	5,646	3.6	898	19.9	953	1.5	7,497	5.0
2002	5,823	3.1	903	0.6	995	4.4	7,721	3.0
2003	6,149	5.6	995	10.2	1,131	13.7	8,275	7.2
2004	6,323	2.8	1,025	3.0	1,177	4.1	8,525	3.0
2005	6,443	1.9	1,037	1.2	1,149	-2.4	8,629	1.2
2006	6,466	0.4	1,066	2.8	1,228	6.9	8,760	1.5
2007	6,643	2.7	1,102	3.4	1,241	1.1	8,987	2.6
2008	6,674	0.5	1,176	6.7	1,204	-3.0	9,054	0.7
2009	6,928	3.8	1,241.0	5.5	1,303.0	8.2	9,122	0.8

Source: Department of Energy, Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>.

The total installed generating capacity in the Philippines was 15,610 MW in 2009, down slightly by 71 MW from 2008. Luzon, the largest island grid, hosts approximately 11,864 MW of the total installed capacity. Conventional fossil fuel-fired power plants, largely located in the Luzon grid, remain the dominant type of generator—collectively accounting for 65 per cent of installed capacity. Within this category, coal power was the dominant generating source, contributing 27 per cent of the total, followed by oil and natural gas plants (see Figure 9.2).

Between 1999 and 2009, total installed generating capacity increased at a CAGR of 2.3 per cent. Coal and natural gas generating capacity have seen the largest increase in generating capacity in the same period, with CAGRs of 2.5 per cent and 98.4 per cent respectively, while oil-fired capacity has seen a negative CAGR of -4 per cent.

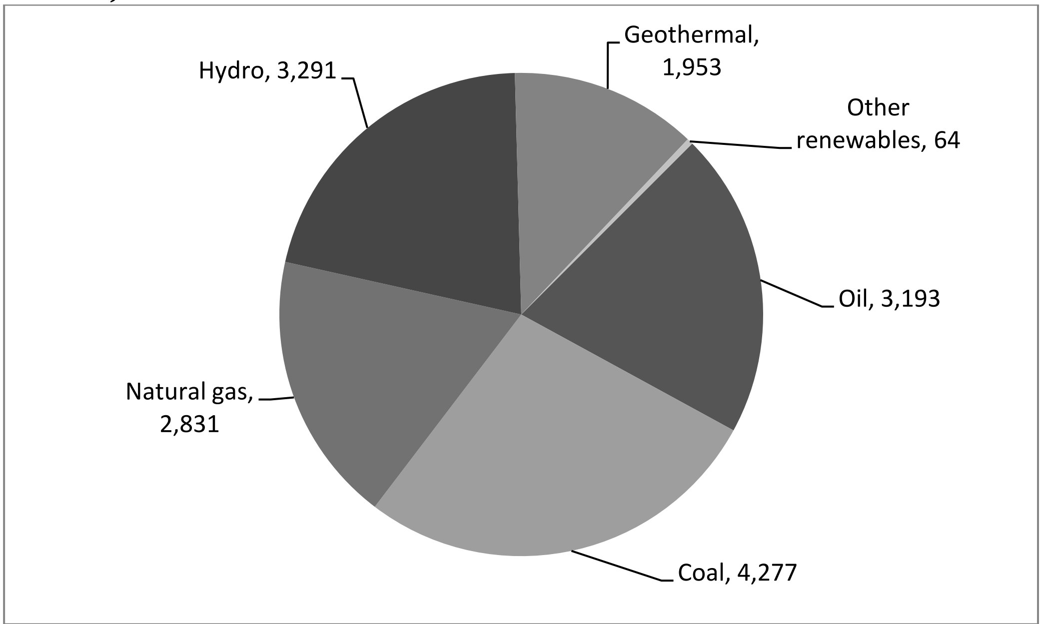
Renewable energy sources were also an important source of generating capacity in 2009. The most important contributors were hydropower and geothermal plants, which accounted for 21 and 12.5 per cent of the total, respectively. Other renewable sources such as solar, wind and biomass, were minor contributors, making up only 0.41 per cent of the total.

Gross power generation in 2009 reached 61,933 GWh (see Figure 9.3), 1.8 per cent higher than 2008. Fossil fuel generation increased by 3.9 per cent, from 40,193 GWh in 2008 to

[18] Department of Energy, Power Situationer 2009. Available at <www.doe.gov.ph/EP/Powersituationer.htm>.

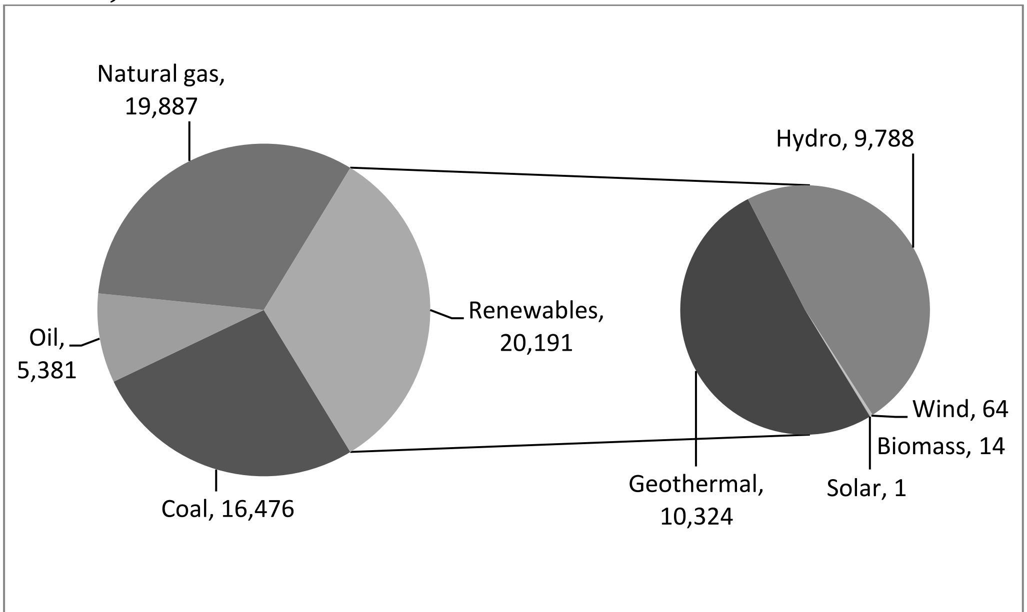
41,744 GWh in 2009. Generation from renewable energy sources actually fell by 2.1 per cent between 2008 and 2009. The decline in renewable generation is primarily due to the 3.7 per cent fall in geothermal generation which occurred due to a combination of outages and shutdowns—which were undertaken mainly to perform scheduled repairs on geothermal plants, for example, the 150-MW Bacman plant has been closed since May 2009 because of repairs.[19]

Figure 9.2: Total installed generating capacity in the Philippines in 2009 (MW): Total 15,610 MW



Source: Department of Energy, Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>.

Figure 9.3: Electricity generation mix in the Philippines in 2009 (GWh): Total 61,933 GWh



Source: Department of Energy, Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>.

[19] Department of Energy, Power Situationer 2009. Available at <www.doe.gov.ph/EP/Powersituationer.htm>.

The Philippine Energy Plan 2009-2030 has a stated aim of pursuing self-sufficiency and energy diversification. Nonetheless, the pipeline of capacity due to be added to the Philippine power system between 2010 and 2014 (see Table 9.2) is dominated by coal, which makes up 89.9 per cent of the total capacity that will be added in this period. The remaining 10.1 per cent will be a combination of geothermal, biomass, and hydro projects, which will add 70 MW, 17.5 MW, and 50.5 MW to the grid, respectively.

Table 9.2: Committed new capacity additions in the Philippines between 2010 and 2014 (MW)

Region	Coal		Biomass		Hydro		Geothermal		Total
	MW	No. of projects	MW	No. of projects	MW	No. of projects	MW	No. of projects	MW
Luzon	600	1	0	0	0	0	0	0	600
Visayas	616	4	17.5	1	0	0	20	1	653.5
Mindanao	0	0	0		50.5	2	50	1	100.5
TOTAL	1,216	5	17.5	1	50.5	2	70	2	1,354

Source: DOE, Energy Plan 2009-2030, May 2010. Available at <www.philippinechamber.com/index.php?option=com_content&view=article&id=846:doe-presents-philippine-energy-plan&catid=31:energy&Itemid=78>.

For the period 2010 to 2020 there are also a number of projects which are due for completion in the period, but which are lacking funding or planning permission (see Table 9.3). To meet projected demand, however, more additional capacity will be required. In particular, the dependable capacity (in other words, dispatchable capacity that is able to meet peak demand) in the Visayas and Mindanao grids is not adequate to maintain a 25 per cent reserve margin above the level of peak demand. In early 2010 drought conditions forced rationing and rolling brownouts due to a supply deficit in March of 163 MW[20] in Visayas and 632 MW in Mindanao.[21] To meet projected demand, an additional 16,550 MW will be needed above the committed capacity additions (see Table 9.4) by 2030, based on the government's reference 'business-as-usual' scenario, that is, more than double the total installed capacity in 2009.

Table 9.3: Planned new capacity additions in the Philippines between 2010 and 2020

Region	Coal	Gas	Biomass	Hydro	Wind	Geothermal	Total
Luzon	620	300	70	175	246	120	1,531
Visayas	100	0	35.5	49	0	40	224.5
Mindanao	220	0	35	335.3	5	0	595.3
TOTAL	940	300	140.5	559.3	251	160	2,350.8

Source: DOE, Energy Plan 2009-2030, May 2010. Available at <www.philippinechamber.com/index.php?option=com_content&view=article&id=846:doe-presents-philippine-energy-plan&catid=31:energy&Itemid=78>.

[20] NGCP, March 2010 Grid Report. Available at <www.ngcp.ph/frame.asp?doc=news_file/Power Update March 15 PM.pdf>.
[21] Amy R. Remo, Power shortage in Mindanao get worse; rationing eyed, Philippine Daily Inquirer, 23 February 2010. Available at <newsinfo.inquirer.net/breakingnews/regions/view/20100223-254931/Power-shortage-in-Mindanao-get-worse-rationing-eyed>.

Table 9.4: Power supply and demand outlook in the Philippines from 2009 to 2030

Grid	Dependable Capacity (2009)	Peak demand (2009)	Committed capacity 2010-2014	Required additional capacity 2010-2030
Luzon	10,231	6,928	600	11,900
Visayas	1,393	1,241	653.5	2,150
Mindanao	1,696	1,303	100.5	2,500
Total	13,320	9,054	1354	16,550

Source: DOE, Energy Plan 2009-2030, May 2010. Available at <www.philippinechamber.com/index.php?option=com_content&view=article&id=846:doe-presents-philippine-energy-plan&catid=31:energy&Itemid=78>.

9.2.3 Nuclear Power

There is one nuclear power plant in the Philippines, the 620-MW Bataan Nuclear Power Plant (BNPP), 130-km west of Manila, completed in 1984. It has, however, never been used to generate power. Construction on the two reactors started in 1976 under the Marcos regime; however, the post-Marcos government cancelled the project over safety concerns in 1984 after only one reactor had been completed (although the project was already five-times over its budget). It was only in 2007 that the debts for the construction of the plant were finally paid.

In 2008, National Power Corporation (Napocor), the state-owned power utility in the Philippines, and the largest generator in the country, signed an agreement with Korea Electric Power Corporation to look into the potential of making the plant operational.[22] Toshiba Power has also expressed its interest in rehabilitating the Bataan plant or in building new plants.[23] The government has indicated that it is against companies undertaking work on the Bataan plant, but it is interested in the possibility of constructing new nuclear plants due to the projected increase in electricity demand. General feasibility studies are expected to be completed by the government in late 2010.[24]

9.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Onshore wind
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV, Marine energy

[22] Alastari Macindoe, Philippines's Power Dilemma, Strait Times, February 2009. Available at <blogs.straitstimes.com/2009/2/6/philippines-power-dilemma>.
[23] Euan Paulo C. Añonuevo Toshiba eyes Bataan nuclear power plant, Manila Times, 22 July 2010. Available at <www.manilatimes.net/index.php/top-stories/22056-toshiba-eyes-bataan-nuclear-power-plant>.
[24] Philippines Rejects Revival of Bataan Nuclear Power Plant, AHN, 28 July 2010. Available at <www.allheadlinenews.com/articles/7019415417>.

9.3.1 Renewable Electricity Generation

Generation of renewable power was 2.1 per cent lower in 2009 than in 2008 (see Table 9.5), which was mainly due to a 3.7 per cent contraction in geothermal generation which occurred due to the shutdown of several plants for maintenance work. Hydropower generation was also affected by hot weather and a comparative lack of rain in comparison to the previous year.

Geothermal and hydropower remain the primary renewable generating sources, with a 99.6 share in the generation mix in 2009. Next generation renewables such as wind in Luzon and biomass in Mindanao increased modestly, with 17 GWh added to the annual generation figures in 2009 relative to the previous year.[25]

In terms of installed capacity, the Philippine government hopes to achieve a target renewable capacity of 12,324.71 MW by 2020, a dramatic increase of over 100 per cent from its 2009 level of 5,313 MW (see Table 9.6).

Table 9.5: Renewable power generation in the Philippines from 2005 to 2009 (MWh)

Technology	2005	2006	2007	2008	2009	CAGR 2005-2009 (%)
Geothermal	9,902,443	10,465,279	10,214,688	10,722,780	10,323,847	1.1
Hydro	8,386,773	9,939,413	8,563,433	9,842,534	9,787,567	3.9
Wind	17,469	5,3235	57,842	61,386	64,428	38.6
Solar	1,517	1,376	1,309	1,304	1,252	-4.7
Biomass	N/A	N/A	N/A	N/A	13,710	N/A
Total	18,308,202	20,459,303	18,837,272	20,628,004	20,190,804	2.5

Source: Department of Energy, Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>.

Table 9.6: Installed generating capacity of renewable power in the Philippines in 2009 and targets to 2030

Technology	2009[a]	Target[b]					CAGR required 2009-2030 (%)
		2010	2015	2020	2025	2030	
Geothermal	1,953	1,972.07	2,382.07	3,037.07	3,177.07	3,447.07	2.8
Wind	33	33	199	903	953	1,018	17.7
Solar	6	6.74	11.75	36.27	60.65	85.00	13.5
Biomass	30	75.50	93.90	240.8[c]	240.8[c]	240.8[c]	10.4
Hydro	3,291	3,477.81	4,433.51	6,432.21	6,615.19	7,533.84	4.0
Total	5,313.00	5,565.12	7,120.23	10,649.35	11,046.71	12,324.71	4.1

Notes: There is no year set when the target capacity for biomass will be reached.
Sources: [a]Department of Energy, Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>; [b]Department of Energy, Philippine Energy Plan 2009-2030. Available at <www.doe.gov.ph/PEP/PEP%202009-2030.pdf>.

9.3.2 Resource Potential

A resource assessment of solar power potential showed that the country has an annual potential average of 5.1 kWh/m^2 per day.[26]

[25] Department of Energy, Power Situationer 2009. Available at <www.doe.gov.ph/EP/Powersituationer.htm>.
[26] DOE, Biomass, Solar, Wind and Ocean. Available at <www.doe.gov.ph/ER/BioOSW.htm>.

The Philippines has the largest wind power potential in Southeast Asia, amounting to 7,404 MW,[27] the majority of which is located in the Visayas and Luzon regions.[28] The fact that the Philippines lies on the fringes of the Asia-Pacific monsoon belt contributes to this potential. Data from the Philippine Geophysical Astronomical Services Administration (PAG-ASA) shows that the country has a mean average of about 31 W/m^2 of wind power density. In addition, a study conducted by the US-NREL in 1999 estimated that over 10,000 km^2 of land have good-to-excellent wind resource potential. Using conservative assumptions of about 7 MW per km^2, these windy land areas could theoretically support approximately 70,000 MW of wind power.

Based on information from the Department of Agriculture (DA) and the Department of Environment and Natural Resources (DENR), the Philippines could generate a substantial volume of agricultural residues which could be used as feedstock for energy production. Latest estimates show that the country's agriculture sector could potentially produce 271.7 million barrels of fuel oil equivalent (MMBFOE) of biomass in 2003, increasing by 1.9 per cent annually.[29] By 2012, biomass supply potential is expected to reach 323.1 MMBFOE.[30] Distribution varies regionally, but overall there is the potential for an installed generating capacity of 445.67 MW from rice residue, 1,103.07 MW from coconut residue, and 703.23 from bagasse.[31]

The Philippines's hydro potential is estimated at 10,500 MW of which approximately 3,342 MW has been commercially developed. There is an additional 25.94 MW of small hydro that can be developed, primarily in Luzon.[32]

The Philippines is already the second largest producer of geothermal energy in the world, behind the USA, but there is still an estimated unexploited potential of another 2,600 MW, 1,200 MW of which is projected to be exploited by 2020.[33]

The country's ocean thermal resource area is 1,000 km^2, based on the archipelagic nature of the country. According to a recent study, the potential capacity for this resource is estimated to be 265 million megawatts.[34] Another study conducted by the Mindanao State University estimated that the potential theoretical capacity for wave energy is approximately 170,000 MW.[35] Initial ocean energy potential sites identified include the Hinatuan Passage,

[27] DOE, Wind Map. Available at <www.doe.gov.ph/ER/Maps%20-%20Wind.htm>.
[28] Vincent Perez, Status of Wind Power Development in the Philippines and Drafting of the Philippines' Wind Power Roadmap. Available at <www.adb.org/documents/events/2010/asia-clean-energy-forum/QLW-Philippines-Country-Presentation.pdf>.
[29] DOE, Biomass, Solar, Wind and Ocean. Available at <www.doe.gov.ph/ER/BioOSW.htm>.
[30] Vincent Perez, Status of Wind Power Development in the Philippines and Drafting of the Philippines' Wind Power Roadmap. Available at <www.adb.org/documents/events/2010/asia-clean-energy-forum/QLW-Philippines-Country-Presentation.pdf>.
[31] Information derived from DOE, Rice, Coconut and Bagasse Residue Maps. Available at <www.doe.gov.ph/ER/Maps%20-%20Rice%20Residues.htm> and <www.doe.gov.ph/ER/Maps%20-%20Coconut%20Residues.htm> and <www.doe.gov.ph/ER/Maps%20-%20Bagasse.htm>.
[32] DOE, Mico-hydro Map. Available at <www.doe.gov.ph/ER/Maps%20-%20Micro%20Hydro.htm>.
[33] DOE. Geothermal. Available at <www.doe.gov.ph/ER/geothermal.htm>.
[34] DOE, Ocean Thermal. Available at <www.doe.gov.ph/ER/Maps%20-%20Ocean%20Thermal.htm>.
[35] DOE, Wave Energy Map. Available at <www.doe.gov.ph/ER/Maps%20-%20Ocean%20Wave.htm>.

Camarines, Northeastern Samar, Surigao, Batan Island, Catanduanes, Tacloban, San Bernardino Strait, Babuyan Island, Ilocos Norte, Siargao Island and Davao Oriental.[36]

9.3.3 Levelised Generation Costs

There are no separate levelised generation costs for renewable power in the Philippines. As there are no operating incentives available for renewable power as of September 2010, it is not possible to compare levelised generation costs with incentives.

9.3.4 Wind Power

9.3.4.1 Onshore Wind Power

The Philippines remains the top wind producer in Southeast Asia with its 25-MW wind farm located in Bangui, Ilocos Norte. The recent addition of 8 MW commissioned in August 2008 brought the country's installed wind power capacity to 33 MW.[37]

In 2008, there were three pre-commercial contracts (PCCs) issued to Alternergy Philippine Holdings Corporation, which effectively granted construction permits to the company. In 2009, one PCC contract was converted to a renewable energy contract (120 MW in Burgos Ilocos Norte), which allows the developer to classify its output as renewable power; four additional RE contracts were then awarded (30 MW in Nabas, Aklan, 30 MW in Sual Pangasinan, 86 MW in Burgos, Ilocos Norte, and 50 MW in Pagudpud, Ilocos Norte); and there are 43 projects in the Luzon and Visayas regions where developers have signalled their interest.[38]

9.3.4.2 Offshore Wind Power

There are no offshore wind farms in the Philippines and there are no known plans to develop offshore wind farms.

9.3.5 Biomass

9.3.5.1 Solid Biomass

In the medium term, biomass energy will be primarily used for heating and cooking.[39] Biomass-fired power generation projects have been proposed, almost all combined heat and power. Projects located in Luzon generally use rice husks for feedstock, while those in Visayas mainly use bagasse, which is abundant in the area. As of October 2009, there were 18 applications for new biomass plants, totalling 248 MW, eight of which were located in Luzon and the remainder in Visayas. Two biomass plants were awarded contracts, one was for thermal heating only, and the other was a 7.2 MW plant using rice husks as a feedstock.[40]

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[36] DOE, Biomass, Solar, Wind and Ocean. Available at <www.doe.gov.ph/ER/BioOSW.htm>.
[37] DOE Power Statistics 2009. Available at <www.doe.gov.ph/EP/Powerstat.htm>.
[38] DOE, Renewable Energy Outlook, November 2009. Available at <www.doe.gov.ph/IPO%20Web/linked%20files/2009/MEIF/4.pdf>.
[39] DOE, Biomass, Solar, Wind and Ocean. Available at <www.doe.gov.ph/ER/BioOSW.htm>.
[40] DOE, Investment Portfolio 2010: Biomass. Available at <www.doe.gov.ph/IPO Web/eik10_bio.htm>.

Biomass developer Global Green Power from the UK said it would accelerate development of its 87.5-MW plant in Panay, Nueva Ecija and Bukidnon, to help deal with the power shortage in Visayas and Mindanao.[41]

9.3.5.2 Biogas

As with solid biomass, biogas is generally used for domestic heating and cooking. In terms of industrial-scale projects, a 15-MW landfill gas project was commissioned in 2008, and an 11.2-MW gasification contract was awarded in October 2009.[42]

9.3.6 Solar Energy

9.3.6.1 Solar PV

As of the end of 2009, there was 6 MW of solar PV in the Philippines. The largest solar PV project is the 1-MW grid-connected CEPALCO solar PV plant, the largest solar PV plant in Southeast Asia. The largest solar cell manufacturer in Southeast Asia, SunPower, is also located in the Philippines.[43]

Solar is widely used for rural electrification. As of April 2010, the SunPower Foundation provided equipment and technicians to install solar PV systems for 150 schools in Mindanao. These systems will power lighting, computers and internet access for about 135,000 students. SunPower will also assist 12,000 homes to obtain access to electricity through solar PV and other renewable power sources.[44]

In April 2010, the Philippine Department of Energy launched Project Access, which will install solar PV system in 55 remote communities in five provinces that are not well connected to the main grid, namely Lanao del Norte, Masbate, Palawan, Aklan and Northern Samar. Funding assistance was provided by the World Bank and the Global Environment Facility (GEF).[45]

9.3.6.2 Concentrated Solar-thermal Power

As of September 2010, there were no concentrated solar-thermal power projects in operation or in the planning stages in the Philippines.

9.3.7 Small Hydro

At the beginning of 2009, the Philippines had 55 micro hydropower systems (≤100 kW) totalling 1.08 MW which were primarily used for local rural electrification, and 55 small

[41] Philippines: Biomass firm to speed up projects amidst power crisis, ASEAN Affairs, 2 March 2010. Available at <www.aseanaffairs.com/philippines_news/energy/philippines_biomass_firm_to_speed_up_projects_amidst_power_crisis>.
[42] DOE, Investment Portfolio 2010: Biomass. Available at <www.doe.gov.ph/IPO Web/eik10_bio.htm>.
[43] Vincent S. Pérez, Status of Renewable Energy Policy in the Philippines, 2009. Available at <www.adb.org/documents/events/2009/CCEWeek/Presentation-Vincent-Perez-Energy-PHI.pdf>.
[44] SunPower Foundation Supports Rural Electrification and Educational Opportunities in the Philippines, April 2010. Available at <investors.sunpowercorp.com/releasedetail.cfm?ReleaseID=463712>.
[45] DOE, DOE and Partners Launch Project Access, April 2010. Available at <www.doe.gov.ph/rpp/news1.htm>.

hydropower plants (101-10,000 kW) totalling 91.03 MW.[46] Updated figures are not available but it was expected that small hydropower capacity would increase to 151.29 MW in 2010 with the completion of 12 new projects.[47] Hedcor, a subsidiary of the Filipino-owned management and investment company Aboitiz, is the largest small and run-of-the-river hydropower developer in the Philippines, with 38.2 MW in capacity and over 40 MW under development.[48]

9.3.8 Geothermal

The Philippines, with 1,953 MW of installed capacity, is the second largest user of geothermal energy in the world, behind only the USA. The government’s plan is to increase generating capacity to 3,037 MW by 2020, and 3,447 MW by 2030.[49] In 2009 and early 2010, the government has awarded a number of development contacts (see Table 9.7).

Table 9.7: Geothermal fields in the Philippines under development as of May 2010

Developer	Location	MW
Envent (Biliran Geothermal)	Biliran, Eastern Visayas region	N/A
Primary Energy Corp.	Sta. Lourdes, Palawan	N/A
Filtech Energy Drilling Corp./Constellation Energy	Biliran Leyte	N/A
Petroenergy Resources Corp.	Mount Makiling	20-40
APC Group	Kalinga and Apayao provinces	N/A
EDC (Energy Development Corporation)	Bacon-Manito Geothermal Production	N/A
	Mt. Ampiro, Misamis Occidental	30
	Balingasag, Misamis Occidental	20
	Lakewood, Negros Occidental	40
	Mandalagan, Negros Occidental	20
	Mt. Zion, North Cotabato Tanawon	40
	Apo	50
Chevron Geothermal Philippines Holdings	Kalinga	100
Basic Energy Corp.	Batangas	N/A
Korea International Cooperation Agency (Koica) and Philippine National Oil Co	Mainit-Sadanga, Mt. Province	80
	Buguias-Tinoc, Benguet, Ifugao	60

Source: Geothermal Energy Association, Geothermal Energy: International Market Update, May 2010. Available at <www.geo-energy.org/pdf/reports/GEA_International_Market_Report_Final_May_2010.pdf>.

9.3.9 Marine (Wave/Tidal)

There are no marine energy projects under development in the Philippines as of September 2010. However, there is interest in wave and tidal power as well as ocean thermal energy conversion (OTEC). Table 9.8 shows the areas identified as suitable for development. There are 16 proposed projects for ocean energy development in the Philippines, primarily OTEC and tidal, by Deep Ocean Power Philippines, a joint US-Philippines developer. Two projects have received development permits from the Department of Energy to proceed with testing.[50]

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[46] DOE, The Renewable Energy Outlook, 2009. Available at <www.doe.gov.ph/IPO Web/linked files/2009/MEIF/4.pdf>.
[47] Nathaniel C. Domingo, et al, Overview of mini and small hydropower in Southeast Asia, EC-ASEAN Network. Available at <www.ec-asean-greenippnetwork.net/documents/tobedownloaded/knowledgemaps/KM_overview_small_hydro_SEA.pdf>.
[48] For more information see Hedcor’s website at <www.hedcor.com/about-us.html>.
[49] Department of Energy, Philippine Energy Plan 2009-2030. Available at <www.doe.gov.ph/PEP/PEP%202009-2030.pdf>.
[50] DOE, 2010 Energy Investment Kit: Ocean. Available at <www.doe.gov.ph/IPO Web/eik10_ocean.htm>.

Table 9.8: Areas suitable for the development of marine energy in the Philippines

Type of marine energy	Areas
Ocean thermal energy	San Vicente, Ilocos Sur
	Agno, Pangasinan
	Palauig, Zambales
	Mananao, Mindoro
	San Jose, Antique
	Manukan, Misamis Occidental
	Omosmarata, Basilan
	Palaui Island, Cagayan
	Dijohan Pt., Bulacan
	Mascasco, Masbate
	Batag Island, Northern Samar
	San Francisco, Surigao del Norte
	Lamon Point, Surigao del Sur
	Lacaron, Davao del Sur
Tidal energy	Hinatuan Passage
	Bohol/Talibon Strait
	Surigao Strait
	Gaboc Strait
	Basiao Channel
	San Bernardino Strait
	Basilan Strait
	San Juanico Strait
Wave energy	Batanes Islands
	Cagayan
	Polilio Islands in Auror
	Bolinao in Pangasinan

Source: DOE, 2010 Energy Investment Kit: Ocean. Available at <www.doe.gov.ph/IPO Web/eik10_ocean.htm>.

9.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	**1/5**
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. A high debt ratio may lead to negative change in the incentive policy for renewable energy.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	1	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	0	

9.4.1 Government Structure

In May 1010, Benigno ‘Noynoy’ Aquino III, son of the previous president Corazon Aquino, from the Liberal party defeated the incumbent Lakas-Kampi-CMD party in the presidential elections. The Liberal Party promised to reform government and reduce corruption during the election. As part of its manifesto, the Liberal Party said it would work for the sustainable development of natural resources and to protect the environment. The Liberal Party also wants to increase private sector involvement in the economy.[51]

9.4.2 Government Debt

Public sector debt in the Philippines amounted to 53.9 per cent of GDP in 2008, down from 54.9 per cent in 2007. In 2009, public sector debt was expected to remain at approximately the same level as in 2008. The fiscal deficit target in 2009 was 4.1 per cent of GDP, compared to 1.9 per cent in 2009, and is projected to be 3.7 per cent in 2010.[52] The government has a deficit reduction programme and aims to balance the budget by 2013.[53]

9.4.3 Targets and Commitments

The Philippines is a signatory to the Kyoto Protocol; however, it is not an Annex 1 country and hence does not have specific GHG emissions reduction targets specified in the agreement. The government has resisted introducing a target under the Copenhagen Accord.[54] The Renewable Energy Act of 2008 has a target of 60 per cent energy self-sufficiency by 2010, and a target to increase renewable power generating capacity in the country to 12,324.71 MW by 2030, a dramatic increase of over 100 per cent from the 2009 level of 5,313 MW. As secondary targets, the government has a goal of becoming the largest wind producer in Southeast Asia and the largest producer of geothermal power in the world by 2020. There is a goal for 100 per cent of rural communities to have access to electricity by 2013, compared to 99 per cent in 2010.

Table 9.9: Philippine government commitments

GHG emissions	None
Renewable energy (RE)	None
Renewable electricity	12,324.71 MW of renewable power generating capacity by 2020 (an increase of 7,011.71 MW from 2009 levels)

Source: Department of Energy, Philippine Energy Plan 2009-2030. Available at <www.doe.gov.ph/PEP/PEP%202009-2030.pdf>.

9.4.4 Public Sentiment

Although the Bangui Windmills in Ilocos Norte have become a major tourist attraction, there is currently no published survey or study that indicates whether Filipinos are willing to pay more for renewable energy due to the subsidies given by the government to developers. There is concern that the proposed FIT system will cause consumer electricity prices to rise sharply, thus reducing their appeal.[55]

The majority of the public is still not well informed about the renewable energy strategy framework. The Department of Energy has previously identified ‘lack of public awareness of

[51] For more information see the website at <www.liberalparty.org.ph/LP2010/Platform.html>.
[52] WB, Macro-Indicators the Philippines, February 2010. Available at <go.worldbank.org/S4E6E69400>.
[53] IMF, Philippines: Staff Report for the 2010 Article IV Consultation, February 2010. Available at <www.imf.org/external/pubs/ft/scr/2010/cr1045.pdf >.
[54] Jessica Anne D. Hermosa, Philippines digs in for climate change meeting, Business World (Manila), 21 September 2010. Available at <www.bworldonline.com/main/content.php?id=18158>.
[55] Myrna M. Velasco, Policymakers urged to calibrate feed-in-tariff to avoid price shocks for renewable energy, Manila Bulletin, 27 March 2010. Available at <www.mb.com.ph/node/249816/policymaker>.

the benefits of renewable energy projects' as an obstacle to achieving its 2015 and 2020 targets.[56]

9.5 Grid Connection Risk Index

Measure		Value	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	0	**2/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	1	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

9.5.1 Functional Separation

The transmission systems operator (TSO) in the Philippines is the National Grid Corporation of the Philippines (NGCP), a privately owned company. NGCP, which is 40 per cent owned by the State Grid Corporation of China, with Monte Oro Grid Resource of the Philippines and Calaca High Power Corporation equally owning the remainder, was awarded a 25-year concession as the transmission system operator starting in January 2009, taking over from the state-owned National Transmission Company. While NGCP is the system operator and it manages the physical transmission assets, the transmission assets themselves continue to be owned by TransCo, a state-owned company that was responsible for privatising the power grid.

The distribution networks are operated by local distribution system operators (DSOs). The Small Power Utilities Group (SPUG), owned by the National Power Corporation (NPC), is responsible for providing power to remote communities.[57] All power purchases have to be cleared through the Wholesale Electricity Spot Market, the market operator.[58]

In 2009, 60.7 per cent of total generation came from power plants owned or under contract to the state-owned National Power Corporation (down from 67.7 per cent in 2008).[59] The government is continuing with the gradual privatisation of power plants, and the Public Sector Assets and Liabilities Management Corporation continues to sell off state-owned plants.[60]

[56] DOE, Renewable Energy Information. Available at <www.doe.gov.ph/ER/Renenergy.htm>.
[57] For more information see the website at <www.ngcp.ph>.
[58] For more information see the website at <www.wesm.ph/page.php?p=4>.
[59] Department of Energy, Power Situationer 2009. Available at <www.doe.gov.ph/EP/Powersituationer.htm>.
[60] See the website at <www.psalm.gov.ph/privatization.html>.

9.5.2 Grid Capacity

At the end of 2008, transmission assets amounted to 19,778 km, around half of which were located in the Luzon grid zone. Grid congestion is a problem due to rising demand and new capacity additions. The Visayas grid has needed reinforcement work for a number of years. The NGCP is proposing a number of new projects, including interconnections between the grids, in order to meet future projected demand.[61] In September 2010, the NGCP submitted a proposal for PHP 35.8 billion (EUR 591 million) for projects in 2011-2015 to enhance the transmission grid, PHP 26 billion (EUR 430 million) of which will be spent in the Luzon grid zone.[62]

9.5.3 Access and Connection Cost

Barring exceptional circumstances, developers usually obtain approval for a grid connection within two months of submission. Currently, the producer has to pay all the costs for connecting the grid. Renewable power producers are given priority connection to the grid and priority dispatch of their output into the grid.[63] Applications for grid connections are considered overly complex and a hindrance to development. Costs for obtaining grid connections are also considered to be a hindrance, particularly for small generators.[64]

9.6 Planning Permission Risk Index

Measure		**Value**	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**2/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	1	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

9.6.1 Complexity and Expected Timescales

According to the Department of Energy (DoE), there are a number of stages which prospective developers must negotiate in order to receive permits for their renewable power

[61] NGCP, 2009 Transmission Development Plan. Available at <www.ngcp.ph/tdp_frame.asp?tdp_doc=https://www.ngcp.ph/documents/2009_TDP_volume_1.pdf>.
[62] National Grid plans P35.8-B projects for next five years, Business Week (Manila), 26 September 2010. Available at <www.bworldonline.com/main/content.php?id=18436>.
[63] ERC, Resolution No. 16. Series of 2010- Resolution Adopting the Feed In Tariff Rules (7/23/2010). Available at <www.erc.gov.ph/cgi-bin/issuances/files/Resolution no. 16 series of 2010_final.pdf>.
[64] IEA, Deploying Renewables in Southeast Asia, 2010.

projects. Permission from the DoE must be obtained, as well as planning permission from local or regional authorities.[65] According to the IEA, lack of coordination between planning authorities is hindering development of renewable energy. The complexity of the planning system, and the large number of authorities that are required to be consulted, is another concern.[66]

9.6.2 Local Opposition and Procedural Improvements

As there have been relatively few renewable power developments in the Philippines it is difficult to know if public opposition will be a factor. As previously mentioned, the Department of Energy has identified 'lack of public awareness of the benefits of renewable energy projects' as an obstacle to achieving its 2015 and 2020 targets.[67] Local environmental organisations are in favour of the increased deployment of renewable energy.[68]

The government is committed to removing barriers, both fiscal and non-fiscal, to the development of renewable power in the country.[69]

9.7 Conclusion

The Philippine government has announced ambitious plans for renewable energy deployment in the country, with a focus on renewable power. While growth in renewable power deployment has been slow in recent years, apart from geothermal, the Philippines has good solar, wind and biomass resource potential and the government has set ambitious 20-year targets. There will also be a significant need for additional generating capacity to meet projected demand, and the government is encouraging private companies to invest in the power sector. At the same time, the grid operator has plans to enhance the power grid in order to handle the increased deployment.

The main barrier, as of mid 2010, is the lack of a credible incentive programme. It is hoped that the government's new FIT system, coupled with the renewable power quota requirements, will reduce this risk and create conditions where developers will be able to raise funds. However, while the proposed rules look good, the final rules and the rates for the FIT system will not be developed until early 2011 and until they are official, it is difficult to judge the affect the FIT will have on the renewable power sector in the Philippines.

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[65] DOE, The Renewable Energy Outlook, 2009. Available at <www.doe.gov.ph/IPO Web/linked files/2009/MEIF/4.pdf>.
[66] IEA, Deploying Renewables in Southeast Asia, 2010.
[67] DOE, Renewable Energy Information. Available at <www.doe.gov.ph/ER/Renenergy.htm>.
[68] WWF, WWF/DOE Trade Mission. Available at <www.wwf.org.uk/filelibrary/pdf/philmission.pdf>.
[69] Mario C. Marasigan, DOE, Renewable Energy Act of 2008, September 2009. Available at <www.usea.org/programs/EUPP/GCRE_September_2009/GCRE_Presentations/GCR_Workshop_Presentations_Monday_August-31-2009/Country_Presentations/Philippines_RE_Act_of_2008US_Global_Workshop.pdf>.

Chapter 10: Taiwan

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
Taiwan operates a feed-in tariff (FIT) system with higher tariff rates given to emerging renewable power technologies.	**5/5**

2. Power Market Opportunities Index	Value
A significant additional generating capacity will be required by 2020, while almost all fossil fuels consumed in the country are imported.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Onshore wind
Emerging Technologies Technologies that have growth potential in the country.	Offshore wind, Solar power, Marine energy

Risk Indices

4. Political Will Risk Index	Value
Deployment of renewable energy (RE) is strongly supported by all political parties and the public, while nuclear power is also supported.	**1/5**

5. Grid Connection Risk Index	Value
TaiPower, the state-owned power utility, virtually controls the entire power sector with the exception of some IPPs. Developers have complained of difficulties in obtaining grid connections.	**3/5**

6. Planning Permission Risk Index	Value
The planning process has led to delays in development. There is also local opposition to certain large development projects. Small (≤500 kW) projects are now exempt from development permits.	**2/5**

10.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.*	3	**5/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	1	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.*	1	

10.1.1 Operating Incentives

The government of Taiwan supports the development of renewable power through a feed-in tariff (FIT) system. The FIT system was originally introduced in 2001 and the rate was then set at 2,000 TWD/MWh (43.41 EUR/MWh[1]) for all technologies for 20 years of generation. The government increased the FIT rates for wind power in 2003 and for solar power in 2009. In July 2009, the Taiwanese parliament passed the Renewable Energy Development Act. This Act brought two changes: firstly, it raised the total capacity cap of the renewable power supported by the FIT system from 6.5 GW to 10 GW; and secondly, it gave the government power to revise the FIT rates. After public consultation, the government released revised FIT rates on January 2010 as shown in Table 10.1. The rates are valid for 20 years.

Table 10.1: Feed-in tariff rates in Taiwan in 2010

Category		FIT rate	
		TWD/MWh	**EUR/MWh**
Onshore wind	≤10 kW	7,271.4	157.84
	>10 kW	2,383.4	51.74
Offshore wind		4,198.2	91.13
Solar PV	≤10 kW	11,188.3	242.86
	10 – 500 kW	12,972.2	281.59
	>500 kW	11,119.0	241.36
Run-of-the-river small hydropower (≤20 MW)		2,061.5	44.75
Geothermal		5,183.8	112.52
Biomass		2,061.5	44.75
Waste		2,087.9	45.32
Other		2,061.5	44.75

Source: Bureau of Energy, 訂定「中華民國九十九年度再生能源電能躉購費率及其計算公式」， 並自即日生效 (Renewable Energy Purchase and Wholesale Price), January 2010. Available at <www.moeaboe.gov.tw/opengovinfo/Laws/secondaryenergy/LSecondaryMain.aspx?PageId=l_secondary_16>.

[1] The exchange rate used in this report is EUR 1 = TWD 46.06811 (average over the first six months of 2010).

The developer receives a reduced FIT rate for solar PV if he has obtained an investment grant as shown in Table 10.2.

Table 10.2: Solar PV feed-in tariff rates in Taiwan for projects which have been awarded an investment grant

Subsidy (TWD)	Size of PV installation	FIT rate	
		TWD/MWh	EUR/MWh
120,000	≤10 kW	5,975.8	129.72
	10 – 500 kW	4,468.4	97.00
	>500 kW	2,755.5	59.81
110,000	≤10 kW	6,602.6	143.32
	10 – 500 kW	5,095.2	110.60
	>500 kW	3,382.3	73.42
100,000	≤10 kW	7,229.4	156.93
	10 – 500 kW	5,722.1	124.21
	>500 kW	4,009.2	87.03
90,000	≤10 kW	7,856.3	170.54
	10 – 500 kW	6,348.9	137.82
	>500 kW	4,636.0	100.63
80,000	≤10 kW	8,483.1	184.14
	10 – 500 kW	6,975.7	151.42
	>500 kW	5,262.8	114.24
70,000	≤10 kW	9,109.9	197.75
	10 – 500 kW	7,602.6	165.03
	>500 kW	5,889.7	127.85

Source: Bureau of Energy, 訂定「中華民國九十九年度再生能源電能躉購費率及其計算公式」， 並自即日生效 (Renewable Energy Purchase and Wholesale Price), January 2010. Available at <www.moeaboe.gov.tw/opengovinfo/Laws/secondaryenergy/LSecondaryMain.aspx?PageId=l_secondary_16>.

For subsidies above TWD 120,000 or below TWD 70,000, the rates received by solar PV developers will be proportionally adjusted, based on the FIT rates shown in Table 10.2.

Landfill gas-based generation is not covered under the FIT system and instead receives a 500 TWD/MWh (10.85 EUR/MWh) supplement on top of the price they receive for their electricity sales. This arrangement functions as a fixed premium.[2] Under Taiwanese law, all power generated has to be purchased by TaiPower, the state-owned power company, at a set rate. In 2009, the purchase price was 1,897.9 TWD/MWh (41.20 EUR/MWh).[3] Therefore, in 2009, landfill gas-based generators received 2,379.9 TWD/MWh (51.66 EUR/MWh).

10.1.2 Investment Support

Under the latest Renewable Energy Development Act the Taiwanese government offers the following financial assistance for investment in renewable power:

- Energy tax exemption
- Two-year accelerated depreciation of capital expenses
- Reduced business taxes

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[2] 般廢棄物掩埋場沼氣發電獎勵辦法, 22 January 2003. Available at <w3.epa.gov.tw/epalaw/docfile/040420.doc>.

[3] The price is for electricity generated in April-June 2009. For more information see Taipower. Available at <www.taipower.com.tw/index>.

- Low interest loans made available from a foundation (NGO) set up by the government
- Custom duties exemption for renewable energy equipment Taiwan is not able to produce. (Tariff reduction or exemption may also be applied to equipment imported for the construction and operation of renewable energy facilities, and procedures for the application of licenses may be simplified.)

For investments in solar power, residents and corporations can receive an investment subsidy of 150,000 TWD/kW (3,070.77 EUR/kW). The subsidy can cover up to 50 per cent of capital costs.[4]

10.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**4/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	2	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

10.2.1 Energy Consumption

Primary energy consumption totalled 133.7 million tonnes of oil equivalent (Mtoe) in 2009 (see Figure 10.1). This amount was 2.3 per cent lower than 2008, which was 3.24 per cent lower than 2007. Nevertheless, during the intervening 10 years between 1999 and 2009, primary energy consumption grew at a compound annual growth rate (CAGR) of 4.9 per cent.[5] Virtually all energy sources—99.4 per cent in 2008—were imported.[6]

Final energy consumption stood at 110.9 Mtoe in 2009, a decline of 2.6 per cent from 2008. The CAGR of final energy consumption between 1999 and 2009 was 4.1 per cent.[7]

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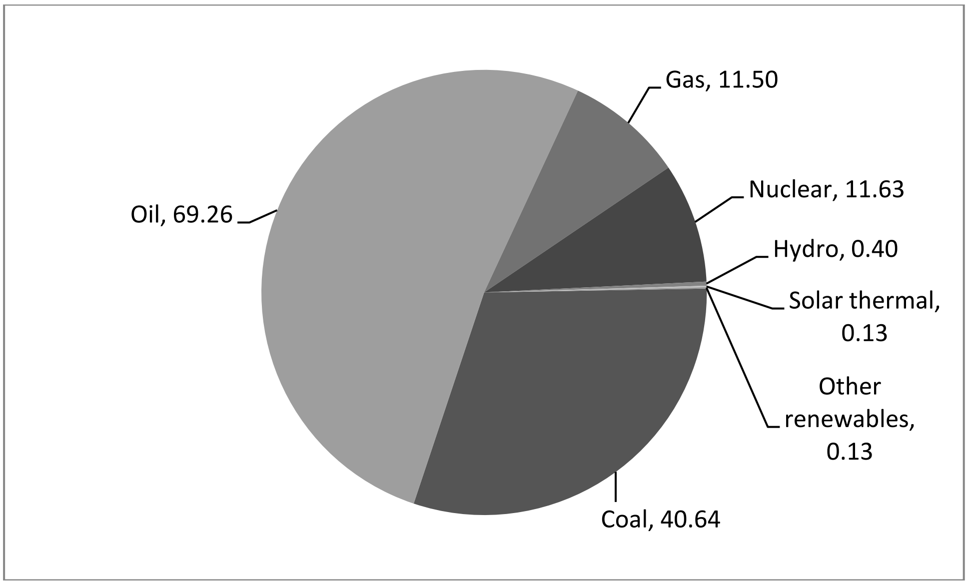
[4]再生能源發展條例 中 華 民 國 98 年7 月8 日 華 總 一 義 字 第 09800166471 號. Available at <www.moeaboe.gov.tw/opengovinfo/Laws/secondaryenergy/files/再生能源發展條例.pdf>.
[5] Bureau of Energy, Energy Supply Quarterly Report. Available at <www.moeaec.gov.tw/Download/opengovinfo/Plan/all/energy_qreport/main_en/files/02/2-1.Energy Supply (by Energy Form)(200904).pdf>.
[6] Bureau of Energy, Energy Supply: Imported and Indigenous. Available at <www.moeaec.gov.tw/Download/opengovinfo/Plan/all/energy_qreport/main_en/files/02/2-2.Energy Supply (Indigenous & Imported)(200904).pdf>.
[7] Bureau of Energy, Total Domestic Consumption (By Energy Form). Available at www.moeaec.gov.tw/Download/opengovinfo/Plan/all/energy_qreport/main_en/files/03/3-2.Total Domestic Consumption (by Energy Form)(200904).pdf>.

Figure 10.1: Primary energy consumption by source in Taiwan in 2009 (Mtoe): Total 133.7 Mtoe



Source: Bureau of Energy, Energy Supply Quarterly Report. Available at <www.moeaec.gov.tw/Download/opengovinfo/Plan/all/energy_qreport/main_en/files/02/2-1.Energy Supply (by Energy Form)(200904).pdf>.

10.2.2 Electricity Sector

Peak demand in 2009 was 31,011 MW, the second year in a row that peak demand had declined from an all-time high of 32,791 MW in 2007. Between 1999 and 2009, peak demand grew at a CAGR of 4.8 per cent.[8] In 2008, peak demand was projected to rise to 61,042 MW by 2027,[9] which would represent a CAGR of 3.8 per cent from 2009 levels and would signify a large increase in demand in 2010 (see Figure 10.2 for actual and projected peak demand between 2001 and 2020).

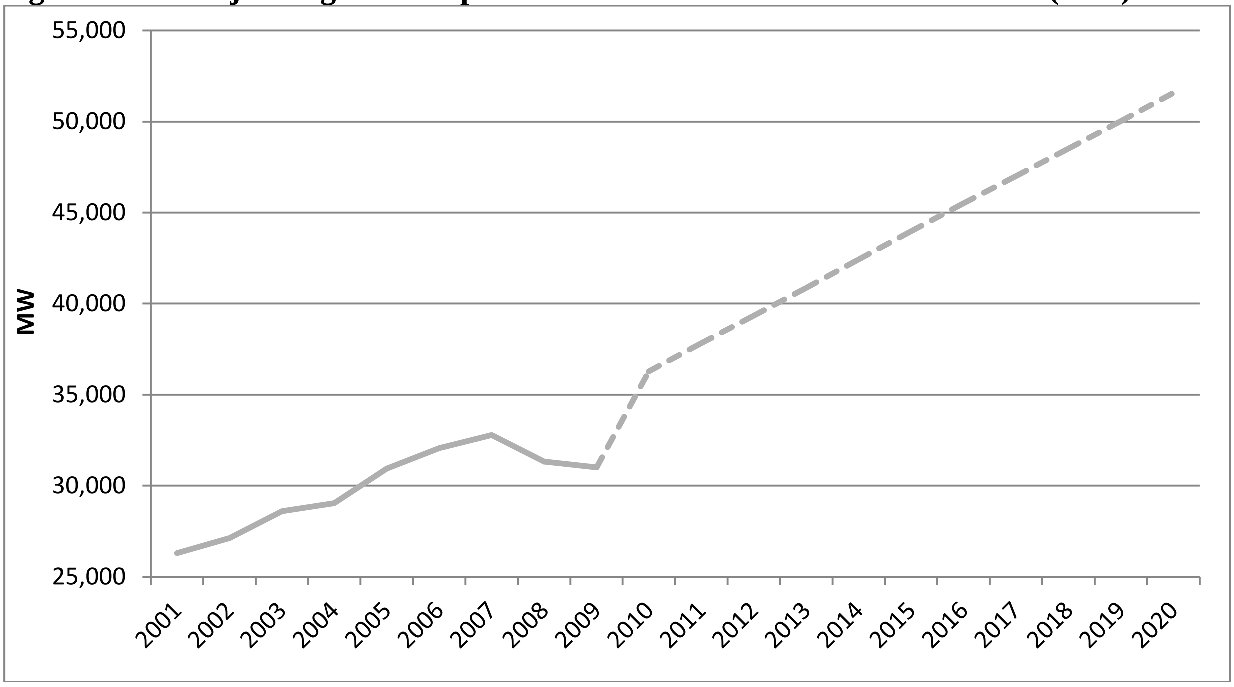
At the end of 2009, the total installed generating capacity in Taiwan stood at 48,015 MW, 62 per cent of which was fossil fuel-fired generating capacity (see Figure 10.3). Two-thirds of generating capacity was owned by TaiPower, the state-owned power company, including all the nuclear power plants. The remainder was owned by independent power producers (IPPs). Between 1999 and 2009, the total installed capacity increased at a CAGR of 3.9 per cent, or by 15,369 MW. Gas-fired generating capacity had the fastest growth during the same period.[10]

It is projected that between 2008 and 2017, 18,445 MW of generating capacity will be constructed, an increase of 38 per cent from installed capacity in 2009, while 3,554 MW of generating capacity will be retired. Gas- and coal-fired generation is expected to continue to

[8] Bureau of Energy, Energy Statistical Annual Report: Energy Indicators of Taiwan. Available at <www.moeaboe.gov.tw>.
[9] Bureau of Energy, The Report of Long-term Development of Electricity (2008-2017), 2008. Available at <www.moeaboe.gov.tw/opengovinfo/Plan/electronic/files/97-106年長期負載預測與電源開發規劃摘要報告.pdf>.
[10] Bureau of Energy, Energy Statistics Annual Reports. Available at <www.moeaec.gov.tw >.

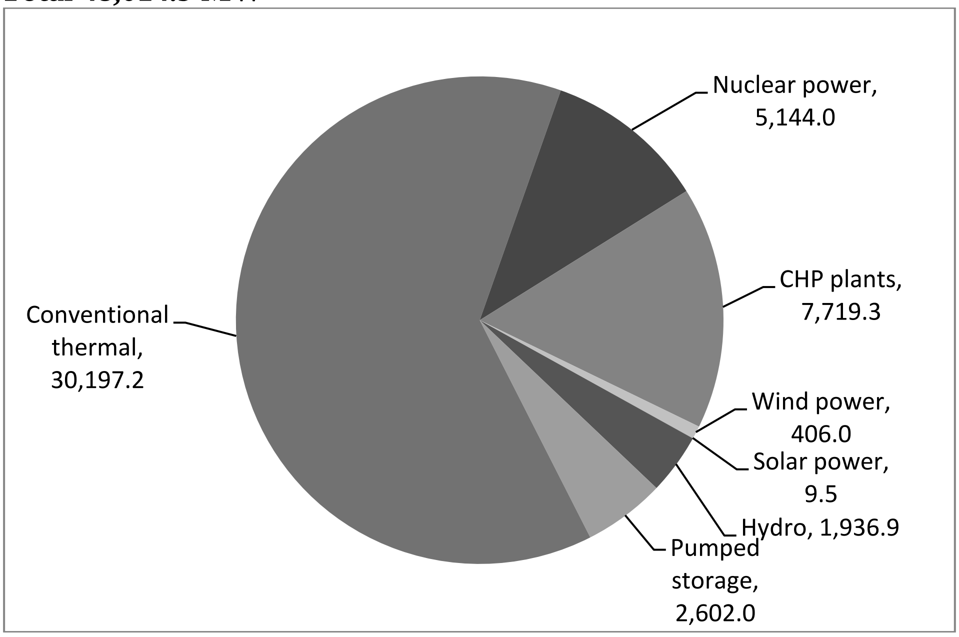
grow substantially (see Table 10.3). Gas-fired generating capacity is projected to increase to 8,000 MW by 2010 and rise to a quarter of total installed capacity by 2025.[11]

Figure 10.2: Projected growth in peak demand in Taiwan from 2001 to 2020 (MW)



Source: Bureau of Energy, Energy Statistics Annual Reports. Available at < www.moeaboe.gov.tw>; Bureau of Energy, *The Report of Long-term Development of Electricity (2008-2017)*. Available at <www.moeaboe.gov.tw/opengovinfo/Plan/electronic/files/97-106年長期負載預測與電源開發規劃摘要報告.pdf>.

Figure 10.3: Generating capacity mix in Taiwan as of 31 December 2009 (MW): Total 48,014.9 MW



Source: Bureau of Energy, Energy Statistics Annual Reports. Available at <www.moeaboe.gov.tw>.

[11] Bureau of Energy, The Report of Long-term Development of Electricity (2008-2017), 2008. Available at <www.moeaboe.gov.tw/opengovinfo/Plan/electronic/files/97-106年長期負載預測與電源開發規劃摘要報告.pdf>.

Table 10.3: Generating capacity projected to be built between 2008 and 2017

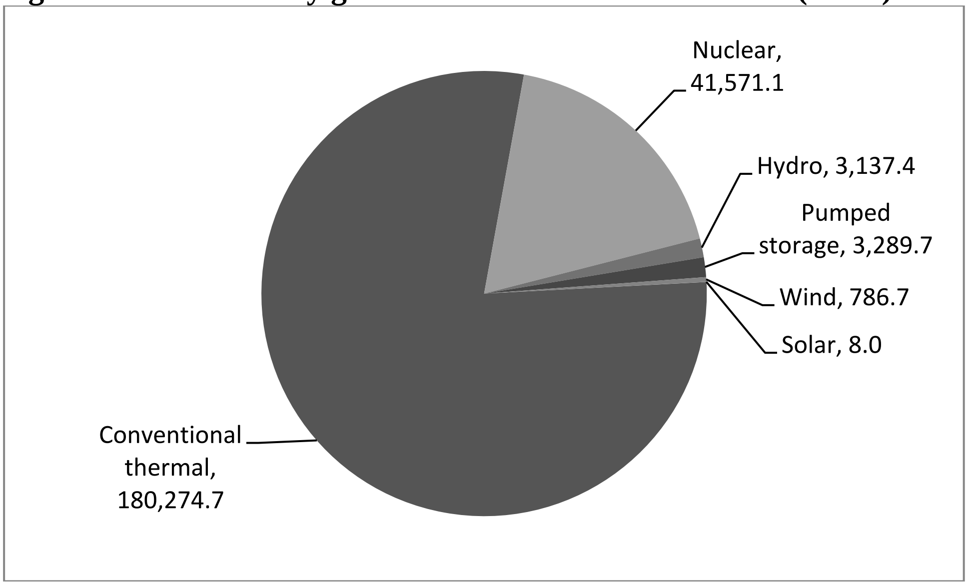
Description	Coal	Natural gas	Oil	Nuclear	Renewable
MW	7,098	5,327	109	2,700	3,211
Percentage of total build	38.5%	28.9%	0.6%	14.6%	17.4%

Source: Bureau of Energy, *The Report of Long-term Development of Electricity (2008-2017)*, 2008. Available at <www.moeaboe.gov.tw/opengovinfo/Plan/electronic/files/97-106年長期負載預測與電源開發規劃摘要報告.pdf>.

Gross electricity generation amounted to 229,067.6 GWh in 2009, down from an all-time high of 243,212 GWh in 2007. Conventional thermal generation accounted for almost 80 per cent of total generation in 2009 (see Figure 10.3).[12] In 2008, the government projected that net generation will rise to 385.94 TWh by 2027, which represents a CAGR of 2.9 per cent from 2009 levels. Renewable power generation is projected to increase to 9.8 per cent of total generation by 2017, from 6.1 per cent in 2008.[13]

Electricity consumption was 220,817.7 GWh in 2009, a decline of 4 per cent from 2008, which was 5 per cent below 2007 levels of consumption.[14] Consumption started to increase again only at the end of 2009. The government projects that electricity demand will increase by 4.64 per cent a year between 2010 and 2016, and then by approximately 2 per cent a year between 2017 and 2028.[15]

Figure 10.4: Electricity generation mix in Taiwan in 2009 (GWh): Total 229,067.6 GWh



Source: Bureau of Energy, Energy Statistics Annual Reports. Available at <www.moeaboe.gov.tw>.

[12] Bureau of Energy, Energy Statistics Annual Reports. Available at <www.moeaboe.gov.tw>.
[13] Bureau of Energy, The Report of Long-term Development of Electricity (2008-2017), 2008. Available at <www.moeaboe.gov.tw/opengovinfo/Plan/electronic/files/97-106年長期負載預測與電源開發規劃摘要報告.pdf>.
[14] Bureau of Energy, Energy Statistics Annual Reports. Available at <www.moeaboe.gov.tw>.
[15] Bureau of Energy, The Report of Long-Term Development of Load Forecasting (2009-2020). Available at <www.moeaboe.gov.tw>.

10.2.3 Nuclear Power

There are six operational nuclear reactors with a total combined capacity of 5,144 MW located at three different plants in Taiwan. All the nuclear plants are operated by TaiPower. There are two nuclear reactors under construction with a combined capacity of 2,700 MW. They are expected to become operational in 2011 and 2012. In May 2009, the government started examining the possibility of constructing an additional six reactors from 2020 onwards to increase capacity and to replace reactors that are due to be retired.[16]

10.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Onshore wind
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Offshore wind, Solar power, Marine energy

10.3.1 Renewable Electricity Generation

Wind and geothermal power have seen the fastest growth in recent years (see Table 10.4).

Table 10.4: Growth in the installed capacity of renewable power in Taiwan from 2003 to 2009 (MW)

Technology	2003	2004	2005	2006	2007	2008	2009[b]	CAGR 2003-2009 (%)
Hydro power (all)	1,908.8	1,910.7	1,909.7	1,909.7	1,921.2	1,937.9	1,936.9	0.3
Wind power	8.5	8.5	23.9	103.7	187.7	252.1	406	90.5
Solar power	0.5	0.6	1.0	1.4	2.4	5.6	9.5	63.4
Municipal solid waste	N/A	N/A	N/A	N/A	N/A	N/A	622.5	N/A
Biomass	N/A	N/A	N/A	N/A	N/A	N/A	167.5	N/A
Biogas	N/A	N/A	N/A	N/A	N/A	N/A	24.5	N/A

Note: N/A: Not available.
Source: Bureau of Energy, Energy Statistics Annual Reports. Available at < www.moeaboe.gov.tw>; [b] Bureau of Energy, Current New & Renewable Energy Utilization in Chinese Taipei, APEC New & Renewable Energy Technologies Expert Group Meeting, 26-28 April 2010. Available at <www.egnret.ewg.apec.org/meetings/engret34/APEC EGNRET 34 Chinese Taipei final.pdf>.

10.3.2 Resource Potential

Potential for renewable energy in Taiwan is significant, particularly in wind and solar power (see Table 10.5).

[16] World Nuclear Association, Nuclear Power in Taiwan, June 2009. Available at <www.world-nuclear.org/info/inf115_taiwan.html>.

Table 10.5: Taiwan's renewable energy targets

Technology	2009	2015		2025	
	MW	MW	CAGR 2009-2015	MW	CAGR 2015-2025
Hydropower	1,936.9	2,261	2.6	2,500	1.00
Wind power	406	1,480	24.1	3,000	7.3
Solar PV	9.5	320	79.7	1,000	28.8
Biomass and biogas	814.5	850	0.7	1,400	5.1
Geothermal	0	10	N/A	150	31.1
Marine energy	0	1	N/A	200	69.9
Total	3,166.90	4,922.00	7.6	8,250.00	5.3

Sources: [a]See Table 10.4 above; [b] Bureau of Energy, Overview of New and Renewable Energy in Chinese Taipei, 5 October 2009. Available at <www.egnret.ewg.apec.org/meetings/engret33/APEC EGNRET 33rd Meeting(PDF)/1. Overview of New and Renewable Energy in Chinese Taipei.pdf>.

10.3.3 Levelised Generation Costs

TaiPower publishes their levelised generation costs for onshore wind and solar PV, which were respectively 3,230 TWD/MWh (70.11 EUR/MWh) and 20,000 TWD/MWh (434.14 EUR/MWh) in 2007.[17] Table 10.6 compares the levelised generation costs and the incentives offered under the Taiwanese FIT system. The levelised generation costs for onshore wind and solar PV are for TaiPower and the rest are averages in the OECD. In general, the levelised generation costs are higher than the FIT rates offered, with the exception of offshore wind and onshore wind of 10 kW or less.

Table 10.6: Comparison of the FIT rates in Taiwan in 2010 and levelised generation costs in the OECD

Technology		FIT rates[a]		Levelised generation cost in 2007 (EUR/MWh)
		TWD/MWh	EUR/MWh	
Onshore wind	≤10 kW	7,271.4	157.84	70.11[b]
	>10 kW	2,383.4	51.74	
Offshore wind		4,198.2	91.13	85-140[c,d]
Solar PV	≤10 kW	11,188.3	242.86	434.14[d]
	10 – 500 kW	12,972.2	281.59	
	>500 kW	11,119.0	241.36	
Biomass		2,061.5	44.75	60[c,d]
Biogas		2,379.9[e]	51.66	65[c,d]
Other (wave and tidal)		2,061.5	44.75	117-195[c,d]

Notes:
[c] Figures based on a 5 per cent discount rate.
[e]Includes 500 TWD/MWh premium plus the 2009 purchase price of electricity of 1,879.9 TWD/MWh.
Sources: [a] see Incentives Opportunities Index above;
[b]TaiPower, Renewable Energy. Available at <www.taipower.com.tw/left_bar/power_life/power_development_plan/Regeneration_energy.htm>.
[d] IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

[17] Taipower, Renewable Energy. Available at <www.taipower.com.tw/left_bar/power_life/power_development_plan/Regeneration_energy.htm>.

10.3.4 Wind Power

10.3.4.1 Onshore Wind Power

Table 10.7 lists the installed capacity of onshore wind power, and the capacity under construction, or in planning, in Taiwan as of April 2010.

Table 10.7: Wind power development in Taiwan as of April 2010

Description	IPPs		TaiPower		Total	
	No. of turbines	MW	No. of turbines	MW	No. of turbines	MW
Operational	90	193	106	179	196	372
Under construction	28	64	55	108	83	172
In planning	46	106	3	60	49	112
Total	164	363	164	293	328	656

Source: Ministry of Economic Affairs, 風力發電提供淨潔能源，每年可供21萬戶家庭全年用電 (Wind Power to Provide Clean Energy), 15 April 2010. Available at <w2kdmz1.moea.gov.tw/user/news/detail.asp?id=19544>.

In April 2010, the government set a target to install 1,150 MW of onshore wind power by 2030.[18] However, given the high population density of the island, there are few suitable locations for development.[19] The German company InfraVest, one of the largest wind IPPs in Taiwan with 200 MW of wind power in operation and under construction, announced in February 2010 that it was pulling out of Taiwan as it considers the incentive offered by the government, 2,383.4 TWD/MWh (51.74 EUR/MWh), is far below the generation cost. The company estimates that its generation cost is 2,800 TWD/MWh (60.78 EUR/MWh).[20]

10.3.4.2 Offshore Wind Power

Because of frequent typhoons and earthquakes in and around Taiwan, offshore wind power development in Taiwan involves a higher level of risk than in other regions such as Europe. As of August 2010, there were no offshore wind power plants in operation or under construction. However, the government estimates the potential for offshore wind power development will be 2,000 MW by 2030. After conducting an environmental impact assessment, the government has opened up the first block of area where offshore wind can be developed, with a view for 150 MW to be installed by 2015.[21]

In October 2009, the Scottish offshore wind power developer SeaEnergy signed an agreement with Taiwan Generations Corporation, an IPP, to jointly develop a 600-MW offshore wind farm off the west coast of Taiwan in the Taiwanese Strait. The project will be located 2.5 to

[18] Ministry of Economic Affairs, 風力發電提供淨潔能源，每年可供21萬戶家庭全年用電 (Wind Power to Provide Clean Energy), 15 April 2010. Available at <w2kdmz1.moea.gov.tw/user/news/detail.asp?id=19544>.
[19] InfraVest, Policy and Wind Power Development in Taiwan. Available at <nccur.lib.nccu.edu.tw/bitstream/140.119/33949/9/302609.pdf>.
[20] AFP, German Wind Power Firm to Withdraw from Taiwan, 26 February 2010. Available at <www.france24.com/en/20100226-german-wind-power-firm-withdraw-taiwan>.
[21] Ministry of Economic Affairs, 風力發電提供淨潔能源，每年可供21萬戶家庭全年用電 (Wind Power to Provide Clean Energy), 15 April 2010. Available at <w2kdmz1.moea.gov.tw/user/news/detail.asp?id=19544>.

10 km from shore in water 30 metres deep. It is still in the early planning stages with no implementation schedule announced.[22]

10.3.5 Biomass

10.3.5.1 Solid Biomass

Municipal solid waste (MSW) is the largest source of solid biomass used for power generation in Taiwan. As of 2009, MSW-fired generating capacity was 622.5 MW at 25 incinerators. It is estimated that 70 per cent of solid waste is already incinerated at these locations.[23]

As there is limited land available in Taiwan for agricultural production, supplies of other forms of solid biomass can be difficult to procure, except in cases where industrial waste is available.[24] For example, Taiwan Sugar Company uses bagasse (fibrous waste of the sugar cane after it is crushed) and other waste from sugar production in its 184.7 MW combined heat and power (CHP) plant. Kuan Yuan Paper Manufacture Company has a 2.2-MW CHP plant using wood waste from its paper manufacturing, and similarly the Kaoshan Company, an agricultural products company, has a 25-MW CHP plant.[25]

10.3.5.2 Biogas

The government has been promoting the use of landfill gas for energy production since 1996 and there are now four landfill gas power plants with a combined capacity of 24.5 MW. The government also requires all pig farms to collect and treat pig waste to create biogas. These plants are generally small and the biogas is used primarily for self-consumption.[26]

10.3.6 Solar Energy

10.3.6.1 Solar PV

Deployment of solar PV power has been slow in Taiwan, despite its sub-tropical location and thus high solar irradiation levels. As of 2009, 9.5 MW of solar PV was installed, although the government is projecting that 28 MW of new capacity will be installed by the end of 2010.

Since 2007, the government has instituted a number of measures to increase solar power usage. Solar PV systems now have to be included in any building built by the government authorities, including schools. Local governments give grants to residential home owners for installation. It is projected that 4,000 kW of solar PV will be installed on residential houses

[22] SeaEnergy, SeaEnergy and TGC Announce Agreement to Develop Offshore Wind Farms in Taiwan, 27 October 2009. Available at <www.seaenergy-plc.com/seaenergyrenewables/Press_Releases/TGC-SERL Joint Press Release (English).pdf>.
[23] Bureau of Energy, Sustainable Development of Renewable Energy: Biomass. Available at <www.moeaboe.gov.tw/About/webpage/book_en1/page3.htm>.
[24] Bureau of Energy, The Status of Biomass Energy Industry Development in Taiwan. Available at <sourcingtaiwan.taiwantrade.com.tw/english/pdf/03_02_Biomass Energy Industry.pdf>.
[25] Renewable Energy Taiwan, Biomass. Available at <re.org.tw/Re2/Eng/biomass.aspx>.
[26] Renewable Energy Taiwan, Biomass. Available at <re.org.tw/Re2/Eng/biomass.aspx>.

by 2012.[27] The sports stadium constructed for the 2009 World Games relies entirely upon roof-based solar panels and storage batteries for all its power needs.[28]

TaiPower is building a 4.6 MW solar PV plant. The plant, built by Fortune Electric Company with panels supplied by Suntech, is expected to be operational by August 2011. TaiPower has said it expects to build more solar PV plants in the coming years.[29]

The government is encouraging the development of a domestic solar power manufacturing industry, based on Taiwan's experience in semiconductor manufacturing.

10.3.6.2 Concentrated Solar-thermal Power

No concentrated solar-thermal power projects have been implemented in Taiwan.

10.3.7 Small Hydro

As of 2009, there was 130 MW of small hydropower (≤20 MW) installed in Taiwan. In the same year, there was 1,922 MW of conventional large hydropower and 2,602 MW of pumped-storage hydropower.[30] There are few suitable locations left for further large hydropower development.

Since 2006, 30.9 MW of small hydropower projects have been developed by three IPPs. The Sieko Hydropower Plant, developed by Jainan Enterprise, was completed in 2006 with an installed capacity of 11.5 MW. The Minjan Hydropower Plant, built by Minjan Power Company, was completed in 2006 with an installed capacity of 16.7 MW. The Dongjen Hydropower Plant was completed in 2008, with an installed capacity of 2.7 MW.[31]

10.3.8 Geothermal

The government estimates that Taiwan has a potential of up to 1,000 MW of geothermal development. However, most of the suitable sites are located far from demand centres and therefore high grid connection costs may make projects financially unfeasible. Also, most of the geothermal sources that are located close to demand centres are not suitable for power production as temperatures are not high enough, although they could be developed for heat production.[32]

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[27] Bureau of Energy, Sustainable Development of Renewable Energy: Solar. Available at <www.moeaboe.gov.tw/About/webpage/book_en1/page2.htm>.
[28] Taiwan's Solar Stadium 100% Powered by the Sun, 20 May 2009. Available at <www.guardian.co.uk/environment/2009/may/20/taiwan-solar-stadium>.
[29] Sun Yu-huay, Taipower expects big solar plant to be completed next year, Taipei Times, 20 March 2010. Available at <www.taipeitimes.com/News/biz/archives/2010/03/20/2003468480>.
[30] Bureau of Energy, Sustainable Development of Renewable Energy: Hydro. Available at <www.moeaboe.gov.tw/About/webpage/book_en1/page4.htm>.
[31] Renewable Energy Taiwan, Hydro. Available at <www.re.org.tw/renew_en/knowledge/f1h1.aspx>.
[32] Bureau of Energy, Sustainable Development of Renewable Energy: Geothermal. Available at <www.moeaboe.gov.tw/About/webpage/book_en1/page5.htm>; Renewable Energy Taiwan, Biomass. Available at <re.org.tw/Re2/Eng/geothermal.aspx>.

10.3.9 Marine (Wave/Tidal)

In a white paper prepared by the Taiwanese government's Bureau of Energy in 2007, the development of marine energy was included as one of the priorities of the government. The government wants to develop tidal stream power, wave power and ocean thermal energy conversion (OTEC). Tidal barrages are not considered suitable for Taiwan for environmental reasons. Table 10.8 outlines the government's policy for marine energy development.

Table 10.8: Marine energy development policy of Taiwan

Technology	2000-2010	2015-2020
Tidal current power	To assess development potential and technologies.	To build test plants and then commercial plants.
Wave power	To investigate development potential including possible problems.	To build test plants and then commercial plants.
OTEC	To develop new methods.	To build a 100 kW test plant.

Source: Bureau of Energy, White paper on the Research and Development of Energy Technology, 2007. Available at <www.moeaboe.gov.tw/Policy/PoMain.aspx?PageId=energytechwhitepaper>.

10.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	**1/5**
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. A high debt ratio may lead to negative change in the incentive policy for renewable energy.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

10.4.1 Government Structure

In elections held in January 2008, the Pan-Blue Coalition of the Kuomintang (KMT) and two smaller parties gained 86 out of 113 seats in the Taiwanese parliament, beating the incumbent, the Democratic Progressive Party (DPP). The President, Ma Ying-jeou of the KMT, was elected in May 2008. The next legislative election is expected in 2011 or 2012, and the next presidential election in 2012.[33]

[33] CIA World Factbook.

All major political parties support the development of renewable energy.[34] Therefore, political change at least in the foreseeable future is unlikely to bring a negative effect on the renewable electricity sector. However, it took over six years for the recent Renewable Energy Development Act to be passed. One reason for this, according to politicians, was the concern over increasing the price of energy for consumers.[35] Wind power developers were also concerned that the newly formed government would be more interested in developing nuclear power and less interested in promoting renewable energy than the former government. So far the KMT has supported both nuclear and renewable energy.[36]

10.4.2 Government Debt

It is estimated that Taiwan's gross public debt amounted to 37.4 per cent of GDP in 2009, well below the legislated limit of 48 per cent. Mounting debt has, however, caused concern among investors, particularly as the government dramatically reduced taxes in 2008 to cope with the global economic recession. Notably in 2009, Fitch lowered its rating for Taiwan's debt to negative from stable. Taiwan's economy expanded 12.53 per cent year-on-year in the second quarter of 2010 and the government has projected 8.24 per cent growth for the full year.[37]

10.4.3 Targets and Commitments

In 2009, the Taiwanese government introduced new targets for GHG emissions reduction and for renewable power production (see Table 10.9). As Taiwan is not a recognised member of the UN, it is not a signatory to the UN Framework Convention on Climate Change (UNFCCC) and its Kyoto Protocol. It is aiming to obtain observer status at the UNFCCC.

Table 10.9: Taiwanese government commitments

GHG emissions	To reduce GHG emissions to 2000 levels by 2025, and half the emission levels of 2000 by 2050.
Renewable energy (RE)	A target of 15 per cent of total energy consumption to be met from renewable sources by 2020.[a]
Renewable electricity	15 per cent of total generating capacity to be from renewable energy sources by 2025.

Source: Ministry of the Environment, Visions and Realisations of a Green Island, November 2009. Available at <unfccc.epa.gov.tw/unfccc/english/_uploads/visions_and_realization_of_a_green_island.pdf>; Bureau of Energy, Current New & Renewable Energy Utilization in Chinese Taipei, APEC New & Renewable Energy Technologies Expert Group Meeting, 26-28 April 2010. Available at <www.egnret.ewg.apec.org/meetings/engret34/APEC EGNRET 34 Chinese Taipei final.pdf>.

[34] See parties' websites and 'Administration Pushes Renewable Law,' Taiwan Panorama, May 2009. Available at <www.sino.gov.tw/en/show_issue.php?id=200959805072e.txt&cur_page=1&distype=text&table=2&h1=About Taiwan&h2=Law&search=&height=&type=&scope=&order=&keyword=&lstPage=&num=&year=2009&month=05>.
[35] Vincent Choy, Renewable Energy Chokes on Price, Taipei Times, 11 February 2010. Available at <www.taipeitimes.com/News/taiwan/archives/2010/02/11/2003465704>.
[36] InfraVest, Policy and Wind Power Development in Taiwan. Available at <nccur.lib.nccu.edu.tw/bitstream/140.119/33949/9/302609.pdf>.
[37] Ted Yang, Tax revenues rising amid debt worries, Taipei Times, 2 October 2010. Available at <www.taipeitimes.com/News/biz/archives/2010/10/02/2003484311>.

10.4.4 Public Sentiment

Taiwan relies heavily on imported energy sources. Support for the development of renewable energy is strong, both to reduce GHG emissions and to improve energy security. In a 2009 poll, over 89 per cent of respondents said that they supported the development of RE despite the increased costs.[38] In another 2009 opinion poll, 70 per cent of the respondents supported replacing nuclear power with renewable energy, while 49.9 per cent of the respondents favoured keeping nuclear power as an option to reduce emissions and to ensure security of supply. Approximately three-quarters of the respondents supported changing industrial laws to reduce carbon emissions.[39]

10.5 Grid Connection Risk Index

Measure		**Value**	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	**3/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	1	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

10.5.1 Functional Separation

The state-owned TaiPower is the sole transmission and distribution system operator in Taiwan and it produces electricity that meets three-quarters of total consumption. The electricity sector is not unbundled.[40]

10.5.2 Grid Capacity

Partly because the renewable electricity development is relatively new in Taiwan, there is no clear information on the availability of grid capacity or on problems with connections.[41]

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[38] Vincent Choy, Renewable Energy Chokes on Price, Taipei Times, 11 February 2010. Available at <www.taipeitimes.com/News/taiwan/archives/2010/02/11/2003465704>.
[39] Majority in Tawain Favour Replacing Nukes with Renewables, Taiwan News, 29 December 2009. Available at <www.etaiwannews.com/etn/news_content.php?id=1143064&lang=eng_news&cate_img=logo_taiwan&cate_rss=TAIWAN_eng&pg=2>.
[40] See the Taipower website at <www.taipower.com.tw>.
[41] C. Lin, et al. Challenges of Wind Farms Connection to Future Power Systems in Taiwan/ISESCO Science and Technology Vision - Volume 4, Number 6 (November, 2008). Available at <www.isesco.org.ma/ISESCO_Technology_Vision/NUM06/ISESCO sce 6.pdf/Lin … 37-42.pdf>.

However, according to TaiPower, there is sufficient grid capacity to meet the government's targets on renewable power deployment.[42]

TaiPower invested TWD 326.6 billion (EUR 7.1 billion) in upgrading the transmission grid between 2001 and 2009. It is also investing TWD 56.8 billion (EUR 1.2 billion) in upgrading the distribution network between 2008 and 2011. It plans to continuously upgrade the grid where there is congestion.[43]

10.5.3 Access and Connection Cost

Renewable power plants whose capacities are 20 MW or larger are connected to the transmission grid. Those below 20 MW are connected to the distribution grid.[44] The entire costs for connecting to the grid need to be paid by the developer (deep connection charges). TaiPower is not allowed to refuse requests for connection by renewable power plants and has to give them priority connection.[45] InfraVest, a German wind power developer that has been active in Taiwan since 2000, has indicated that it has had problems and delays in obtaining a grid connection permit form TaiPower.[46]

10.6 Planning Permission Risk Index

Measure		**Value**	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**2/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	1	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

10.6.1 Complexity and Expected Timescales

The level of complexity in obtaining planning permission varies depending upon the size of the project. In 2009, the government issued new guidelines for projects of 500 kW or less,

[42] See the Taipower website at <www.taipower.com.tw>.
[43] Taipower, Expansion of Facilities. Available at <www.taipower.com.tw>.
[44] C. Lin, et al. Challenges of Wind Farms Connection to Future Power Systems in Taiwan/ISESCO Science and Technology Vision - Volume 4, Number 6 (November, 2008). Available at <www.isesco.org.ma/ISESCO_Technology_Vision/NUM06/ISESCO sce 6.pdf/Lin … 37-42.pdf>.
[45] Ministry of the Economy, Renewable Energy Development Act, 2009. Available at <www.moeaboe.gov.tw/>.
[46] InfraVest, Policy and Wind Power Development in Taiwan. Available at <nccur.lib.nccu.edu.tw/bitstream/140.119/33949/9/302609.pdf>.

exempting them from planning permission requirements.[47] For larger projects, the difficulty in obtaining planning permission is considered a major problem.[48] Up to eight departments need to be consulted on any project, which makes coordination difficult and the process lengthy. Those projects need to have a construction permit from the Department of Land Administration, which requires a full environmental impact assessment, and the use of the land has to be changed to allow for a power plant to be developed on it.[49]

InfraVest has complained that government bureaucracy and lack of knowledge of renewables have hindered their attempts to secure planning permission.[50]

Offshore projects are prohibited in areas of ecological significance. Also, projects are not allowed in areas designated as marine ocean parks. However, as offshore projects are planned in areas set aside by the government for development, planning permission risk is expected to be low.[51] The Law of Fishery Rights states that any offshore project must have the permission from the local fisheries authorities before being built. This permission will not be given if the project is judged to be harmful to the local fisheries or if an agreement with fishermen is not reached.[52] According to the Bureau of Energy, conflict with fishermen is a large barrier to the development of offshore renewable energy.[53]

10.6.2 Local Opposition and Procedural Improvements

Despite strong public support for renewable energy in Taiwan, TaiPower has indicated that there is significant local opposition to the development of wind and solar power plants.[54]

10.7 Conclusion

Taiwan is a densely populated island with limited natural resources. To facilitate renewable energy development, a FIT system is operated and additional financial support is provided at the time of investment.

A strong demand for electricity has returned as the global recession has ended, and a substantial increase in power demand is projected over the next 20 years, which creates opportunities for renewable power development. There is large potential for renewable energy exploitation in Taiwan, particularly for wind and solar power.

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[47] Ministry of the Economy, Renewable Energy Development Act, 2009. Available at <www.moeaboe.gov.tw/>.
[48] Confirmed in interview with head of the Taiwanese Bureau of Energy
[49] Department of Land Administration, available at <www.land.moi.gov.tw/law/chhtml/lawmain1.asp>
[50] InfraVest, Policy and Wind Power Development in Taiwan. Available at <nccur.lib.nccu.edu.tw/bitstream/140.119/33949/9/302609.pdf>.
[51] For more information see EPA, 環境影響評估法&海洋污染防治法, Available at <w3.epa.gov.tw/epalaw/Index.aspx>.
[52] Fisheries Information Service, 漁業法. Available at <www.fa.gov.tw/chnn/fishery_law/fish_law/laws.php?id=1t>.
[53] Interview with head of Taiwanese Bureau of Energy, Ye Qinq
[54] Majority in Taiwan Favour Replacing Nukes with Renewables, 29 December 2009. Available at <www.etaiwannews.com/etn/news_content.php?id=1143064&lang=eng_news&cate_img=logo_taiwan&cate_rss=TAIWAN_eng&pg=2>.

While nuclear power is strongly supported and recognised as a means of avoiding additional GHG emissions, renewable power is also backed by both political parties and the public. Despite the fact that large amounts have been invested in upgrading the power grid, developers have expressed concerns about the difficulties in obtaining connection permits. Similarly, difficulties and delays in obtaining planning permissions have also been highlighted by developers as major problems. The government has exempted small projects from planning permission requirements and designated some offshore areas for future development.

Chapter 11: Thailand

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
A system known as 'Adders,' with guaranteed purchase of the electricity generated, functions in a similar manner to a feed-in tariff (FIT). Support is provided only for 7 to 8 years.	**4/5**

2. Power Market Opportunities Index	Value
There will continuously be a large increase in power demand and thus generating capacity; however, it is not certain how much of the additional capacity requirement will result in an increase of renewable power capacity.	**4/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Biogas
Emerging Technologies Technologies that have growth potential in the country.	Solar PV

Risk Indices

4. Political Will Risk Index	Value
There is strong political support for renewable energy (RE) development as a means to increase energy security, although there is also moderate support for the development of nuclear power and rising energy prices could reduce support.	**2/5**

5. Grid Connection Risk Index	Value
The grid operator is the state-owned Electricity Generating Authority of Thailand (EGAT), which is also the largest generator in the country. EGAT is legally required to connect all renewable power installations to the grid, although obtaining authorisation for grid connection is considered to be overly complex.	**3/5**

6. Planning Permission Risk Index	Value
There is some public opposition to the development of power plants in local communities. Overall, the planning process has been simplified although the planning process is considered to be overly complex. Very few large projects have been implemented and as a result it is difficult to determine the risks.	**2/5**

11.1 Incentive Opportunities Index

Measure		Value	
Primary Support Mechanism	Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs). *This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets*.	3	**4/5**
Duration of Incentives	One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).	0	
Emerging Technology Support	One point if the primary support mechanism provides greater relative support for the development of emerging technologies. *A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity*.	1	

11.1.1 Operating Incentives

The power generation market in Thailand comprises the state-owned generator, the Electricity Generating Authority of Thailand (EGAT), and independent power producers (IPPs). IPPs with up to 60 MW in capacity of combined heat and power (CHP) or renewable power plants, referred to as Small Power Producers (SPP), and those whose capacity is less than 10 MW, called Very Small Power Producers (VSPP), are both eligible to receive incentives for their generation.

EGAT is legally obliged to purchase all the electricity delivered to the grid by the SPPs and VSPPs at a fixed base tariff, which is equal to 70 per cent of EGAT's avoided cost by not building or operating a new power plant. In April 2010, the base tariff was 2,500 THB/MWh (57.15 EUR/MWh[1]).[2] SPPs and VSPPs which are running CHPs with fossil fuels receive supplementary payments based on their operation hours in addition to the base tariff, and SPP and VSPP generators using renewable energy sources receive technology-specific supplements, known as 'Adders' (see Table 11.1), in addition to the base tariff. Since the base tariff and the adders are set by the government in advance and there is an obligatory purchase of the renewable power by EGAT, who not only generates power but also operates the network, the incentive system in Thailand can be regarded as a feed-in tariff (FIT) system.

For biomass and biogas projects over 10 MW, the Adder is set through a bidding process where developers submit proposed Adders and the successful bidder wins the right to develop the project. The Adder for projects over 10 MW is capped at 300 THB/MWh.

[1] The exchange rate used throughout this report is EUR 1 = THB 43.7443 (the average rate over the first six months of 2010).
[2] EGAT, Annual Report 2009, April 2010. Available at <www.egat.co.th>.

Table 11.1: Adders (supplementary payments) for renewable electricity in Thailand in 2010

Technology		Adder THB/MWh	Adder EUR/MWh	Duration (years)
Biomass and biogas	≤1 MW	500	11.43	7
	>1-10 MW	300	6.86	
Municipal solid waste	Anaerobic digestion/ landfill gas	2,500	57.15	7
	Combustion	3,500	80.01	
Wind power	≤50 kW	4,500	102.87	10
	>50 kW	3,500	80.01	
Solar power		8,000	182.88	10
Small hydro	<50 kW	1,500	34.29	7
	50-200 kW	800	18.29	

Source: EPPO, สรุป การปรับปรุงแนวทางการส่งเสริมการผลิตไฟฟ้าจากพลังงานหมุนเวียน (Summary of Update Guidelines to Promote Electricity from Renewable Energy Source), 9 March 2552 (2009). Available at <www.eppo.go.th/power/new_adder_policy.pdf>.

The adder generators can receive will be increased by 1,000 THB/MWh (22.86 EUR/MWh), or 1,500 THB/MWh (34.29 EUR/MWh) for wind and solar power, if their plants are replacing diesel generators in remote areas, or if they are located in the southern provinces of Yala, Pattani or Narathivath, where investment risks are considered to be higher.[3]

The adders will be available until the government-set targets on annual capacity addition are reached (see Table 11.2).

Table 11.2: Government-set caps of accumulated total capacity in Thailand

Technology	Targets (accumulated capacity total) 2011	2012-2016	2017-2022
Biomass	2,800	3,220	3,700
Solid waste	78	130	160
Biogas	60	90	120
Solar	55	95	500
Wind	115	375	800
Small hydro	165	281	324

Source: Ministry of Energy, Thailand's Renewable Energy and its Energy Future: Opportunities and Challenges. Available at <www.energy.go.th/moen/upload/File/Activity/Renew_Energy_Book%281%29.pdf>.

Part of the power generated by the SPPs and VSPPs is often used for off-grid consumption, for example, by local factories to reduce the amount of power needed from the public grid or because there is a lack of additional capacity on the public grid. Therefore, the actual contract output (rather than nameplate capacity rating) is used to define whether the facility is classified as an SPP or VSSP and to calculate the annual capacity addition for the above-mentioned capacity cap.

11.1.2 Investment Support

The government offers soft loans for renewable energy projects up to a a maximum of THB 50 million (EUR 1 million). Those loans are typically for a seven-year repayment period and have an interest rate below 4 per cent per annum. The government has also established the

[3] Ministry of Energy, Thailand's Renewable Energy and its Energy Future: Opportunities and Challenges. Available at <www.energy.go.th/moen/upload/File/Activity/Renew_Energy_Book%281%29.pdf>.

Energy Service Co (ESCO) Venture Capital Fund, a public-private venture, with THB 500 million in public financing raised through a levy on fossil fuel use and an equal amount of private investment. The ESCO fund acts as a minority partner in a project (maximum 20 per cent of equity) and usually has an agreement that the ESCO fund will sell their shares in seven years. At the end of 2009, the fund had co-invested in 29 projects, totalling THB 400 million.[4] Investment grants for biogas, municipal solid waste, and solar hot water projects are available to cover between 10 and 30 per cent of design and capital investment costs. These grants focus on small projects.[5]

In 2007, the government approved a policy allowing the emissions credits trading under the Kyoto Protocol's CDM (Clean Development Mechanism).[6] As of June 2010, 35 CDM projects had been fully approved, including 29 biogas projects. An additional 107 projects were approved by the Thai government and are awaiting approval from the CDM committee.[7]

The investment incentives an investor receives depends upon the location of the project. The government has divided Thailand up into three zones for investment purposes (see Table 11.3). Depending on the zone the following benefits are available:

- A corporate income tax holiday of eight years (an additional 50 per cent reduction for five years in Zone 3)
- A 100 per cent reduction in import taxes and duties for equipment and raw materials depending on the investment zone (see Table 11.3).

Table 11.4 details the different investment incentives available in the different zones in Thailand. There are additional non-tax investment incentives such as faster processing of work permits for experts and land ownership rights for foreigners.[8]

Table 11.3: Thai economic zones

Zone	Provinces
Zone 1	Bangkok, Samut Prakarn, Nakorn, Pathom, Nonthaburi, Pratum Thani and Samut Sakorn
Zone 2	Suphan Buri, Ayudhya, Nakorn Nayok, Chachoengsao, Chonburi, Ratchburi, Samut Songkram, Saraburi, Kanchanburi and Ang Thong
Zone 3	All other provinces plus the Laem Chabang Industrial Estate in the province of Chonburi

Source: Board of Investment, Investment Opportunities in Thailand, 2008. Available at <www.business-in-asia.net/thailand/seattle08_presentation.pdf>.

[4] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[5] Energy Policy and Planning Office, Alternative Energy, Cogeneration and Distributed Generation: Crucial Strategy For Sustainability Of Thailand's Energy Sector, August 2008. Available at <www.eppo.go.th/doc/Piya-RE-in-Thailand.pdf>.
[6] Energy Policy and Planning Office, Alternative Energy, Cogeneration and Distributed Generation: Crucial Strategy For Sustainability Of Thailand's Energy Sector, August 2008. Available at <www.eppo.go.th/doc/Piya-RE-in-Thailand.pdf>.
[7] Institute for Global Environmental Strategies, CDM Country Fact Sheet: Thailand, June 2010. Available at <enviroscope.iges.or.jp/modules/envirolib/upload/984/attach/thailand_final.pdf>.
[8] Board of Investment, Alternative Energy, 2008. Available at <www.boi.go.th/English>; Board of Investment, Investment Opportunities in Thailand, 2008. Available at <www.business-in-asia.net/thailand/seattle08_presentation.pdf>.

Table 11.4: Investment incentives available in different economic zones in Thailand

Zone	Inside industrial estates/parks	Outside industrial estates/parks
Zone 1	Three-year corporate income tax exemption	50 per cent reduction of import duties on machinery if import tariff is at least 10 per cent
	50 per cent reduction of import duties on machinery if import tariff is at least 10 per cent	Exemption of import duties on raw materials used for the manufacture of exports
	Exemption of import duties on raw materials used for the manufacture of exports	
Zone 2	Seven-year corporate income tax exemption[a]	Three-year corporate income tax exemption
	Exemption of import duties on machinery	50 per cent reduction of import duties on machinery if import tariff is at least 10 per cent
	Exemption of import duties on raw materials used for the manufacture of exports	Exemption of import duties on raw materials used for the manufacture of exports
Zone 3	Eight-year exemption of corporate income tax	Eight-year exemption of corporate income tax
	Exemption of import duties on machinery	Exemption of import duties on machinery
	A further 50 per cent reduction of corporate income tax for five years after the eight-year tax holidays end	25 per cent deduction from net profits of infrastructure construction and installation costs for 10 years
	Double deduction of transportation, water and electricity costs for 10 years	Exemption of import duties on raw materials used for exports
	25 per cent deduction from net profits of infrastructure construction and installation costs for 10 years	
	75 per cent reduction of import duties on raw materials used for domestic market[a] (not applicable in Laemchabang and Rayong)	
	Exemption of import duties on raw materials used for exports	

Note: [a]Applications must be submitted by December 2014.
Source: Opportunities with Thailand Board of Investment, 2009. Available at <www.swecham.com/attachments/058_newsfile_226_167.pdf>.

11.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**4/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	2	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

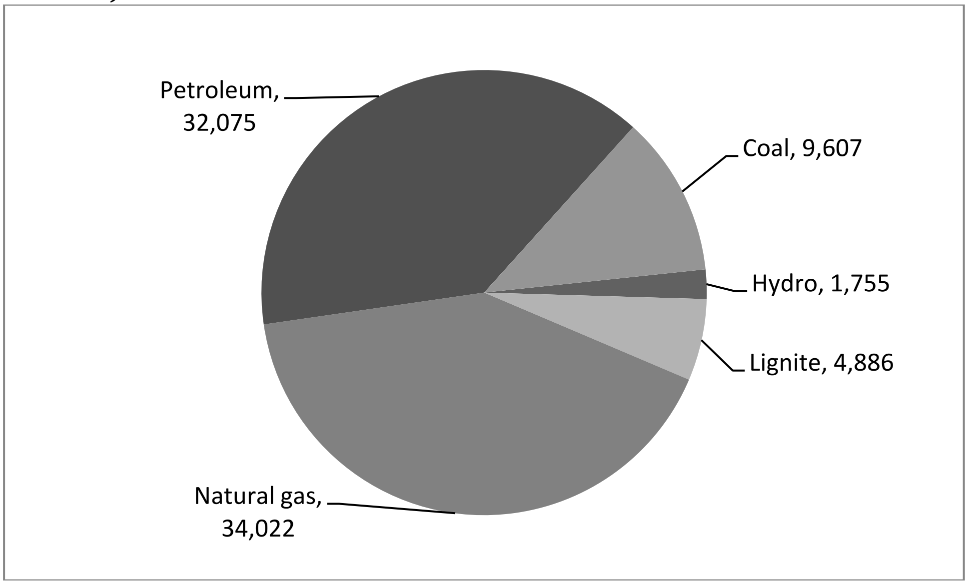
11.2.1 Energy Consumption

Thailand's primary energy consumption was 82.35 million tonnes of oil equivalent (Mtoe) in 2008. Natural gas and oil accounted for the bulk of primary energy consumption (see Figure 11.1). There was a substantial growth in primary energy consumption in the past few decades. From 1986, when it was 16.86 Mtoe, to 2009, primary energy consumption increased at a compound annual growth rate (CAGR) of 7.4 per cent. Natural gas had the fastest growth in consumption with a CAGR of 11.2 per cent during the same period.[9] As GDP growth is projected to average about 5 per cent a year, energy consumption is expected to double every 10 years.[10]

In 2009, 55 per cent of primary energy sources were imported. Since the 1980s, the country's dependency on imported energy sources has remained at between 55 and 62 per cent with oil the largest imported energy source. There are depleting gas reserves in the Gulf of Thailand and coal reserves in the north of the country, and as those reserves continue to decrease and energy demand continues to increase, the country's dependency on imported energy sources will increase. In this context, renewable energy is becoming more important to the country. However, it is a view commonly held by those involved in the energy sector in Thailand that the potential for renewable power deployment is limited and that the country needs to expand coal-fired power to meet increasing power demand.[11]

Final energy consumption was 56.69 Mtoe in 2009. It grew at a CAGR of 7.1 per cent between 1986 and 2009.[12]

Figure 11.1: Primary energy consumption by source in Thailand in 2009 (ktoe): Total 82,345 ktoe



Source: Energy Policy and Planning Office, Energy Statistics: Summary. Available at <www.eppo.go.th/info/1summary_stat.htm>.

[9] Energy Policy and Planning Office, Energy Statistics: Summary. Available at <www.eppo.go.th/info/1summary_stat.htm>.
[10] World Bank Asia Alternative Energy Program, Thailand. Available at <go.worldbank.org/WDUBCQ2T60>.
[11] An interview held with officials at ESCO, a subsidiary company of EGAT.
[12] Energy Policy and Planning Office, Energy Statistics: Summary. Available at <www.eppo.go.th/info/1summary_stat.htm>.

11.2.2 Electricity Sector

Peak demand in 2009 was 22,956 MW. From 4,220 MW in 1986 until 2009, peak demand increased at a compound annual growth rate (CAGR) of 7.6 per cent, despite a demand decrease in 1998 and 1999 after the 1997 Asian financial crisis.[13] In April 2010, EGAT revised its projection for peak demand in 2020 due to the current recession at 36,366 MW (compared to 44,281 MW projected in 2009) and 65,547 MW by 2030 (see Figure 2). From 2009 levels, this would represent a CAGR of 4.3 per cent up to 2020 and 6 per cent from 2020 to 2030.[14]

Total electricity consumption in 2009 was 135,209 GWh, a 0.2 per cent decrease from 2008 levels.[15] Between 1985 and 2009, power consumption increased at a CAGR of 8.6 per cent.[16]

Total installed grid-connected generating capacity was 30,607 MW in 2009. Gas-fired power plants accounted for just over half of total capacity (see Figure 11.3). There was an additional 15,971 MW of off-grid capacity in the same year, for a total installed generating capacity of 46,578 MW. EGAT, the state-owned power monopoly, owned 52 per cent of generating capacity in 2009. Independent power producers (IPPs) owned the remainder, mostly gas-fired plants, selling their output under contract to EGAT.[17]

To meet increasing demand, the total installed grid-connected capacity is projected to grow at a CAGR of 3.5 per cent between 2009 and 2020, to 44,842.0 MW. Just under 6,000 MW of currently operational capacity is expected to be retired by then, and an additional 21,564 MW is projected to be built. By 2030, total installed capacity is projected to reach 65,547 MW, 54,005 MW of which will be generating capacity added to the system after 2010.[18]

Gross electricity generation amounted to 148,364 GWh in 2009, almost three-quarters of which came from gas-fired generation (see Figure 11.4). From 25,428 GWh in 1986 and 2008, gross generation grew at a compound annual growth rate (CAGR) of 7.9 per cent.[19]

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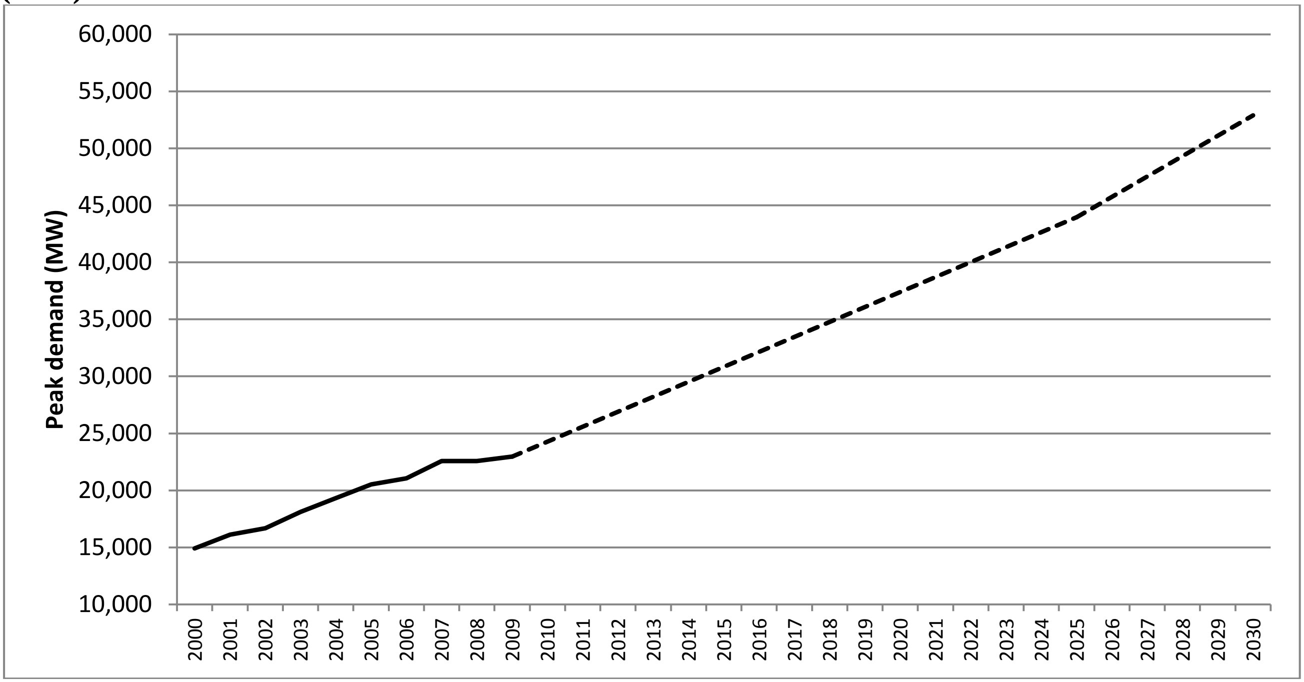
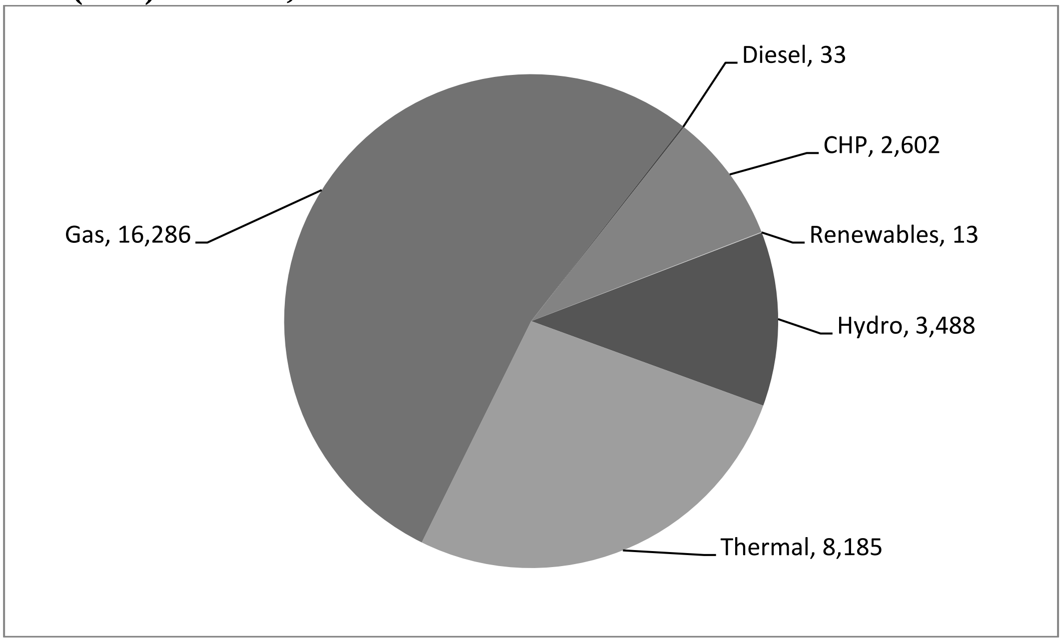
[13] Energy Policy and Planning Office, Ministry of Energy, Electricity Statistics. Available at <www.eppo.go.th/info/5electricity_stat.htm>.
[14] EGAT, Thailand Power Development Plan 2010-2030, April 2010. Available at <www.egat.co.th/en/images/stories/pdf/Report PDP2010-Apr2010_English.pdf>.
[15] Department of Alternative Energy Development and Efficiency, Electric Power in Thailand 2009. Available at <www.dede.go.th/dede/images/stories/stat_dede/ElectricPowerinThailand2009.pdf>.
[16] Energy Policy and Planning Office, Ministry of Energy, Electricity Statistics. Available at <www.eppo.go.th/info/5electricity_stat.htm>.
[17] Department of Alternative Energy Development and Efficiency, Electric Power in Thailand 2009. Available at <www.dede.go.th/dede/images/stories/stat_dede/ElectricPowerinThailand2009.pdf>.
[18] EGAT, Thailand Power Development Plan 2010-2030, April 2010. Available at <www.egat.co.th/en/images/stories/pdf/Report PDP2010-Apr2010_English.pdf>.
[19] Energy Policy and Planning Office, Ministry of Energy, Electricity Statistics. Available at <www.eppo.go.th/info/5electricity_stat.htm>.

Figure 11.2: Growth in peak demand in Thailand from 2000 and projections to 2030 (MW)



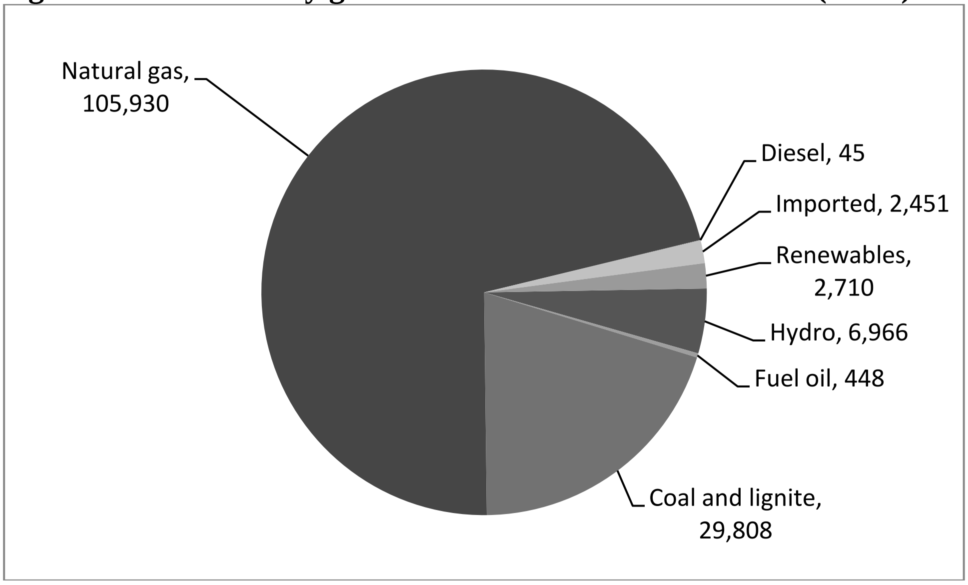
Source: Energy Policy and Planning Office, Ministry of Energy, Electricity Statistics. Available at <www.eppo.go.th/info/5electricity_stat.htm>; EGAT, Thailand Power Development Plan 2010-2030, April 2010. Available at <www.egat.co.th/en/images/stories/pdf/Report PDP2010-Apr2010_English.pdf>.

Figure 11.3: Grid-connected generating capacity mix in Thailand as of 31 December 2009 (MW): Total 30,607 MW



Source: Department of Alternative Energy Development and Efficiency, Electric Power in Thailand 2009. Available at <www.dede.go.th/dede/images/stories/stat_dede/ElectricPowerinThailand2009.pdf>.

Figure 11.4: Electricity generation mix in Thailand in 2009 (GWh): Total 148,364 GWh



Source: Energy Policy and Planning Office, Ministry of Energy, Electricity Statistics. Available at <www.eppo.go.th/info/5electricity_stat.htm>.

11.2.3 Nuclear Power

As of 2010, there were no nuclear plants in operation or under construction in Thailand, although the government has indicated its interest in constructing nuclear power plants. EGAT is studying the potential of completing 5,000 MW of nuclear by 2028, with the first 1,000 MW coming online in 2020.[20] EGAT is expected to submit its application for construction to the government in early 2011.[21]

11.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Biogas
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV

11.3.1 Renewable Electricity Generation

Total installed capacity of renewable power is projected to grow quickly between 2009 and 2016, but thereafter rather slowly. Of all generating technologies, biomass is expected to have

[20] EGAT, Thailand Power Development Plan 2010-2030, April 2010. Available at <www.egat.co.th/en/images/stories/pdf/Report PDP2010-Apr2010_English.pdf>.
[21] Egat: Nuclear plant faces more delays, Bangkok Post, 30 September 2010. Available at <www.bangkokpost.com/business/economics/198874/egat-nuclear-plant-faces-more-delays>.

the largest installed capacity, accounting for two-thirds of total renewable power capacity (see Table 11.5). Of the 5,607.5 MW target for 2022, just over half, 2,589 MW, is projected to be connected to the grid with the remaining serving as off-grid captive capacity.[22]

Table 11.5: Installed generating capacity of renewable power in Thailand at the end of 2009 and government targets up to 2022 (MW)

Technology	2009	2011 target		2016 target		2022 target	
	Capacity (MW)	Capacity (MW)	CAGR required from 2009 (%)	Capacity (MW)	CAGR required from 2011 (%)	Capacity (MW)	CAGR required from 2016 (%)
Solar power	38.6	55	19.4	95	11.6	500	31.9
Wind power	5.13	115	373.5	375	26.7	800	13.5
Small hydro power	56	165	71.7	281	11.2	320	2.2
Biomass	2,544	2,800	4.9	3,220	2.8	4,000	3.7
Biogas	37.5	60	26.5	120	14.9	160	4.9
Municipal solid waste	5.6	78	273.2	90	2.9	120	4.9
Hydrogen	0	0	N/A	0	N/A	3.5	N/A
Total	1,750	3,273	10.4	4,191	5	5,607.5	5.9

Note: N/A: Not applicable
Source: Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.

To meet the government's renewable energy targets, it is estimated that the total investment of both public and private sectors in renewable power and biofuels from 2009 to 2022 will amount to THB 488.3 billion (EUR 11.16 billion), including THB 382.2 billion from the private sector, THB 53 billion from the public budget, and THB 53.1 billion from state enterprises. Table 11.6 shows the estimated private-sector investment in renewable power required to meet the government's renewable energy targets.

Table 11.6: Required private sector investment in renewable power to meet Thailand's renewable energy target (THB million)

Technology	Short-term			Medium-term (2012-2016)	Long-term (2017-2022)	Total
	2009	2010	2011			
Biomass	21,925	20,340	35,050	45,510	30,640	153,465
Solid waste	1,350	6,600	4,000	7,800	4,500	24,250
Biogas	3,600	4,125	4,500	6,750	9,000	27,975
Solar	1,045	695	695	4,726	56,159	63,320
Wind	280	2,800	4,900	18,200	29,750	55,930
Total	28,200	34,560	49,145	82,986	130,049	324,940

Source: Ministry of Energy, Thailand's Renewable Energy and its Energy Future: Opportunities and Challenges. Available at <www.dede.go.th/dede/fileadmin/upload/pictures_eng/pdffile/Section_1.pdf>.

11.3.2 Resource Potential

Thailand receives relatively high solar irradiation throughout the country, with a country-wide average of 5.1 kWh/m^2 every day (1,861.5 kWh/m^2 per year). The north-east and central parts of the country, covering the provinces of Nakhon Ratchasima, Burirum, Surin, Sisaket, Roiet, Yasothon, Ubon Ratchathani, Udonthani, Suphanburi, Chainat, Ayutthaya and Lopburi

[22] EGAT, Thailand Power Development Plan 2008-2021, May 2009. Available at <www.egat.co.th/en/images/stories/pdf/PDP2007Rev2-Mar2009-Eng(wo-invest).pdf>.

(roughly 14 per cent of the total area of the country), receive the highest levels of solar irradiation of between 5.3-5.6 kWh/m^2 per day (1,934.5- 2,044 kWh/m^2 per year), a similar level to that in southern European countries such as Spain, Italy or Greece.[23]

Wind power potential is low in Thailand. It is estimated that only 761 km^2 of territory, 0.2 per cent of total, has wind speeds rated as 'good' or 'very good', i.e., exceeding 7 m/s at 65 m above ground level. The estimated potential in this area is about 3,000 MW. An additional 37,337 km^2, about 7.2 per cent of total land area, is rated as 'fair' with wind speeds of between 6-7 m/s at 65 m above ground level. The best areas for wind speeds are around the Gulf of Thailand and the central highlands.[24]

With its large agricultural industry, Thailand has ample solid biomass resources. In terms of agricultural wastes, it was estimated in 2005 that around 61 million tonnes of agricultural wastes were available every year for energy use, with 41 million tonnes, which is equivalent to 10,174 ktoe (kilotonnes of oil equivalent), unused. The most promising agricultural wastes for energy production are rice husks, bagasse, oil palm and rubber wood, all of which can be collected from mills for use at CHP plants. Waste water and agricultural manure in Thailand has the potential to produce 186 ktoe and 310 ktoe respectively (total 596 ktoe).[25] In 2008, over 6 million tonnes of agricultural wastes and 32 million m^3 of biogas were used for power generation, all in CHP plants.[26] However, it appears that a market system has not been well enough developed to market agricultural wastes away from the mill.

There is 526 ktoe of geothermal potential in Thailand; however, 96 per cent of the resources are located in the northern, less heavily populated regions.[27]

Table 11.7 shows the potential for renewable power development in Thailand, compared to the situation in 2009 and the 2022 targets.

Table 11.7: Renewable power capacity targets in 2022 and potential in Thailand

Technology	2009	2022 target	Potential
Solar power	38.6	500	>5,000
Wind power	5.13	800	1,600
Small hydro power	56	320	700
Biomass	2,544	4,000	4,400
Biogas	37.5	160	190
Municipal solid waste	5.6	120	400
Total	1,750	5,604	>12,210

Source: Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.

[23] A. Thongsathitya1, S. Janjai, K. Tohsing and J. Laksanaboonsong, 'Development of Maps from Satellite Data of Solar Energy Potential in Thailand,' Technical Digest of the International PVSEC-14, 2004. Available at <www.energy-based.nrct.go.th/Article/Ts-3 development of maps from satellite data of solar energy potential in thailand.pdf>.

[24] World Bank Asia Alternative Energy Program, Wind Energy Resource Atlas of Southeast Asia, September 2001. Available at <siteresources.worldbank.org/EXTEAPASTAE/Resources/wind_atlas_complete.pdf>.

[25] S. Prasertsan, B. Sajjakulnukit, 'Biomass and Biogas Energy in Thailand: Potential, Opportunity and Barriers,' Renewable Energy, Vol 31, Issue 5, April 2006. Available at <dx.doi.org/10.1016/j.renene.2005.08.005>.

[26] Department of Alternative Energy Development and Efficiency, Electric Power in Thailand 2008. Available at <www.dede.go.th/dede/fileadmin/usr/wpd/static/2008/EleThai2008.pdf>.

[27] DEDE, Alternative Energy Situation Thailand 2009. Available at <www.dede.go.th/dede/images/stories/stat_dede/Thailand_Alter2009.pdf>.

11.3.3 Levelised Generation Costs

Table 11.8 shows the generation compensation in Thailand in 2009 with the levelised generation cost in OECD in 2010. It can be said that wind power generation is adequately supported, even with the low wind speeds generally found in Thailand, whereas solar PV is unlikely to be feasible except in areas with high solar irradiation. Although the generation compensation of biomass generation is below the levelised generation cost, it may be adequately supported due to the wide availability of biomass fuel sources.

Table 11.8: Comparison of the generation compensation in Thailand for 2010 with levelised generation costs in the OECD

Technology	Generation compensation (THB/MWh)[a]			Generation compensation (EUR/MWh)[a]	Levelised generation cost in the OECD (EUR/MWh)[b,c]
	Price of electricity	Adder	Total		
Biomass (1-10 MW)	2,500	300	2,800	64.01	60
Biogas (1-10 MW)	2,500	300	2,800	64.01	65
Onshore wind (>50 kW)	2,500	3,500	6,000	137.16	38-111
Solar PV	2,500	8,000	10,500	240.03	143-408

Notes: [a]See Incentive Opportunities Index above.
[b] Figures based on a 5 per cent discount rate.
Source: [c]IEA, OECD and NEA, Projected Costs of Generating Electricity, 2010 edition.

11.3.4 Wind Power

11.3.4.1 Onshore Wind Power

Wind power is starting to enter the renewable power market in Thailand. At the end of 2009, 5.13 MW of onshore wind power was installed, most at a test facility run by EGAT.[28] The 2022 target is 800 MW. As of March 2010, 1,220 MW's worth of applications for wind farms between 10 MW and 90 MW, and 128 MW's worth of applications for wind farms under 10 MW were received by the government. It is not known how many of these will be developed.[29] Of those applications, 10 projects totalling 78 MW in capacity (i.e., on average, 7.8 MW each) have been approved. Those 10 projects are located in the central highlands and near the border with Laos in the provinces of Petchabun, Nakornratchasima, Chaiyaphum, Kalasin/Roi-ET and Mukdaharn.[30] EGAT plans to install 65 MW of wind power capacity between 2009 and 2017.[31] Because only limited areas are suitable for wind power development and the capacity availability of the transmission system is also limited, suitable locations for large-scale, grid-connected wind power systems may be exploited quickly.

[28] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[29] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[30] Piyasvasti Amranand, Chief Advisor to Energy for Environment Foundation, 'The Role of Renewable Energy, Cogeneration and Distributed Generation in Sustainable Energy Development in Thailand,' 20 May 2009. Available at <www.jgsee.kmutt.ac.th/jgsee1/news/090610/Keynote presentations/Day 2/Dr. Pyasvasti.pdf>.
[31] 'EGAT Set to Spend on 250 MW of Renewables,' Renewable Energy World, 29 July 2009. Available at <www.renewableenergyworld.com/rea/news/article/2009/07/egat-set-to-spend-on-250-mw-of-renewables>.

11.3.4.2 Offshore Wind Power

There are no planned offshore wind power projects in Thailand.

11.3.5 Biomass

11.3.5.1 Solid Biomass

The government has set a target of 4,000 MW of biomass-based generating capacity by 2022. As of the end of 2009, there was 2,544 MW installed, approximately half of which was connected to the grid.[32] The government is primarily promoting the development of biofuels and biomass-based heating instead of the use of biomass for power production.[33] The most promising fuel sources are paddy husk, bagasse, woodchips, palm wastes, palm shell, palm branches, straw, coconut fibre and black liquor.[34] Table 11.9 details the solid biomass potential of different feedstocks in Thailand.

Table 11.9: Solid biomass energy potential in Thailand (ktoe)

Feedstock		Potential
Sugarcane	Tops	5,210.55
	Bagasse	3,608.44
Rice	Husks	2,439.39
	Straw	12,309.40
Maize	Stalks	1,560.38
	Cobs	346.52
Cassava	Stalks	1,343.46
	Root	1,044.07
Oil palm	Fronds	66.39
	Fiber	716.53
	Shells	769.70
	Empty bunches	677.90
Coconuts	Shell	147.43
	Husks	303.07
	Fronds	283.96
Groundnut shells		4.79
Cotton stalks		2.28
Soybean residue		84.91
Sorghum residue		31.49
Rubber trees	Coal	627.40
	Fuel wood	290.06
	Fronds and leaves	93.68
	Saw dust	27.06
Pineapple stalks		415.63
Municipal solid waste (combustion)		3,629.94

Source: DEDE, Alternative Energy Situation Thailand 2009. Available at <www.dede.go.th/dede/images/stories/stat_dede/Thailand_Alter2009.pdf>.

[32] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[33] Piyasvasti Amranand, Thailand's Energy Minister, October 2006-February 2008, Alternative Energy, Cogeneration and Distributed Generation: Crucial Strategy For Sustainability Of Thailand's Energy Sector, 2008. Available at <www.eppo.go.th/doc/Piya-RE-in-Thailand.pdf>.
[34] Piyasvasti Amranand, Chief Advisor to Energy for Environment Foundation, 'The Role of Renewable Energy, Cogeneration and Distributed Generation in Sustainable Energy Development in Thailand,' 20 May 2009. Available at <www.jgsee.kmutt.ac.th/jgsee1/news/090610/Keynote presentations/Day 2/Dr. Pyasvasti.pdf>.

Although there is a large supply of agricultural waste for biomass generation, increased demand is also leading to higher prices for the biomass. The increased fuel price can make some projects financially unfeasible.[35] Biomass projects, along with biogas, are considered to be the most promising types of projects for private sector companies to receive CDM credits.[36]

11.3.5.2 Biogas

Biogas projects use agricultural wastes, in particular waste water and manure from pig and chicken farms. Other types of agricultural waste from palm oil, sugar, ethanol, tapioca starch, rubber, and cassava can also be used. As of March 2010, 180 MW of biogas installations, all under 10 MW, have applied for development permits.[37] Table 11.10 list the potential for various biogas feedstocks. The majority of the CDM projects in Thailand are biogas projects,[38] and biogas projects are considered to be one of the best types of projects for CDM emissions credits.[39]

Table 11.10: Biogas energy potential in Thailand (ktoe)

Feedstock	Potential
Animal wastes	362.61
Industrial water waste	488.88
Landfill gas	0.44

Source: DEDE, Alternative Energy Situation Thailand 2009. Available at <www.dede.go.th/dede/images/stories/stat_dede/Thailand_Alter2009.pdf>.

11.3.6 Solar Energy

11.3.6.1 Solar PV

At the end of 2009 there were 38.6 GW of solar PV installed in Thailand, although only 6 MW of that was connected to the grid, with the remainder used for off-grid applications. Interest in solar power development is growing, and as of March 2010, 536 MW of projects between 10 and 90 MW and 2,373 MW of projects under 10 MW had applied for

[35] Interview with EGCO, Energy Generating Co of Thailand.
[36] Pierre Cazelles, Thierry Lefevre, Jean-Marc Alexandre, Paper No.7: Most Promising CDM Projects in Thailand: Evaluation of Opportunities for Private sector Investment. Available at <www.thaicdmforum.net/documents/Paper 7_Promising CDM2.pdf>.
[37] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[38] Piyasvasti Amranand, Chief Advisor to Energy for Environment Foundation, 'The Role of Renewable Energy, Cogeneration and Distributed Generation in Sustainable Energy Development in Thailand,' 20 May 2009. Available at <www.jgsee.kmutt.ac.th/jgsee1/news/090610/Keynote presentations/Day 2/Dr. Pyasvasti.pdf>.
[39] Pierre Cazelles, Thierry Lefevre, Jean-Marc Alexandre, Paper No.7: Most Promising CDM Projects in Thailand: Evaluation of Opportunities for Private sector Investment. Available at <www.thaicdmforum.net/documents/Paper 7_Promising CDM2.pdf>.

development before 2015.[40] Under the government's target, only 500 MW of grid-connected solar PV will be allowed to receive the incentives.[41]

The largest grid-connected project is a 6-MW solar PV plant located in the Nakhonratchasima province, in northeastern Thailand, owned and operated by Solar Power (Korat 1) with Kyocera from Japan holding minority shares in the project. In June 2010, the World Bank's Investment Finance Corporation also purchased a 20 per cent share in the project.[42] Natural Energy Development Corporation, a joint venture of Electricity Generating Plc (EGCO), the largest IPP in Thailand, Diamond Generating Asia Ltd, a unit of Japan's Mitsubishi Corp, and CLP Thailand Renewables Ltd, a unit of Hong Kong-based CLP Holdings Ltd, announced that it would build an 84-MW solar plant in Lopburi province. The USD 37 million project is planned to be completed in 2015, with the first phase, 8 MW, connecting to the grid in June 2011.[43]

11.3.6.2 Concentrated Solar-thermal Power

No concentrated solar-thermal power projects have been implemented in Thailand.

11.3.7 Small Hydro

There is an estimated potential for over 700 MW of small hydro in Thailand.[44] At the end of 2009, 56 MW had been installed.[45] Small hydro is generally used for providing power to remote areas.[46] The north-west area of the country has the most number of small hydro projects and is considered the best place for development. There is also potential to refit irrigation dams with hydro power turbines.[47] EGAT is planning to develop 170 MW of small hydro projects between 2009 and 2017.[48]

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[40] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[41] Piyasvasti Amranand, Chief Advisor to Energy for Environment Foundation, 'The Role of Renewable Energy, Cogeneration and Distributed Generation in Sustainable Energy Development in Thailand,' 20 May 2009. Available at <www.jgsee.kmutt.ac.th/jgsee1/news/090610/Keynote presentations/Day 2/Dr. Pyasvasti.pdf>.
[42] Reuters, IFC invests $1.7 mln in Thailand solar power plant, 24 June 2010. Available at <www.reuters.com/article/idUSSGE65N04O20100624>.
[43] Reuters, Thai EGCO's unit plans $37 mln second solar power plant, 28 July 2010. Available at <www.reuters.com/article/idUKSGE66R05J20100728>.
[44] Piyasvasti Amranand, Chief Advisor to Energy for Environment Foundation, 'The Role of Renewable Energy, Cogeneration and Distributed Generation in Sustainable Energy Development in Thailand,' 20 May 2009. Available at <www.jgsee.kmutt.ac.th/jgsee1/news/090610/Keynote presentations/Day 2/Dr. Pyasvasti.pdf>.
[45] Dr.Twarath Sutabutr. Deputy Director-General, DEDE, Business Opportunities in Thailand's Renewable Energy, April 2010. Available at <www.dede.go.th/dede/fileadmin/upload/nov50/may53/6_5_53Bussiness.pdf>.
[46] EPPO, Thailand Energy Briefs. Available at <www.eppo.go.th/doc/NIO-EnergyAndNaturalResource2003.html>.
[47] Pramote Chamamahattana, Wattana Kongtahworn and Rudklao Panaram, The Small Hydropower Project as the Important Renewable Energy Resource in Thailand, December 2004. Available at < www.energy-based.nrct.go.th/Article/Ts-3 the small hydropower project as the important renewable energy resource in thailand.pdf>.
[48] 'EGAT Set to Spend on 250 MW of Renewables,' Renewable Energy World, 29 July 2009. Available at <www.renewableenergyworld.com/rea/news/article/2009/07/egat-set-to-spend-on-250-mw-of-renewables>.

11.3.8 Geothermal

EGAT operates one 300 kW geothermal power plant completed in 1978 in the Fang District in the north of the country. There is potential to develop other geothermal fields, all of which are located in the north and the north-west of the country.[49]

11.3.9 Marine (Wave/Tidal)

There are no planned marine energy projects.

11.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. *A high debt ratio may lead to negative change in the incentive policy for renewable energy*.	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	1	**2/5**
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	1	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	0	

11.4.1 Government Structure

The main motivation for the government to develop renewable energy is to reduce the dependency on imported energy sources, particularly crude oil.[50] However, due to financial concerns around the Asian economic crisis, the SPP and VSPP program were both suspended between 1997 and 2001 making financing difficult and reducing power demand.[51] Future economic concerns could also undermine support for the policies, especially if the price of electricity rises.

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[49] EPPO, Thailand Energy Briefs. Available at <www.eppo.go.th/doc/NIO-EnergyAndNaturalResource2003.html>.

[50] Piyasvasti Amranand, Thailand's Energy Minister, October 2006- February 2008, Alternative Energy, Cogeneration and Distributed Generation: Crucial Strategy For Sustainability Of Thailand's Energy Sector, 2008. Available at <www.eppo.go.th/doc/Piya-RE-in-Thailand.pdf>. Point confirmed with interview with EGCO.

[51] Piyasvasti Amranand, Thailand's Energy Minister, October 2006- February 2008, Alternative Energy, Cogeneration and Distributed Generation: Crucial Strategy For Sustainability Of Thailand's Energy Sector, 2008. Available at <www.eppo.go.th/doc/Piya-RE-in-Thailand.pdf>.

Investors have been concerned about the continuity of government policies due to continuing political instability and public protests.[52] Increasing energy security through increased renewable energy deployment has, however, been a goal of all recent governments.

11.4.2 Government Debt

Public sector debt in Thailand amount to 45.2 per cent of GDP in 2009, up from 38.2 per cent in 2008 due to stimulus spending as a result of the global economic recession. In 2009, there was a public deficit of 3.8 per cent of GDP. Due to continuing spending on stimulus measures, the government's budget for 2010/11 implies an overall deficit of between 3.5 and 5.0 per cent of GDP for that fiscal year. Under the World Bank's reference scenario, public debt is to peak at 49 per cent of GDP in 2014 before gradually decreasing. GDP growth continued to be negative in 2009, although in 2010 GDP growth is projected to be 6.2 per cent.[53]

11.4.3 Targets and Commitments

As a non-Annex I country under the UN Framework Convention on Climate Change and the Kyoto Protocol, Thailand does not have any GHG emissions reductions targets and the government has not introduced any such targets under the 2009 Copenhagen Accord. In 2009, the government introduced a target to increase the share of alternative energy in final energy consumption to 20.3 per cent by 2022. The government defines alternative energy as renewable energy plus natural gas for vehicles (NGV). In terms of only renewable energy, the target is for renewables to comprise 12.2 per cent of final energy consumption by 2022 (including biofuels), compared to 5.2 per cent in 2008. As part of the target to increase the renewable energy, the government set targets for renewable electricity (see Table 11.11).[54]

Table 11.11: Thai government commitments

GHG emissions	None
Renewable energy (RE)	12.2 per cent of final energy consumption to come from RE by 2022 (20.3 per cent to come from alternative energy).
Renewable electricity	A total of 5,607 MW of renewable power to be installed by 2022.

Source: DEDE, Alternative Energy Target of 20.4% in 2022, March 2009. Available at <www.dede.go.th/dede/fileadmin/upload/pictures_eng/pdffile/AE_Target_in_2022.pdf>.

11.4.4 Public Sentiment

According to a 2007 poll in Thailand, the economy and poverty eradication were considered the two most pressing issues, with 50 per cent and 18 per cent respectively saying each was the most important issue. The environment was far below, with only 1 per cent saying it was the most vital issue.[55] The public do appear, however, to be against the increased use of coal-

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[52] Orathai Sriring and Vithoon Amorn, 'Thai Q3 GDP Growth Slows, Outlook Better,' Reuters, 23 November 2009. Available at <www.forbes.com/feeds/afx/2009/11/23/afx7149664.html>.

[53] World Bank, Thailand Economic Monitor, June 2010. Available at <go.worldbank.org/KR2WMLPH80>.

[54] DEDE, Alternative Energy Target of 20.4% in 2022, March 2009. Available at <www.dede.go.th/dede/fileadmin/upload/pictures_eng/pdffile/AE_Target_in_2022.pdf>.

[55] Insight Asia, Thailand National Public Opinion Survey: Insights on Thailand's Political Conditions, 2007. Available at <www.iri.org/asia/thailand/2008 March 18 Survey of Thai Public Opinion, October 10-November 15, 2007 [Compatibility Mode].pdf>.

fired generation.[56] With regard to nuclear energy, opinions in the country are divided. In a 2007 poll, 31 per cent of respondents said that Thailand needed a nuclear power plant, with 40 per cent saying it did not, and the remainder were undecided.[57]

11.5 Grid Connection Risk Index

Measure		Value	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	1	**3/5**
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

11.5.1 Functional Separation

The transmission system operator (TSO) for all of Thailand is the state-owned EGAT, which is also the sole purchaser of all third-party power generation in Thailand.[58] There are two distribution system operators (DSO): the Metropolitan Electricity Authority (MEA), which operates around Bangkok, and the Provincial Electricity Authority (PEA), which operates in the rest of the country. Both of the DSOs are fully state-owned enterprises.[59]

11.5.2 Grid Capacity

Outside of developed areas, the lack of grid capacity can be a problem.[60] EGAT is upgrading the transmission network to allow for more generation, both gas-fired and renewable, and increasing the interconnectors with neighbouring countries. In 2007, the government committed THB 23 billion (EUR 467 million) to expand the distribution system run by the PEA and THB 9.2 billion (EUR186 million) to expand the distribution system run by the MEA. These projects are due to be completed by 2011.[61]

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[56] Jon Fernquest, ‘Coal-fired Power Generation in Thailand’s Future?’ Bangkok Post, September 2007. Available at <www.readbangkokpost.com/business/oil_and_energy/charting_thailands_energy_futu.php>.
[57] Forum for Nuclear Cooperation in Asia, Survey Results of Office of Atoms for Peace on The opinions of Thai people toward "Nuclear Energy" during September-October 2007. Available at <www.fnca.mext.go.jp/english/pi/topicsnews/thailand07-3.html>.
[58] EGAT, Annual Report 2007, 2008. Available at <pr.egat.co.th/all_work/annual2007/eng/E14.pdf>.
[59] For more information see the DSOs websites at <www.mea.or.th> and <www.pea.or.th>.
[60] Interview with EGCO (Electricity Generating Company of Thailand), May 2009.
[61] EGAT, Annual Report 2007, 2008. Available at <pr.egat.co.th/all_work/annual2007/eng/index_eng.htm>.

Grid capacity will not affect all renewable power projects as just over half (2,589 MW) of the 5,607.5 MW target for 2022 is projected to be connected to the grid.[62]

Developers have noted that it is difficult to export power to neighbouring countries as the interconnectors are not sufficient and the neighbouring countries cannot absorb the excess power.[63] As part of the transmission upgrade work, EGAT is upgrading the power lines to Laos from 250 kV to 500 kV to allow for increased exchange of power.[64]

11.5.3 Access and Connection Cost

Grid connections charges are considered deep as the developer has to pay for any necessary upgrades to the grid to allow generation. EGAT has to purchase all the output of a renewable power generator, although according to developers they can be reluctant.[65] The IEA has identified complex application procedures for obtaining grid connection authorisation as a barrier for renewable power deployment.[66]

11.6 Planning Permission Risk Index

Measure		Value	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**2/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	1	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	0	

11.6.1 Complexity and Expected Timescales

The planning process has been improved in Thailand, particularly for VSPPs. Previously, permits were required from many different ministries. After the creation of the Energy Ministry in 2007, only one permit from that ministry was required, along with permits from the local government for construction and development. The Energy Ministry is obliged to

[62] EGAT, Thailand Power Development Plan 2008-2021, May 2009. Available at <www.egat.co.th/en/images/stories/pdf/PDP2007Rev2-Mar2009-Eng(wo-invest).pdf>.
[63] Interview with EGCO (Electricity Generating Company of Thailand), May 2009.
[64] EGAT, Thailand Power Development Plan 2010-2030, April 2010. Available at <www.egat.co.th/en/images/stories/pdf/Report PDP2010-Apr2010_English.pdf>.
[65] Interview with EGCO (Electricity Generating Company of Thailand), May 2009.
[66] IEA, Deploying Renewables in Southeast Asia, 2010.

respond within 120 days.[67] The IEA still considers the planning system to be overly complex and the lack of a regulatory planning framework to be hindering development. [68]

In terms of local construction permits, the environmental impact assessment procedure can add significant delays, sometimes of over a year, depending on the project.[69]

11.6.2 Local Opposition and Procedural Improvements

Many local communities are against having any type of power plant in their community as they are often not properly informed about the benefits of the energy sources.[70] However, there have been relatively few large renewable power plants built and, as such, there is limited information available on potential barriers due to planning constraints.

11.7 Conclusion

Thailand has considerable gas and coal reserves and is developing nuclear power. Therefore, though there will be a considerable need for new generating capacity, renewable power is not projected to play a large role. The incentive system in the country does not provide adequate compensation for large on-grid solar PV plants and the wind resources in the country are limited, which could make wind power development difficult.

However, there is significant biomass and biogas resource potential in Thailand and the current incentive system provides adequate compensation for developers, particularly if located near a fuel source.

[67] Interview with EGCO (Electricity Generating Company of Thailand), May 2009.
[68] IEA, Deploying Renewables in Southeast Asia, 2010.
[69] Interview with EGCO (Electricity Generating Company of Thailand), May 2009.
[70] S. Prasertsana, B. Sajjakulnukit, Biomass and Biogas Energy in Thailand: Potential, Opportunity and Barriers, 2005. Available at <www.energy-based.nrct.go.th/Article/Ts-3 biomass and biogas energy in thailand potential, opportunity and barriers.pdf>.

Chapter 12: Vietnam

Executive Summary

Opportunities Indices

1. Incentive Opportunities Index	Value
An unattractive incentive regime with no fixed tariffs for renewable power.	**0/5**

2. Power Market Opportunities Index	Value
A significant additional generating capacity will be required by 2020. Vietnam will remain a net energy exporter until 2015 and nuclear power is expected to be developed.	**3/5**

3. Technology Opportunities Index	
Established Technologies Technologies that have been established in the country with sufficient resources.	Biomass, Onshore wind
Emerging Technologies Technologies that have growth potential in the country.	Solar PV

Risk Indices

4. Political Will Risk Index	Value
Deployment of renewable energy (RE) is strongly supported by the governing party, while nuclear power is also supported.	**1/5**

5. Grid Connection Risk Index	Value
Electricity Viet Nam (EVN), the state-owned power utility, virtually controls the entire power sector with the exception of some IPPs. Regulations on obtaining a grid connection are not clear.	**4/5**

6. Planning Permission Risk Index	Value
Planning procedures are not clear and there is a lack of coordination between regional and central government offices.	**2/5**

12.1 Incentive Opportunities Index

<table>
<tr><th colspan="2">Measure</th><th colspan="2">Value</th></tr>
<tr><td>Primary Support Mechanism</td><td>Three points for a feed-in tariff (FIT), two points for a premium, and one point for tradable green certificates (TGCs).
This is considered from the viewpoint of predictability of cash flow from renewable power projects. Feed-in tariff systems provide a guaranteed buyer and price. Premium systems provide a supplementary payment per unit of electricity sold by a renewable power generator on the wholesale market. Tradable green certificate systems provide revenues from wholesale electricity and certificate markets.</td><td>0</td><td rowspan="3">0/5</td></tr>
<tr><td>Duration of Incentives</td><td>One point if the incentives provided by the primary support mechanism are secure for a reasonable period (10 years as a base).</td><td>0</td></tr>
<tr><td>Emerging Technology Support</td><td>One point if the primary support mechanism provides greater relative support for the development of emerging technologies.
A primary support mechanism that includes provisions to help develop emerging technology (offshore wind, solar PV, anaerobic digestion for biogas and other similar technologies) demonstrates a long-term commitment to the development of renewable electricity.</td><td>0</td></tr>
</table>

12.1.1 Operating Incentives

While no renewable electricity feed-in tariff, premium or tradable green certificate programmes have been introduced in Vietnam, a draft decree released in 2006[1] outlines the government's position on operating incentives for the country.

Under this decree, Electricity Viet Nam (EVN), the state-owned power monopoly, encourages local electricity authorities to purchase electricity generated from renewable energy (RE) sources through the Small Power Purchase Tariffs defined by EVN. The generator and the local authority would sign power purchase agreements (PPA) that would last as long as the debt service period of project (from 7 to 10 years). There is no set tariff rate and the rate depends upon the local electricity authority.

The electricity tariff offered by EVN for each grid-connected renewable electricity project is determined by the Ministry of Industry and Trade based on a calculation of avoided cost, in other words the amount that EVN would not have to pay to develop its own project, and to provide a reasonable incentive for development. There is little information available regarding this tariff rate but it has been stated that it is currently set at approximately 65 USD/MWh (48.83 EUR/MWh)[2] for all technologies.[3]

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[1] Asia Development Bank, Vietnam Decree of Renewable Energy. Available at <www.adb.org/Clean-Energy/documents/VIE-Decree-Renewable-Energy.pdf>.
[2] The USD-EUR conversion rate used is EUR 1 = USD 1.33113 (the average over the first six months of 2010).
[3] Nhan T. Nguyen et al, Barriers to the Adoption of Cleaner and Energy Efficient Technologies in Vietnam, 2009. Available at <www.iccgov.org/iew2009/speakersdocs/Nguyen-et-al_BarriersToTheAdoptionOfCleaner.pdf>.

The lack of a clear tariff arrangement for renewable power is considered by developers as one of the largest barriers to its development in Vietnam.[4]

12.1.2 Investment Support

In 2007, the government issued new guidelines for CDM (Clean Development Mechanism) projects. Under the guidelines, CDM projects can receive lower rent for public lands and reduced land-use taxes.[5]

Investors in environmental protection projects (including renewable energy) benefit from a reduced corporate income tax for the revenue from the project. Companies investing in lower socio-economic areas receive a tax exemption for four years, and a 50 per cent reduction for the next nine years. The incentive only applies to revenue generated from the project. Renewable energy equipment can also be imported without paying custom duties and VAT.[6]

The government is developing an incentive programme for renewable energy that would comprise low-interest loans, funds for research and development, and development grants.[7]

12.2 Power Market Opportunities Index

Measure		Value	
Demand	Two points if there is a predicted need for additional generating capacity of more than 20 per cent of current capacity for the next 10 years (a compound annual growth rate (CAGR) of 1.84%), and one point if there is a predicted need of between 10 and 20 per cent (a CAGR of 0.96%). *The larger the additional generating capacity requirement, the more chance there is to deploy renewable power.*	2	**3/5**
Security	Two points if there are no significant or declining indigenous energy sources for power (including nuclear), and one point if indigenous energy sources are stable while imports are increasing to meet demand. *The greater the reliance on imported energy sources, the greater the need for renewable energy development to improve energy security.*	1	
Nuclear	One point if there is an expected decrease of nuclear capacity with no plan of replacement. *If nuclear power plants are decommissioned, there will be an increased need for non-greenhouse gas-emitting power plants.*	0	

12.2.1 Energy Consumption

Primary energy consumption in Vietnam was 46.9 million tonnes of oil equivalent (Mtoe) in 2007. With an average annual GDP growth of 7.7 per cent between 2000 and 2007, economic

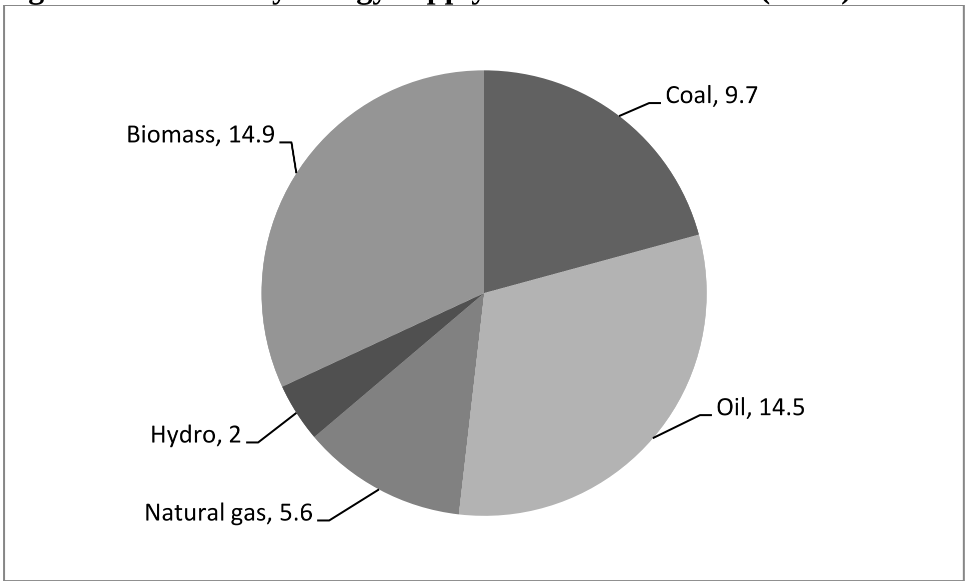
[4] Nhan T. Nguyen et al, Barriers to the Adoption of Cleaner and Energy Efficient Technologies in Vietnam, 2009. Available at <www.iccgov.org/iew2009/speakersdocs/Nguyen-et-al_BarriersToTheAdoptionOfCleaner.pdf>.
[5] CỘNG HOÀ XÃ HỘI CHỦ NGHĨA VIỆT NAM, 2007. Available at <vfu.edu.vn/ar-cdm/attdoc/webdoc_vn/pm_decision_2007-130_cdm_financial_mechanism_vn.pdf>.
[6] Department of Industry and Trade, Doanh nghiệp hoạt động bảo vệ môi trường được ưu đãi thuế, 2009. Avaialble at <www.congthuongbackan.gov.vn/so-cong-thuong-bac-kan.gplist.2.gpopen.618.gpside.1.asmx>.
[7] VIBOnline, Dự thảo Nghị định về khuyến khích, hỗ trợ phát triển năng lượng tái tạo, 2009. Available at <www.vibonline.com.vn/vi-VN/Drafts/Details.aspx?DraftID=400&Version=4>.

growth led to rising energy consumption. Between 1990 and 2007 primary energy consumption had an annual growth rate of 13.5 per cent.

The largest single source of primary energy supply in Vietnam was biomass, as most poor rural households rely solely upon biomass for heating and cooking (see Figure 12.1). However, the share of biomass in primary energy supply decreased rapidly, from 70 per cent of total primary energy supply in 1995 to 30 per cent in 2007, as communities get connected to the energy grid. The use of natural gas is increasing rapidly in Vietnam, with an annual growth rate of 33 per cent between 1995 and 2007. Due to its coal, oil and gas reserves, Vietnam is a net energy exporter. However, due to both increasing demand and reduction in reserves, Vietnam is expected to become a net importer of energy by 2015.[8]

Final energy consumption in Vietnam in 2007 was 40.5 Mtoe. Between 1995 and 2007, final energy consumption had an average annual growth rate of 14.2 per cent and from 2008/09 to 2029/30, it is projected to increase at a compound annual growth rate (CAGR) of 1.9 per cent, rising to 119.9 Mtoe by 2030.[9]

Figure 12.1: Primary energy supply in Vietnam in 2007 (Mtoe): Total 46.9 Mtoe



Source: APEC Energy Working Group, Energy Database. Available at <www.ieej.or.jp/egeda/database/>.

12.2.2 Electricity Sector

Peak demand in 2009 was 13,952 MW, a 10 per cent increase from 12,636 MW in 2008. From 5,665 MW in 2001 to 2009, peak demand grew at a CAGR of 11.9 per cent. Demand is projected to reach 15,731 MW by 2010 and then to rise to 45,197 MW by 2020, which would represent a CAGR of 10.1 per cent from 2009 levels.[10]

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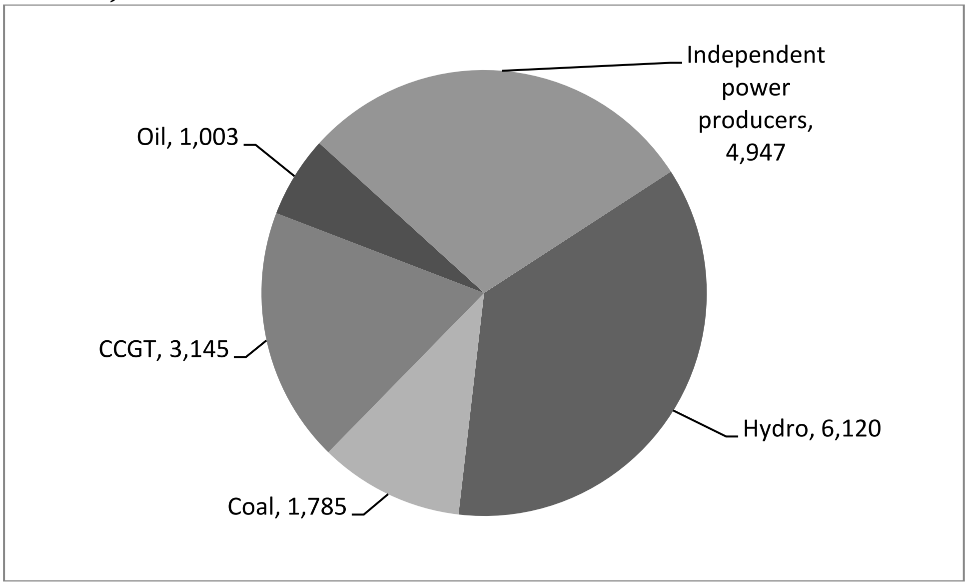
[8] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.
[9] APEC Energy Working Group, Energy Database. Available at <www.ieej.or.jp/egeda/database/>.
[10] Ministry of Industry and Trade, Tình hình phát trien mot so ngành công nghiep, 2009. Available at <www.moit.gov.vn>.

Total power consumption in 2008 was 65,293 GWh, an increase of 12.9 per cent from the previous year. From 25,858 GWh in 2001 to 2009, power consumption increased at a CAGR of 14.3 per cent.[11]

Total installed generating capacity in Vietnam at the end of 2009 was 17,000 MW, over a third of which was hydropower plants owned by EVN, the state-owned utility (See Figure 12.2). Between 2001 and 2009, total installed capacity increased at a CAGR 11.4 per cent, mostly due to new investments by independent power producers (IPPs), which increaed from approximately 500 MW in 2001 to 4,947 MW in 2009.

Figure 12.2: Total installed generating capacity in Vietnam in 2009 (MW): Total 17,000 MW



Source: Institute of Energy of Vietnam, Assessing Potential and Proposing Solution for Electricity Loss in the Power Grid in Vietnam toward 2015, 2010.

Rising demand will require new generating capacity. Despite sufficient generating capacity to meet peak demand, lack of transmission capacity and drought conditions reducing hydropower availability have caused blackouts in some areas, particularly in the summer months. A large blackout in rural areas in June 2010, just as farmers required water pumps to irrigate their crops, caused widespread protests.[12] In 2007, the government projected that USD 72.4 billion of investment in new power plants by 2025 would be needed in order to meet rising demand.[13] A total of 68 new power plants totalling 23,775 MW are projected to be built by 2015, the majority of which will be gas-fired and hydropower plants.

Gross electricity generation in 2009 was 86,948 GWh. Between 2000 and 2009, gross electricity generation increased at a CAGR of 13.9 per cent[14] and under the government's

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[11] Institute of Energy of Vietnam, Assessing Potential and Proposing Solution for Electricity Loss in the Power Grid in Vietnam toward 2015, 2010.
[12] Vietnam Officials Feel the Heat from Blackout Protests, June 2010. Available at <www.earthtimes.org/articles/news/330350,feel-heat-blackout-protests.html>.
[13] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.
[14] Institute of Energy of Vietnam, Assessing Potential and Proposing Solution for Electricity Loss in the Power Grid in Vietnam toward 2015, 2010.

baseline 'business-as-usual' scenario, gross generation is projected to increase to 286,094 GWh by 2020, which would represent a CAGR of 11.4 per cent from 2009, and then to 429,927 GWh by 2030.[15]

The Vietnamese government is encouraging foreign investment in the power sector. However, according to the Vietnam Energy Association, EVN often purchases power from IPPs below generation costs and thus foreign companies have not shown interest in investing in the power sector in Vietnam.[16] One reason for the low purchase price from EVN is the requirement that EVN provides subsidised tariffs. In 2009, the government raised the retail tariff for electricity by 13 per cent for households and 6.5 per cent for companies, thereby raising the average retail price of power to 945,000 VND/MWh (37.22 EUR/MWh).[17] Electricity rates are expected to increase by a similar amount in 2011.[18]

12.2.3 Nuclear Power

Vietnam has a plan to build a possible 13 nuclear reactors by 2030. The contract for the first nuclear power plant was agreed with Russia's Rosatom in early 2010 to build a 4,000 MW plant, with 2,000 MW completed by 2020.[19]

12.3 Technology Opportunities Index

Measure		Technology
Established Technologies	Established technologies in the country with sufficient resources. *The technologies which have been sufficiently developed and that are best suited to the conditions in the country, based on resource availability. Established technologies generally refer to onshore wind, small hydro, solid biomass combustion, landfill gas, sewage gas, etc.*	Biomass, Onshore wind
Emerging Technologies	Emerging technologies that have growth potential in the country. *The technologies which have potential in the country but have not developed sufficiently and thus require substantial financial incentives to grow. Emerging technologies generally refer to offshore wind, wave and tidal, solar PV, concentrated solar, advanced conversion forms of biomass, etc.*	Solar PV

12.3.1 Renewable Electricity Generation

The government plans for 2,451 MW of new renewable power plants to be installed in the country between 2006 and 2015, an average of 241 MW a year. Between 2016 and 2024,

15 Ministry of Industry and Trade, Tình hình phát trien mot so ngành công nghiep, 2009. Available at <www.moit.gov.vn>.
16 Ministry of Planning and Investment, Vietnam Welcomes Investors in Energy Sector, 21 August 2009. Available at <www.mpi.gov.vn/portal/page/portal/mpi_en/32343?pers_id=417323&item_id=3865267&p_details=1>.
17 'Vietnam Electricity Price Hike,' Strait Times, February 2009. Available at <www.straitstimes.com/Breaking%2BNews/SE%2BAsia/Story/STIStory_339884.html>.
18 'Investors Dismayed as EVN Turns its Back on Wind and Solar Power,' Vietnam Business News, 17 August 2010. Available at <vietnambusiness.asia/investors-dismayed-as-evn-turns-its-back-on-wind-and-solar-power/>.
19 AFP, Russia Gets Vietnam's First Nuclear Power Deal, February 2010. Available at <www.asiaone.com/News/AsiaOne+News/World/Story/A1Story20100209-197685.html>.

1,600 MW of new renewable power plants are to be built, an average of 160 MW a year.[20] The government is particularly promoting the use of renewable power for rural development. Approximately 73 per cent of the country's 85 million people live in rural areas and around 6 per cent of rural households have no access to electricity.[21]

In 2008, renewable power (excluding large hydropower) amounted to 273.2 MW, 2.35 per cent of total installed generating capacity. Biomass and small hydro comprised the majority (see Table 12.1).

Table 12.1: Total installed generating capacity of renewable power in Vietnam in 2008

Technology	Capacity (MW)	Share in total installed capacity
Wind power	1.2	0.01%
Small hydro	121.0	1.04%
Solar power	1.0	0.009%
Biomass	150	1.29%
Total	273.2	2.35%

Source: Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>.

12.3.2 Resource Potential

There is significant resource potential for renewable energy deployment in Vietnam, and there is large potential for solar power development (see Table 12.2).

Table 12.2: Solar energy resources in Vietnam by region

Region	Hours of sunshine/year	Radiation (Wh/m²/day) from April-Sept	Application possibility
The Northeast (provinces of Cao Bang, Bac Kan, Lang Son, Tuyen Quang, Thai Nguyen, Vinh Phuc, Bac Giang, Bac Ninh, Quang Ninh)	1,500-1,700	3,600	Low
The Northwest (provinces of Lai Chau, Son La, Lao Cai, Ha Giang, Yen Bai, Phu Tho, Hoa Binh)	1,750-1,900	3,500-5,831	Medium
Northern Central (the provinces from Thanh Hoa to Hue)	1,700-2,000	4,230	Good
Central Highlands (provinces of Gia Lai, Kontum, Dac Lak, Dang Nong, Lam Dong)	2,000-2,600	4,500	Very good
South Central (the provinces of Da Nang, Quang Nam, Quang Ngai, Binh Dinh, Phu Yen, Khanh Hoa)	2,000-2,600	4,500-6,500	Very good
The South	2,200-2,500	4,500	Very good
Average	1,750-2500	4,000	Good

Source: Vietnam Union of Science and Technology Associations, Assessment of Vietnam Power Development Plan, 2007. Available at <www.internationalrivers.org/files/AltPDPVietnam.pdf>.

According to the assessment of wind energy by the World Bank, Vietnam has the largest wind power potential in Southeast Asia with 100,000 MW technically feasible. Vietnam has

[20] Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>.
[21] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

'good' to 'excellent' wind speeds with 9 per cent of total area having wind speeds of 8-9 m/s, which is suitable for wind power development.[22]

With Vietnam's large agricultural sector, there are over 60 million tonnes of agricultural residues produced a year. The most promising agricultural products for RE production on an industrial scale are rice husks, bagasse, coffee husks and wood residue. Over 80,000 small-scale biogas digesters have been built to supply energy to off-grid communities and there is an estimated biogas potential of around 10 billion m^3 a year from agricultural wastes.[23] In addition to agricultural wastes, there is potential for municipal waste, both solid and biogas, to provide 42,000 GWh a year.[24]

There are 269 hot spring sites in Vietnam, of which 30 could potentially be used for geothermal power development, totalling 340 MW.[25]

Table 12.3 details the government's targets for grid-connected renewable power for 2025

Table 12.3: Renewable power targets in Vietnam for 2025 (MW)

<table>
<tr><th>Technology</th><th>Capacity in 2008[a]</th><th>Target for 2025[b]</th><th>CAGR required from 2008 levels (%)</th></tr>
<tr><td>Small hydro</td><td>121</td><td>2,050</td><td>18</td></tr>
<tr><td>Bagasse</td><td rowspan="3">150</td><td>250</td><td rowspan="3">5.6</td></tr>
<tr><td>Municipal solid waste</td><td>50</td></tr>
<tr><td>Rice husks</td><td>80</td></tr>
<tr><td>Wind power</td><td>1.2</td><td>50</td><td>25</td></tr>
<tr><td>Geothermal</td><td>0</td><td>150</td><td>N/A</td></tr>
<tr><td>Total</td><td>272.2</td><td>2,630</td><td>14.3</td></tr>
</table>

Note: N/A: Not available
Sources: [a] Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>; [b] Vu Van Thai, MOIT; Phan Thi Thuy Tien, EVN; Nguyen Duc Cuong, IE, Current New and Renewable Energy Priorities in Viet Nam, 32nd Meeting of the APEC Expert Group on New and Renewable Energy Technologies, 1- 3 April 2009, Honolulu, Hawaii, USA. Available at <www.egnret.ewg.apec.org/meetings/engret32/Vietnam RE priorities.pdf>.

12.3.3 Levelised Generation Costs

The lack of clear price signals from EVN concerning the purchase price of renewable power, is considered to be a barrier to development. A 120-MW wind farm, that has been supplying power to the grid since late 2009, had still not completed a power purchase agreement with EVN as of August 2010 as they could not agree on a price. EVN said it was unwilling to pay more than 60 to 65 USD/MWh for wind power.[26]

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[22] Vietnam Union of Science and Technology Associations, Assessment of Vietnam Power Development Plan, 2007. Available at <www.internationalrivers.org/files/AltPDPVietnam.pdf>.
[23] Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>.
[24] EVN, Untapped Power Generation from Waste, 15 July 2010. Available at <www.evn.com.vn/Default.aspx?tabid=60&TopicId=17&ItemId=4468&language=en-US>.
[25] Vietnam Union of Science and Technology Associations, Assessment of Vietnam Power Development Plan, 2007. Available at <www.internationalrivers.org/files/AltPDPVietnam.pdf>.
[26] 'Investors Dismayed as EVN Turns its Back on Wind and Solar Power,' Vietnam Business News, 17 August 2010. Available at <vietnambusiness.asia/investors-dismayed-as-evn-turns-its-back-on-wind-and-solar-power/>.

12.3.4 Wind Power

12.3.4.1 Onshore Wind Power

The Vietnamese government has a target of 950 MW of wind power by 2015 and 1,500 MW by 2020. The first utility-scale project developed in the country was a 30-MW project in the Binh Thuan province that was completed in August 2009 by Vietnam Wind Power Joint Stock Company, a Vietnamese developer, and a number of German companies. The development will qualify to receive CDM credits under the Kyoto Protocol.[27] There are plans to expand the wind farm's capacity to 120 MW. However, as of August 2010, a power purchase agreement with EVN has still not been signed. EVN is reportedly unwilling to pay the 90 to 95 USD/MWh wanted by the developer.[28]

The local authorities in Binh Dinh, Ninh Thuan and Binh Thuan provinces are promoting wind power development in their regions. There are 20 projects in various stages of development in Vietnam, and the German government in early 2010 provided a grant to study ways to improve the legal and technical ability of wind power projects to connect to the grid.[29]

12.3.4.2 Offshore Wind Power

As of September 2010, there were no offshore wind power plants in operation or development in Vietnam.

12.3.5 Biomass

12.3.5.1 Solid Biomass

Solid biomass is the largest source of primary energy consumption in Vietnam; however, this is due to the extensive use of biomass-fired cooking and heating in inefficient wood-fired stoves in rural communities.[30] The largest available resources for the development of biomass-fired electricity generation are rice husks and bagasse, with a development potential of 50 MW and 150 MW respectively.[31] In addition, there is potential for municipal solid waste.[32] However, lack of new technology for the exploitation of biomass and incentive

[27] UNFCC, Project Display. Available at <cdm.unfccc.int/UserManagement/FileStorage/R7XYG4SH3STMVPEZLSLDTXU5E791VG> and Vietnam Wind Power at <www.vwp-jsc.com>.
[28] 'Investors Dismayed as EVN Turns its Back on Wind and Solar Power,' Vietnam Business News, 17 August 2010. Available at <vietnambusiness.asia/investors-dismayed-as-evn-turns-its-back-on-wind-and-solar-power/>.
[29] 'Huge Potential for Wind Power,' Vietnam Business News, 17 July 2010. Available at <vietnambusiness.asia/huge-potential-for-wind-power/>.
[30] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.
[31] USAID, Clean Energy Solutions for Asia: Vietnam. Available at <usaid.eco-asia.org/programs/cdcp/reports/Ideas-to-Action/annexes/Annex 6_Vietnam.pdf>.
[32] EVN, Untapped Power Generation from Waste, 15 July 2010. Available at <www.evn.com.vn/Default.aspx?tabid=60&TopicId=17&ItemId=4468&language=en-US>.

policy is hindering development.[33] The government's main policy in terms of biomass energy is to replace old inefficient biomass stoves with newer and cleaner models.[34]

12.3.5.2 Biogas

Since the 1960s, over 80,000 biogas facilities have been built in Vietnam, primarily small-scale units to serve rural households.[35] With over 17,000 farms and 36.2 million livestock as of 2007, there is significant potential for the development of biogas from agricultural wastes. In addition, landfill and waste water gas have also not been widely developed in the country.

There have been a number of industrial-scale biogas plants developments. Dong Nam, a brewery in Hanoi, has installed a biogas digester for waste water from the brewing process, and a sugar cane and food production company have also installed biogas digesters to deal with waste water. However, the biogas industry in Vietnam is primarily focussed on small-scale projects. The focus on the small-scale over the industrial-scale is primarily due to the high cost of large-scale equipment, the lack of experience in operation and maintenance, and the lack of strategies, policies and incentives for development.[36]

12.3.6 Solar Energy

12.3.6.1 Solar PV

Solar PV development in Vietnam is primarily used for rural electrification and not for grid-connected projects. There were approximately 2.4 MW of solar PV connected in Vietnam at the end of 2008. Of that, 50 per cent were used for industrial projects such as street lighting, telecommunications equipment and navigation beacons; 30 per cent were located on public buildings; and 20 per cent was for household use. The government has a target of 250 MW of solar PV by 2025, primarily as a means to electrify off-grid rural communities.[37]

A number of international aid agencies and governments have provided grants for rural electrification programmes that use solar PV. In 2009, the Spanish government provided USD 12.3 million to electrify 10 remote and mountainous communes in the Quang Binh province.[38]

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[33] Dr. Thanh Nguyen-Thien, Ministry of Science and Technology, Biomass Utilization Development in Vietnam. Available at <www.biomass-asia-workshop.jp/biomassws/01workshop/material/Thanh Nguyen-Thien(Vietnam).pdf>.
[34] Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>.
[35] Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>.
[36] Methane to Market, Update of Agriculture Activities: Vietnam, Agriculture Subcommittee Meeting, 2-5 March 2010. Available at <www.methanetomarkets.org/documents/events_ag_20100305_vietnam_update.pdf>.
[37] Trinh Qung Dung, Photovoltaic Technology and Solar Energy Development in Viet Nam, Tech Monitor, Nov/Dec 2009. Available at <www.techmonitor.net/techmon/09nov_dec/tm/pdf/09nov_dec_sf3.pdf>.
[38] Remote Areas in Central Vietnam to Get Solar Power, Vietnam News, March 2009. Available at <www.vietnewsonline.vn/News/Society/Sci-Tech/5505/Remote-areas-in-central-Vietnam-to-get-solar-power.htm>.

In 2009, the first solar module manufacturer in Vietnam, Red Sun Energy, started operation. In the first phase, a total of 4 MW of solar modules a year will be manufactured, rising to 25 MW in later stages. Approximately 40 per cent of the output is expected to be used for the local market, with the remainder destined for export.[39]

12.3.6.2 Concentrated Solar-thermal Power

No concentrated solar-thermal power projects have been implemented in Vietnam.

12.3.7 Small Hydro

Vietnam is rich in hydropower.[40] Under the government's target, small hydropower (≤30 MW) is projected to increase from 121 MW in 2008 to over 2,000 MW in 2025.[41] The government has identified 408 potential sites for development, where facilities between 1 and 30 MW might feasibly be constructed, for a total additional generating capacity of 2,887 MW.[42]

One reason for the projected growth in small hydropower is that the generation cost, at 600,000 VND/MWh (23.63 EUR/MWh[43]), is already competitive with other sources of energy without the need for additional incentives.[44] However, some developers have complained that the price offered by EVN for power fed into the grid is not high enough to warrant development.[45]

12.3.8 Geothermal

There are 269 hot spring sites in Vietnam, 30 of which have been identified as potential sites for geothermal power development. Development plans for a total of 92.2 MW of geothermal power have been submitted: 55.2 MW in Quảng Ngãi province, 26.7 MW in Khánh Hoà province and 15.3 MW in Bình Định province.[46] A 50-MW project in Quảng Ngãi has applied for CDM credits for development.[47]

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[39] Tom Cheyney, First Solar PV Module Manufacturer Opens in Vietnam, Solar Buzz, 27 April 2009. Available at <www.pv-tech.org/news/_a/first_solar_pv_module_factory_opens_in_vietnam/>.
[40] Ninh Kieu (2004), Vietnam se trong cho vao nang luong tai tao, 2004. Available at<nl-taitao.blogspot.com/2005/05/nng-lng-ti-to-vit-nam.html>.
[41] Vu Van Thai, MOIT; Phan Thi Thuy Tien, EVN; Nguyen Duc Cuong, IE, Current New and Renewable Energy Priorities in Viet Nam, 32nd Meeting of the APEC Expert Group on New and Renewable Energy Technologies, 1- 3 April 2009, Honolulu, Hawaii, USA. Available at <www.egnret.ewg.apec.org/meetings/engret32/Vietnam RE priorities.pdf>.
[42] USAID, Clean Energy Solutions for Asia: Vietnam. Available at <usaid.eco-asia.org/programs/cdcp/reports/Ideas-to-Action/annexes/Annex 6_Vietnam.pdf>.
[43] Currency conversions calculated at EUR 1 = VND 25,389.29448 (the average over the first six months of 2010).
[44] Ministry of Natural Resources and the Environment, Năng lượng tái tạo: Hướng đi cho các nước châu Á, 2007. Available at <www.monre.gov.vn/MONRENET/default.aspx?tabid=214&ItemID=37002>.
[45] USAID, Clean Energy Solutions for Asia: Vietnam. Available at <usaid.eco-asia.org/programs/cdcp/reports/Ideas-to-Action/annexes/Annex 6_Vietnam.pdf>.
[46] Vietnam Union of Science and Technology Associations, Assessment of Vietnam Power Development Plan, 2007. Available at <www.internationalrivers.org/files/AltPDPVietnam.pdf>.
[47] Ministry of Natural Resources, Kyoto Protocol and CDM Activities in Vietnam. Available at <www.cd4cdm.org>.

12.3.9 Marine (Wave/Tidal)

There were no wave or tidal projects in planning or under development in Vietnam as of September 2010.

12.4 Political Will Risk Index

Measure		Value	
Political Drivers	One point if politically committed targets for renewable energy and GHG emissions reductions are projected to be met, thereby reducing the future need for renewable energy expansion. *If the government meets its commitments, then it may reduce the level of effort to promote renewable energy development.*	0	**1/5**
Government Debt	One point if the government debt exceeds 60 per cent of the GDP. *A high debt ratio may lead to negative change in the incentive policy for renewable energy.*	0	
Political Change	One point if political change brought about by major opposition parties could negatively affect renewable electricity development.	0	
Public Opposition	One point if there is a sign that the general public is becoming apathetic about or less supportive of renewable electricity because they have come to think that the targets are unattainable or because they are unwilling to pay an additional cost for supporting renewable electricity development.	0	
Nuclear Support	One point if there is a lack of significant opposition to nuclear expansion or if the government or general public becomes more supportive of nuclear power.	1	

12.4.1 Government Structure

The Communist Party of Vietnam is the only legal political party in Vietnam. The party and government support the development of renewable energy as a way in which to inexpensively electrify the country whilst limiting environmental damage. This support has been shown through policies that encourage the production and use of renewable electricity.

In 2004, in recognition of the importance of renewable energy in general, and particularly for off-grid electrification, the Vietnamese National Energy Policy stated that the ‘development of various forms of renewable energy needs to be encouraged’.[48] Subsequent laws have reiterated these points. The Renewable Energy Master Plan VI, finalised in 2009, states that priority for development would be given to low-cost sources such as small scale hydro, wind, geothermal and biomass power from bagasse, municipal solid waste, and rice husks. Priority will also be given to off-grid projects related to rural electrification, where the costs of renewable energy development are lower than diesel power or connection to the national grid.[49] Nuclear power is also seen by the government as a way to help meet Vietnam’s future power demand.[50]

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[48] Nguyen Duc Cuong, Institute of Energy, Experience of the Institute of Energy in the Preparation of the Renewable Master Plan, 2008. Available at <www.vsre.org.vn/UserFiles/File/Day 2/2. RE week in Hanoi (Cuong - IE) (e).pdf>

[49] Samantha Olz and Milou Beerepoot, Deploying Renewables in Southeast Asia: Trends and potentials, 2010. International Energy Agency.

[50] AFP, Russia Gets Vietnam’s First Nuclear Power Deal, February 2010. Available at <www.asiaone.com/News/AsiaOne+News/World/Story/A1Story20100209-197685.html>.

12.4.2 Government Debt

Public sector debt in Vietnam rose to 46.5 per cent of GDP in 2009, and is forecast to increase to 47.5 per cent of GDP in 2010. External debt amounts to 36.0 per cent of GDP in 2009, rising to 36.5 per cent in 2010, with the remainder of the debt held domestically. The fiscal deficit in 2009 also rose to 9.7 per cent of GDP in 2009, but is projected to decrease to 6.2 per cent in 2010.[51] The IMF considers a fiscal deficit of over 9 per cent unstable in the long term, but believes the government's plan to reduce the deficit is feasible, particularly as GDP is projected to continue growing at over 6 per cent per year from 2010.[52] Vietnam's debt rating was, however, reduced in June 2010 due to concern over inconsistent implementation of fiscal measures.[53]

12.4.3 Targets and Commitments

As a non-Annex I country, Vietnam has no Kyoto Protocol emissions target. The government has not introduced a target under the 2009 Copenhagen Accord. The government has set targets for renewable energy use in commercial primary energy consumption (which includes only energy products that are sold and therefore excludes rural consumption of biomass collected from their area that is not purchased) and renewable power (see Table 12.4).

Table 12.4: Vietnamese government commitments

GHG emissions	None
Renewable energy (RE)	By 2020, 5 per cent commercial primary consumption to come from RE sources, rising to 11 per cent by 2050. All rural off-grid communities to use RE sources to meet heating and hot water demand by 2020.
Renewable electricity	Between 2006 and 2015, 2,451 MW of renewable power to be completed, and between 2016 and 2025, 1,600 MW to be completed. Renewable power has to comprise 3.1 per cent of grid-connected installed capacity by 2015, and 3.8 per cent in 20205 (excluding large hydro).

Source: Vu Van Thai, MOIT; Phan Thi Thuy Tien, EVN; Nguyen Duc Cuong, IE, Current New and Renewable Energy Priorities in Viet Nam, 32nd Meeting of the APEC Expert Group on New and Renewable Energy Technologies, 1- 3 April 2009, Honolulu, Hawaii, USA. Available at <www.egnret.ewg.apec.org/meetings/engret32/Vietnam RE priorities.pdf>.

12.4.4 Public Sentiment

There is very little information available on public sentiment. The Solar Back Khoa Company has provided water heating systems to restaurants and hotels and has received positive feedback due to a reduction in costs. In general, however, the public are reluctant to use renewable electricity if the price is high.[54]

[51] World Bank, Vietnam: Key Economic Indicators, 2010. Available at <go.worldbank.org/KPB5TK9CF0>.
[52] IMF, Kien Giang, Vietnam – Informal Mid-year Consultative Group Meeting: Statement by IMF Staff Representative, June 2010. Available at <www.imf.org/external/np/dm/2010/060910.htm>.
[53] Jason Folkmanis, Vietnam's Debt Rating Lowered by Fitch on Foreign Borrowing, `Weak' Banks, Bloomberg, 29 July 2010. Available at <www.bloomberg.com/news/2010-07-29/vietnam-s-debt-rating-lowered-by-fitch-on-foreign-borrowing-weak-banks.html>.
[54] Nang cao vi the cong nghe, sang pham nang luong mat troi back khoa. Available at <www.bk-idse.com/vi/tin-moi-nhat/40-tin-tren-bao-bk/160-nang-cao-vi-the-cong-nghe-sp-nang-luong-tai-tao-mtbk.html>.

12.5 Grid Connection Risk Index

Measure		Value	
Non-Discriminatory Access	One point if the transmission function is not legally separated from generation. *If the transmission system operator is controlled by an incumbent, it may be difficult for new generators to obtain non-discriminatory access to the transmission grid*.	1	**4/5**
Availability and Clarity	Two points if capacity constraints are leading to substantial delays or if there is a lack of information about grid capacity availability. This is reduced to one point if preferential access is given to renewable electricity.	2	
Costs	One point if developers have to pay for all grid-enhancement work, or if the fees for grid connections or balancing are clearly higher than those in other EU countries.	1	
Investment	One point if additional resources to enhance the grid to allow connection of renewable electricity development projects are not being invested.	0	

12.5.1 Functional Separation

The state-owned company Electricity of Viet Nam (EVN) is the sole owner of all transmission and distribution system operators in Vietnam. EVN is also the sole purchaser of grid-connected power from independent power producers (IPPs). The largest electricity generators, all owned by EVN, are Electricity Company No. 1 (in the north), Electricity Company No. 2 (in the south) and Electricity Company No. 3 (in the central area). The distribution system operators, again owned by EVN, manage the distribution system in Hanoi, Ho Chi Minh City, Hai Phong and Dong Nai provinces. Other important members of EVN include four transmission system operators and equipment supply companies.

In 2006, the government announced a plan to liberalise the power sector. By 2011, EVN is to lose its monopoly position and generators will be able to complete. However, only in 2015 is there to be a competitive wholesale power marker, with a competitive retail market only starting by 2022.[55] As part of these reforms, EVN will be reformed and its subsidiaries privatised. Transmissions, distribution and generation will be separated (unbundled), although it is expected that the transmission system will remain in state hands.[56]

12.5.2 Grid Capacity

Due to projected increased power demand in the country, investment in expanding the grid is continuing. Between 2006 and 2025, it is expected that USD 36.3 billion will be invested in the grid system. Vietnam also has interconnectors with Laos, Cambodia and China and it is expected that Vietnam will import power from these countries, particularly China.[57]

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[55] Ministry of Industry and Trade, Workshop on Competitive Power Market in Vietnam, 18 August 2010. Available at <www.moit.gov.vn>.
[56] Vietnam Law and Legal Forum, Electricity Law: A Legal Framework for the Development of Vietnam's Competitive Electricity Market. Available at <news.vnanet.vn/vietnamlaw/>.
[57] Asia Pacific Energy Research Centre, APEC Energy Overview 2009, 2010. Available at <www.ieej.or.jp/aperc/2009pdf/Overview2009.pdf>.

12.5.3 Access and Connection Cost

There is a lack of a clear legal basis for gaining connection to the grid, which results in uncertainty about potential development of projects.[58]

12.6 Planning Permission Risk Index

Measure		Value	
Clarity	One point if there is a lack of coordination between relevant government offices or if the complexity of approval procedures is widely acknowledged as a problem. *Complex planning procedures lead to significant delays and costs during the planning process.*	1	**2/5**
Time	Two points if it normally takes more than one year to obtain approval and the situation is deteriorating (within one year is considered best practice by the industry). One point if it normally takes more than one year, but the situation is improving.	0	
Refusals	One point if refusal rates are rising or local opposition is clearly delaying projects.	0	
Improvement	One point if the government is not trying to improve planning procedures even if they are known to be a problem. *Without government intervention, particularly in local approval procedures, problems with issuing permits could worsen as more development projects seek permission.*	1	

12.6.1 Complexity and Expected Timescales

There is a lack of a coherent planning policy for on-grid renewable power projects. The procedures for approval and the authority for making decisions are not clear, which can create problems for investors. There is also a lack of coordination between different governmental bodies involved in the power sector, and the planning process can vary dramatically between the regions.[59]

12.6.2 Local Opposition and Procedural Improvements

As most renewable power development in Vietnam has been used for rural electrification, there is not much information concerning large-scale projects. For rural projects, costs are the primary concern.[60]

[58] Nhan T. Nguyen et al, Barriers to the Adoption of Cleaner and Energy Efficient Technologies in Vietnam, 2009. Available at <www.iccgov.org/iew2009/speakersdocs/Nguyen-et-al_BarriersToTheAdoptionOfCleaner.pdf>.

[59] Nhan T. Nguyen et al, Barriers to the Adoption of Cleaner and Energy Efficient Technologies in Vietnam, 2009. Available at <www.iccgov.org/iew2009/speakersdocs/Nguyen-et-al_BarriersToTheAdoptionOfCleaner.pdf>.

[60] Baomoi, Nang luong tai tao: Dung bat nha ngheo choi sang. Available at <www.baomoi.com/Info/Nang-luong-tai-tao-Dung-bat-nha-ngheo-choi-sang/136/3988561.epi>.

12.7 Conclusion

Vietnam has extensive resources for renewable power development, particularly biomass, solar and wind power. In addition, electricity demand is projected to increase by over 10 per cent a year up to 2020 due to economic growth. Renewable energy has also been identified as a priority for the electrification of off-grid rural communities.

Apart from promotion of renewable energy for off-grid applications, a lack of a clear development policy is, however, hindering progress. There are no specific incentives for renewable power, and according to developers, EVN, the state-owned monopoly, is unwilling to pay more for renewable power. Furthermore, there are no clear policies pertaining to grid connection and planning permission issues, which introduces significant uncertainty into projects.

Chapter 13: Country Comparisons

This report covers a wide variety of countries: from the developed OECD member states of Australia, Japan, and South Korea, and, although not an OECD member, Taiwan; to the developing countries of China, India, Indonesia, Malaysia, the Philippines, Thailand and Vietnam. This diversity in some cases makes it difficult to directly compare countries and sectors. While all the countries have some similar drivers for increasing renewable energy deployment, namely enhancing energy security and reducing greenhouse gas emissions, developing countries also have other concerns, such as the need to quickly build new generating capacity to meet high growth in demand and to ensure that all citizens have access to energy. This does not imply that it is possible to generalise that all the developed countries and all the developing countries have similar risks and opportunities. Instead, each country's renewable energy sector has its own unique mix of opportunities and risks, as shown in the results below.

It is important to note that the indices produced in this report are not intended to provide a complete means to assess investment suitability through an aggregated comparison of overall opportunities and risks. Rather, they provide for a comparative analysis of the characteristics of the renewable electricity sectors in a sample of 11 different countries in the Asia-Pacific region. This enables a greater depth of understanding of the differences and commonalities in the renewable electricity sectors covered, and also highlights certain exceptional characteristics in individual countries.

Opportunities Indices

- **Incentive Opportunities Index**: How attractive to investors and developers are the government's incentives for renewable power development?
- **Power Market Opportunities Index**: How much demand is there or will there be for renewable power?
- **Technology Opportunities Index**: Which renewable power technologies are already established and which are emerging in the market concerned?

Table 13.1: Total incentive and power market opportunities indices

2010-11	Australia	China	India	Indonesia	Japan	Malaysia	Philippines	South Korea	Taiwan	Thailand	Vietnam
Incentive Opportunity Index	2	5	5	0	2	1	0	5	5	4	0
Power Market Opportunities Index	3	4	4	4	2	3	4	4	4	4	3
TOTAL	5	9	9	4	4	4	4	9	9	8	3

Figure 13.1: Incentive and power market opportunities indices

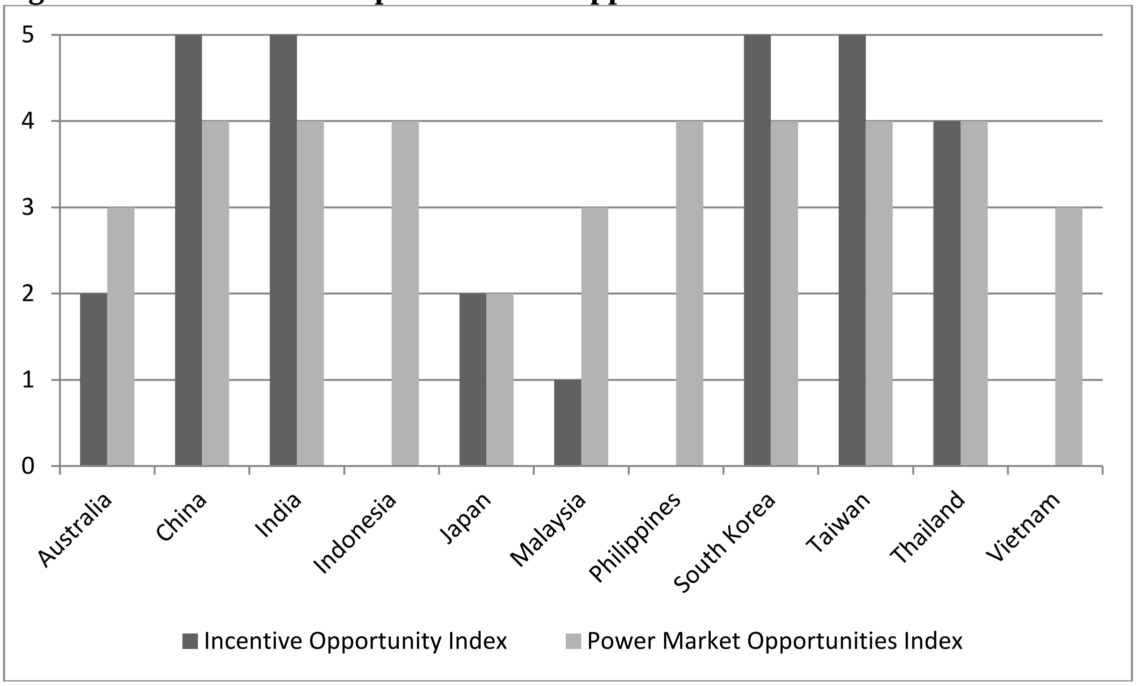
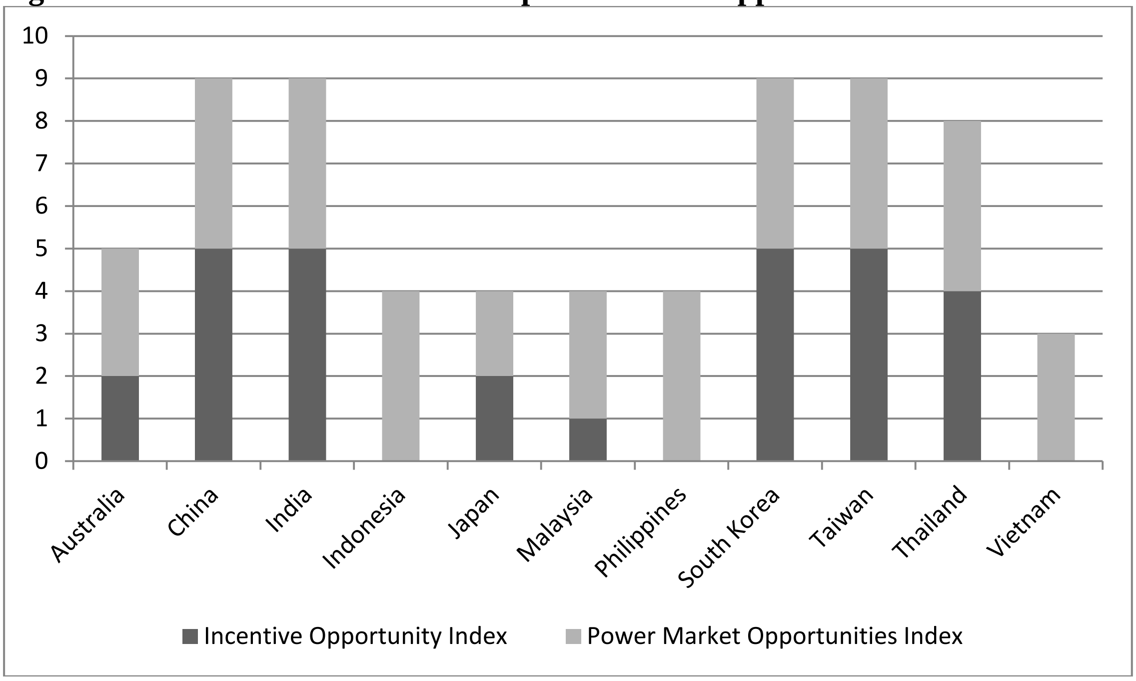


Figure 13.2: Combined incentive and power market opportunities indices



1. The opportunity indices, while measuring the comparative value of incentive systems and power markets, do not make or imply any recommendations or draw any conclusions regarding the likely profitability of renewable electricity generation projects in these countries. However, the greatest opportunities provided by power markets and government incentive systems are in China, India, South Korea, and Taiwan, followed by Thailand. In these countries both the incentives employed and the power markets provide the best opportunities for renewable electricity investment.

2. On average, the Southeast Asian states of Indonesia, Malaysia, the Philippines and Vietnam offer fewer opportunities as a result of unattractive incentives.

3. Australia and Japan offer fewer opportunities due to a lower requirement for new generating capacity as the growth in power demand is low.

4. Apart from in Australia and Japan, there will be a need for large investment in new generating capacity in the countries studied due to rapidly increasing energy demand stemming from industrialisation and increasing standards of living.

5. If the proposed feed-in tariff systems in Malaysia and the Philippines are adopted as scheduled, a much faster growth in renewable power deployment could be expected in these countries.

6. With the exception of large hydro, geothermal, biomass, biogas, and small hydro are the technologies for renewable electricity generation that are the most established in the region. In the developing countries, biomass and small hydro tend to be used for rural electrification projects. Onshore wind power is rapidly increasing and should become more widespread in the coming years.

7. Solar PV is the renewable electricity generation technology that could be expected to have the fastest growth in deployment in coming years due to high resource levels throughout the region. Growth in offshore wind power should be limited, apart from China, where the region's first offshore wind farm was commissioned in 2010, and potentially South Korea and Taiwan.

8. The development of marine energy will be limited to Japan, Australia, Taiwan and China for the near future due to the high costs in developing pilot projects.

Risk Indices

- **Political Will Risk Index**: How committed is the government in question to meeting its pledged targets on renewable energy (RE) and electricity and how stable is renewable power development on the political agenda?
- **Grid Connection Risk Index**: How serious is the problem of grid connection for renewable power installations?
- **Planning Permission Risk Index**: How serious is the problem of securing planning permission for renewable power installations?

Table 13.2: Total political will, grid connection and planning permission risk indices

2010-11	Australia	China	India	Indonesia	Japan	Malaysia	Philippines	South Korea	Taiwan	Thailand	Vietnam
Political Will Risk Index	1	1	1	1	3	0	1	1	1	2	1
Grid Connection Risk Index	3	2	1	3	2	4	2	2	3	3	4
Planning Permission Risk Index	0	1	1	3	1	1	2	0	2	2	2
TOTAL	4	4	3	7	6	5	5	3	6	7	7

Figure 13.3: Political will, grid connection and planning permission risk indices

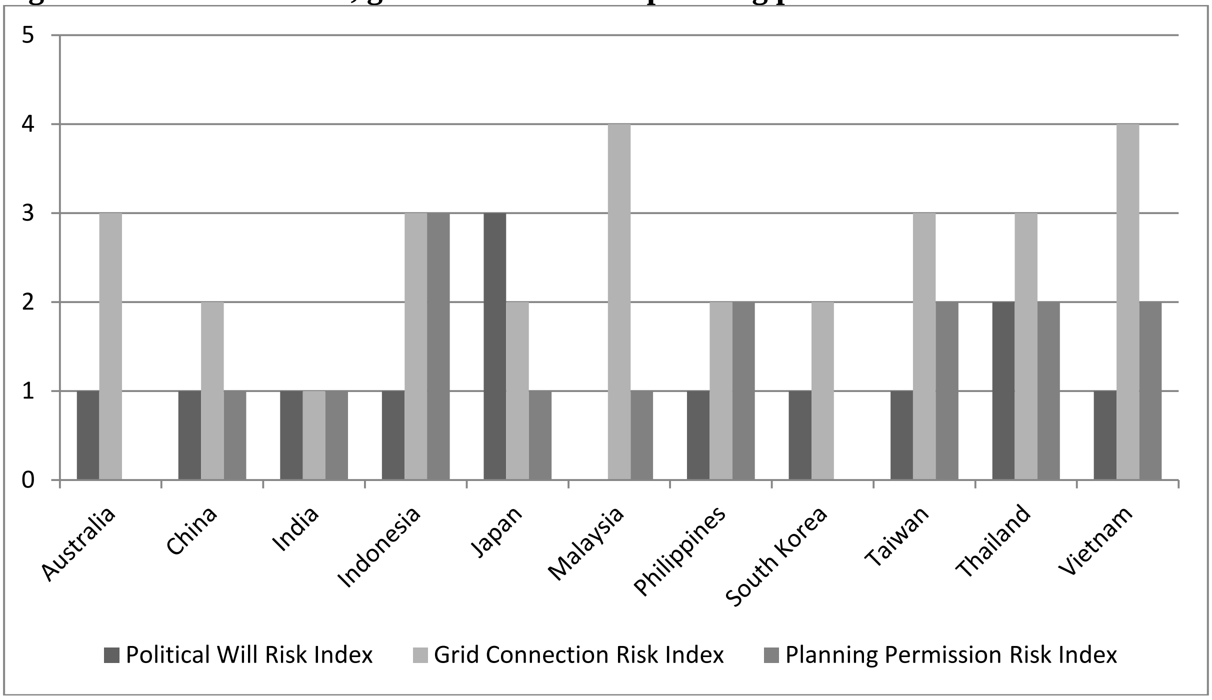
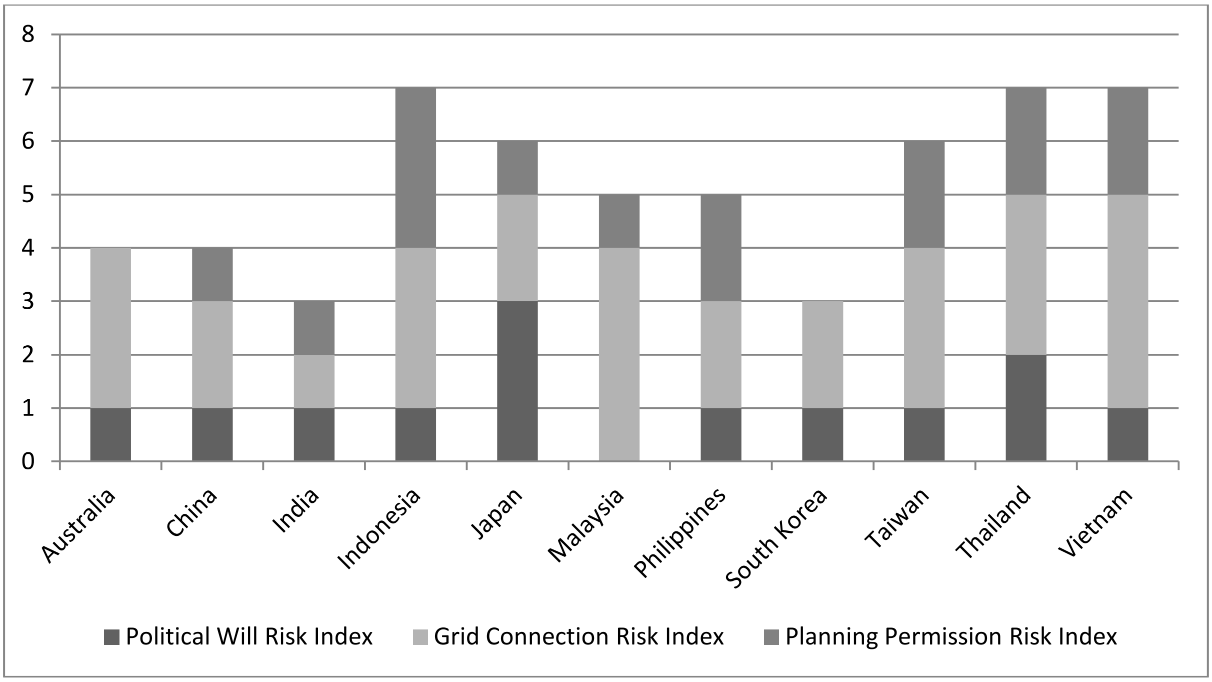


Figure 13.4: Combined political will, grid connection and planning permission risk indices



1. The lowest risks to renewable electricity investment are in India and South Korea. Australia and China follow with only slightly higher risk levels.

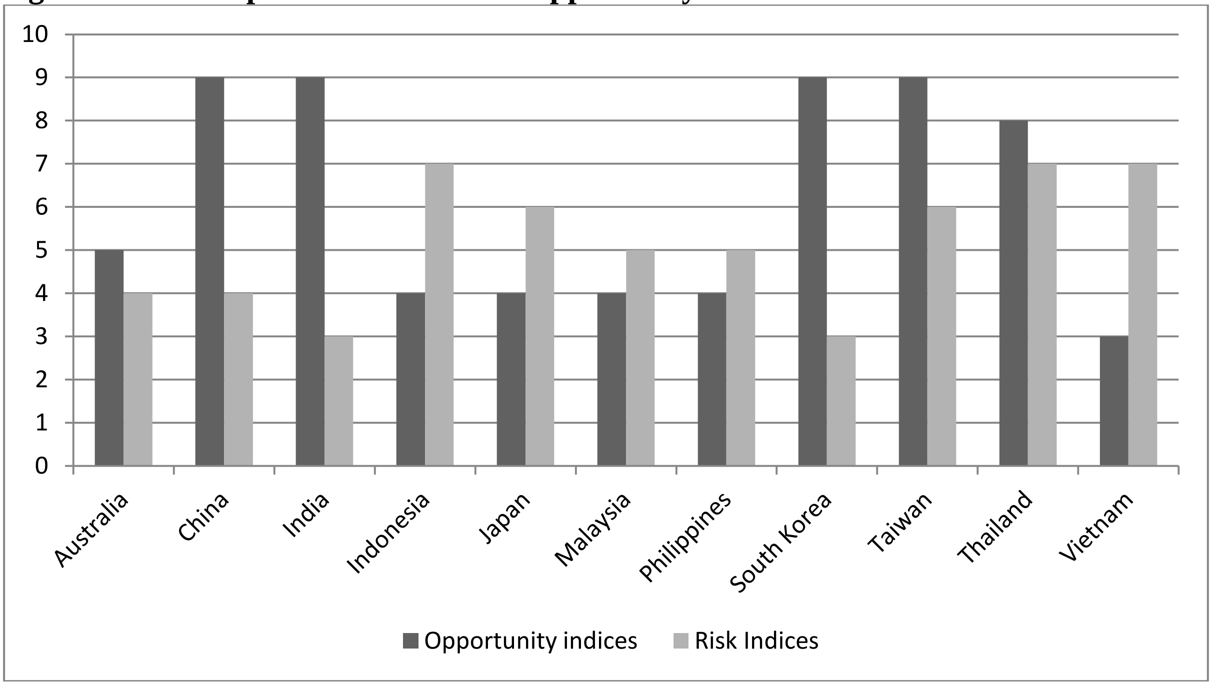
2. Risk levels in Indonesia, Thailand and Vietnam are relatively high, particularly surrounding grid connections and planning permission.

3. Political risk levels in Japan are high due to the large government debt creating the possibility that incentives may be curtailed.

4. Apart from Japan, political risks are low in all the countries studied, with risks surrounding grid connection the largest barrier to increased deployment, especially in Southeast Asia. However, in Southeast Asia, the majority of renewable power projects are for off-grid rural electrification.

Comparison of Opportunities and Risks

Figure 13.5: Comparison of combined opportunity and risk indices



1. When the opportunity and risk indices are evaluated together, it is clear that China, India, and South Korea should see a large increase in the deployment of renewable energy as they have a combination of relatively high opportunities and low risks.

2. Despite having a relatively low opportunities score, the low level of risks in Australia should also ensure increased renewable energy deployment in that country.

3. If improved incentive schemes were available in Japan an increase in deployment could be expected. Malaysia and the Philippines have already proposed introducing a feed-in tariff schemes in the near future. If these schemes are properly implemented, the renewable power sector could also be expected to increase in these two countries.

Chapter 14: Glossary

Anaerobic digestion for biogas	The process of the breakdown of biodegradable material in the absence of oxygen to produce biogas suitable for use in energy production. Generally used on wastewater sludge and organic wastes.
Annex I countries	Countries identified under the Kyoto Protocol as developed countries and therefore have binding greenhouse gas emissions reduction targets. In general most of the OECD countries are also Annex I countries.
Baseload	The minimum level of power demand on a system during 24 hours. This demand is met by "base-load plants" that can supply power at a steady rate. These often run on nuclear, hydro, coal, etc.
Baseline scenario	The baseline scenario is a "business-as-usual" scenario in which current trends are assumed to continue into the future.
Biogas	Any form of methane gas produced from organic sources. Biogas generally comes from sewage or landfill sites.
Biomass	A generic term for all organic material used as an energy source. Biomass includes 1) solid biomass, such as wood or municipal waste (biowaste), and 2) biogas.
Capacity	The rated output of a power generation unit.
Capacity charge	A charge set by the grid operator to use the power grid for power transmission.
Certified Emissions Reduction (CER)	See *Clean Development Mechanism*.
Clean Development Mechanism (CDM)	An instrument of the Kyoto Protocol to the UN's Framework Convention on Climate Change (UNFCCC). Under the CDM, companies can earn Certified Emissions Reduction (CER) credits in developing countries by developing renewable energy projects (among others). The CER can then be traded or sold to reduce their carbon emissions in the more developed countries that have binding emissions reduction targets (so-called Annex I countries). CERs can be used under the European Union's Emissions Trading Scheme (ETS).
Co-firing with biomass	The combustion of biomass and fossil fuels (generally coal or natural gas) together. This is less polluting than the use of fossil fuels alone. It has the advantage that it can be done in conventional power plants without large-scale redevelopment.
Cogeneration plant	See *combined heat and power plant*.
Combined cycle power plants	Power plants with gas and steam turbine generators. The waste heat from gas turbine generators is used to produce steam for steam turbine generators.
Combined heat and power plant (CHP)	A power plant that generates both electricity and heat. CHP plants may use renewable energy sources such as biomass. Renewable electricity generated at CHP plants is included in the statistics of renewable electricity generation. Sometimes referred to as a *cogeneration plant*.
Concentrated solar PV	Use of mirrors or lenses to focus the sunlight onto a PV array. This can be a more efficient way to use solar PV panels.

Concentrated solar-thermal plant	An electricity-generating plant that uses mirrors or lenses to focus the heat from sunlight onto a small area to generate electricity.
Copenhagen Accord	An Accord signed in Copenhagen in December 2009 under the auspices of the UN Framework Convention on Climate Change. Each state is compelled (although not required) to set emissions reduction targets.
Distribution system operator (DSO)	The DSO manages the low- and medium-voltage power network that transmits and distributes electricity from the high-voltage grid run by the transmission system operator to customers. Smaller generators can be directly connected to the low- or medium-voltage grid.
Emerging technology	Emerging technologies are those renewable electricity generating technologies that are still emerging in the electricity market concerned. They often include offshore wind, solar PV, concentrated solar-thermal, wave and tidal power, and advanced forms of biomass such as anaerobic digestion for biogas. As they are still far from being competitive with traditional generation technologies, they require additional support to develop. See also *established technology*.
Established technology	Established technologies are those renewable electricity-generating technologies that have become common in the electricity market concerned. They often include onshore wind, hydro (large and small), geothermal, landfill gas, sewage gas and some forms of biomass. See also *emerging technology*.
Feed-in tariff (FIT)	A primary support mechanism used by governments to promote renewable electricity development. It generally offers price guarantees for a set period of time and a system of obligatory purchase of all power by a network operator. See *premium* and *tradable green certificates* for comparison.
Final energy consumption	Energy supplied to the final consumer's door for all uses, including industry, transport, households, services, agriculture, forestry, and fisheries. In the electricity sector this includes the losses in electricity production and distribution. Generally measured in tonnes of oil equivalent (toe). See also *primary energy consumption*.
Fixed premium	A fixed premium, sometimes called a Green Bonus, is a set amount that renewable electricity generators receive in addition to the sales price (or market price) of electricity. Therefore, the net generation compensation is the sales or market price of electricity plus this fixed premium. See *variable premium* for comparison.
Generation	In this report, it means production of electricity.
Generating capacity	See *capacity*.
Generation compensation	The total amount of compensation that a generator receives for their power output. In this report, this includes, where appropriate, the market price of electricity plus operating incentives.
Greenhouse gases (GHG)	Those gases that contribute to global warming through the greenhouse effect. These include carbon dioxide, methane, nitrous oxide, etc.
Grid connection charges	This covers all the charges for a generator to be connected to the grid and to use the grid. These include connection and entry charges but not grid usage charges. Grid connection charges and procedures vary greatly among countries and are highlighted in the report when they affect renewable electricity development.
Hydro (electric) power plants	Any power plant that uses the flow of water to generate electricity. There are "large hydro" (or simply "hydro"), "small hydro" and "mini-hydro". Although there are no official definitions, small hydro and mini-hydro are generally defined as having a capacity under 10 MW and 1 MW, respectively.

Incentives	Government programmes to promote the development of renewable energy. See also *primary support mechanism*.
Installed capacity	Power generating capacity measured in Watts. See also *generation* and *peak demand*.
Interconnector	A physical connection between separate grids (in general between different countries) to allow for the import and export of electricity.
Levelised generation cost	The average generation cost of a power station. Generally established using a levelised lifetime cost methodology which factors in the discounted investment, operation and maintenance and fuel expenditures for a year, divided by the electricity generated during the same period, similarly discounted. Transmission and grid charges are not included. In this report, the levelised generation costs are sourced from the IEA, unless otherwise specified.[a]
Load hours	The amount of hours for which a generator delivered electricity. Full load hours refers to the amount of time for which a generator is delivering its fullest possible load of electricity. For example, a 1 MW wind turbine that generates 1 MWh of electricity has 1 full load hour.
Lignite	The lowest grade of coal, often referred to as brown coal. It tends to be more polluting than black or hard coal.
Mineral oils	Fossil-fuel liquids, such as petrol, diesel, heating oil and kerosene.
Microgeneration	Small-scale electricity generation, usually for private use, although if surplus electricity is created it can be sold to the network.
NIMBY	“Not in My Back Yard”—in this report, the desire of the local population not to have any power generation installations in their community.
Obligatory purchase	In this report, the policy that a network operator or utility has to purchase all the output of a renewable electricity generating installation regardless of demand. Generally found with a feed-in tariff incentive.
Off-peak hours	The period of day when demand for power is at the lowest (generally at night).
Peak demand	The highest power demand on a system. In this report, the highest demand in a year.
Peak hours	The period of day when demand for power is the highest.
Premium	An operating incentive where renewable electricity generators receive a government-set supplement in addition to the sales or market price of electricity per unit of output sold. Unlike the FIT there is no system of obligatory purchase. There are generally two types: *fixed* and *variable premiums*.
Primary energy consumption	The quantity of all energy consumed within the borders, including imports. It is a measure of all energy sources before they are converted into energy. Generally measured in tonnes of oil equivalent (toe).
Primary support mechanism	The main incentive programme of the government to promote renewable electricity development, generally including *feed-in tariffs (FITs)*, *premiums* and *tradable green certificates*.

Pumped storage hydro (electric) power plants	These plants are for peak load use. Water which is pumped up to an upper reservoir during the off-peak hours and is discharged during the peak hours to generate electricity.
Renewable electricity	Electricity generated from a renewable energy source.
Renewable energy	Renewable energy is any form of energy (electricity, heat, transportation fuels, etc.) produced by renewable energy sources such as hydro, wind, biomass, wave and tidal, solar, and geothermal.
Shallow costs for grid connection	The developer is only charged for constructing a line to the first grid connection point and not for the grid enhancement that may be necessary for the connection. See also *deep costs for grid connection*.
Solid biomass	Solid organic material that can be used for energy production, generally realised through combustion. For example, wood waste.
Solid fuels	Generally forms of coal or their derivatives.
Solar PV (photovoltaic)	The direct conversion of sunlight into electricity.
Suppliers	Those who sell electricity to end users.
Thermal power plant	Power plants that generate electricity by combustion. They include gas-, coal- and oil-fired power plants. National statistics sometimes include plants of solid biomass and biogas combustion and the co-firing of biomass and fossil fuels, as well as combined heat and power plants. If this is the case, a note is made in the report.
Tradable green certificates	A primary support mechanism in which renewable electricity generators are awarded certificates for their power generation from renewable sources. Suppliers or distributors have a quota obligation for renewable energy and need to buy the certificates to prove they have met their quota.
Transmission system operator (TSO)	The high-voltage electricity grid operator. The high-voltage grid transmits electricity generally between generators and distributors over long distances.
Unbundling	In this report, it specifically refers to the structural separation of the operation of the power transmission networks from the generation and supply of power. There are various levels of unbundling, which include: • Functional unbundling: The transmission system operator is owned by a larger conglomerate (sometimes state owned), but is housed in an independent business unit. • Legal unbundling: The transmission and distribution companies might remain majority-owned by a larger power conglomerate, but are housed in independent companies. • Ownership unbundling: Separate ownership of the network operators from activities related to generation or supply of electricity. Minority ownership may be retained by larger power conglomerates.
Variable premium	A premium system in which the generation compensation is capped at a set amount. The variable premium fills in the gap between the market price of electricity and the set amount and hence the variable premium will change with the market price of electricity.
Wholesale electricity market	The purchase and sale of electricity from generators to resellers on the open market.

Notes: [a] For more information, IEA, Projected Costs of Generating Electricity, 2010. IEA: Paris, 2010.
Sources: For a detailed glossary see the Energy Information Agency, Glossary of Electricity Terms. Available at <www.eia.doe.gov/cneaf/electricity/epav1/glossary.html>.