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Renewable Energy: A Comprehensive Guide to Regulatory and Contractual Issues when Trading RECs and Other Green Rights

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SUMMARY

The introduction of the Commonwealth renewable energy legislation in December 2000 and other greenhouse measures has resulted in the development of a number of large renewable energy projects in Australia. Over the last two years, industry participants have learned a lot about the unique legal issues associated with renewable energy projects and some of the unique commercial hurdles that need to be addressed in structuring and documenting such projects. There has also been a lot of debate as to the correct form of contract to use to buy and sell Renewable Energy Certificates (RECs) and other Green Rights. Finally, there have been some teething problems with the Commonwealth legislation, which have already resulted in some amendments, with more proposed.

This paper firstly looks at the current status of the Commonwealth renewable energy legislation (which provides for the creation and transfer of RECs) and changes that have had to be made to that legislation. It then briefly considers the various ways that RECs, other Green Rights and the associated electricity can be traded – that is, a sale of RECs by themselves or in conjunction with other Green Rights and either the associated electricity or an electricity derivative transaction. This leads to a consideration of the other greenhouse schemes which operate in conjunction with the Commonwealth scheme and which overlap with that scheme. These are the NSW Greenhouse Gas Abatement Scheme (which provides for the creation and transfer of Abatement Certificates), the Green Power Accreditation Program and the Queensland 13% Gas Scheme (which provides for the creation and transfer of Gas Electricity Certificates (GECs)).

This paper then considers those requirements of the National Electricity Code (Code) and the Corporations Act 2001 (Cth) (Corporations Act) which impact on the above transactions. These includes registration issues under the Code, the need

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in some cases to obtain an Australian Financial Services Licence (AFS Licence) and insider trading issues.

This paper then discusses the standard requirements of a contract to sell RECs by themselves or in conjunction with other Green Rights and either the associated electricity or an electricity derivative transaction – a significant issue being the allocation of risks associated with a fluctuating quantity of electricity and Green Rights. This paper also addresses one issue of continued debate by considering the advantages and disadvantages of using an ISDA contract as opposed to a non-ISDA contract. The choice between these types of contract raises a number of issues and depends on the type of transaction (be it a sale of electricity, an electricity derivative or a sale of Green Rights), the consequences that the parties are trying to achieve (particularly in relation to their respective liabilities should the transaction terminate early) and generally how far the terms of the transaction will deviate from the standard terms in the ISDA documentation.

THE COMMONWEALTH GOVERNMENT'S MRET SCHEME (RECs)

Overview of the Scheme

The Commonwealth Government's MRET Scheme supports the implementation of its "Mandatory Renewable Energy Target" (MRET). That target is to achieve, by 2010, the generation from renewable energy sources of 9,500 MWh per annum. This amount corresponds to 2% of the previously forecasted electricity consumption for that year.[1]

The scheme creates a form of transferable intangible property known as "Renewable Energy Certificates" (RECs) and other Green Rights.[2] RECs can be created by the operators of power stations which generate electricity from renewable energy sources above a given baseline. The RECs are able to be traded independently of the electricity. The scheme creates a demand for RECs by effectively requiring certain wholesale purchasers of electricity to purchase and surrender an amount of RECs which corresponds to the amount of electricity that they purchase or to pay a charge for any shortfall. By enabling generators to create and sell RECs in addition to the generated electricity and by creating among wholesale electricity purchasers a demand for RECs, the scheme attempts to pass the cost of funding this additional renewable energy generation onto those wholesale purchasers.

1 Subsequent forecasts have estimated that electricity consumption in 2010 is likely to be higher than previously estimated with the result that 9,500 MWh will be less than 2% of annual electricity consumption.

2 The expression "Green Rights" is used in this paper to refer to all certificates, credits and other rights or benefits which arise as a result of the generation of electricity from a "renewable" or "green" fuel source. The expression therefore includes RECs, NSW Abatement Certificates (that is, NGACs and LUACs), Green Power and GECs. Each of these expressions is defined below in this paper.

More specific details of the scheme are contained in the paragraphs below.

Duration of the Scheme

The scheme provides for the creation of RECs in relation to electricity generated between 1 April 2001 and 31 December 2020 and for the surrender of RECs or the payment of the "renewable energy shortfall charge" in relation to electricity consumed in that same period.

Overview of the Legislation

The scheme has been put in place by the following legislation:

1. The *Renewable Energy (Electricity) Act* 2000 (Cth) (REC Act)
2. The *Renewable Energy (Electricity) (Charge) Act* 2000 (Cth) (REC Charge Act)[3]
3. The *Renewable Energy (Electricity) Regulations* 2001 (Cth) (REC Regulations).

The majority of the framework of the scheme is in the REC Act. This outlines the broad principles for eligibility to create RECs and liability to acquire RECs or pay the renewable energy shortfall charge. The REC Act also specifies the renewable energy targets which must be achieved over the period 2001 to 2020. The REC Charge Act specifies the amount of the renewable energy shortfall charge. The REC Regulations contain more detailed rules on a number of issues, including additional eligibility criteria for renewable energy sources, accreditation of power stations and deemed renewable energy certificate amounts for solar water heaters and some specified small generators.

Creating the Demand

The REC Act creates a demand for RECs by effectively requiring "liable entities" to acquire RECs or pay the renewable energy shortfall charge.

Who is liable?

A "liable entity" is a person who, during a year, makes a "relevant acquisition" of electricity (s 35 REC Act). There are two types of relevant acquisitions of electricity, being a "wholesale acquisition" and a "notional wholesale acquisition" (s 31(1) REC Act).

[3] This Act was amended by the *Renewable Energy (Electricity) (Charge) Amendment Act* 2000 (Cth). The amending Act amended the original Act with effect from the date of commencement of the original Act. The amending Act inserted a new section 6 providing that the rate of the renewable energy shortfall charge is $40/MWh.

The following are "wholesale acquisitions" of electricity:

(a) all acquisitions from National Electricity Market Management Company Limited (NEMMCO) in the National Electricity Market (NEM);[4] and

(b) all acquisitions from the generator of the electricity by a purchaser who is registered under the National Electricity Code (Code) (s 32 REC Act).

There are two situations in which a "notional wholesale acquisition" of electricity takes place.

The first situation is where an end user of the electricity who is not registered under the Code acquires the electricity from the generator. In this situation, the generator is taken to be two persons (being the "notional generator" and the "notional wholesaler") and a notional wholesale acquisition is taken to have occurred between the notional generator and the notional wholesaler at the time that the end user acquired the electricity from the generator (s 33(2) REC Act). However, that acquisition will not be a notional wholesale acquisition if the generator previously sold it to another person (including NEMMCO) before buying it back and on-selling it to the end user – in which case a relevant acquisition would have already occurred in relation to the earlier sale (s 33(2A) REC Act).[5]

The second situation (which involves "self-generation") is where the end user generated the electricity and neither of the following conditions are satisfied:

(a) the point at which the electricity is generated is less than 1 km from the point at which the electricity is used;

(b) the electricity is transmitted or distributed between the point of generation and the point of use and the line on which the electricity is transmitted or distributed is used solely for the transmission or distribution of electricity between those two points.

In this situation, the generator is taken to be two persons (being the "notional generator" and the "notional wholesaler") and a notional wholesale acquisition is taken to have occurred between the notional generator and the notional wholesaler at the time that the electricity is used (s 33(3) REC Act).

Despite the above, the following acquisitions are not relevant acquisitions:

(a) an acquisition where the electricity is delivered on a grid that has a capacity that is less than 100 MW and that is not, directly or indirectly, connected to a grid that has a capacity of 100 MW or more;

(b) a "self-generation" scenario where the end user generates the electricity and either:

  (i) the point at which the electricity is generated is less than 1 km from the point at which the electricity is used; or

4 As will be discussed below, NEMMCO operates and administers the National Electricity Market under the Code.

5 This section will be deleted when the *Renewable Energy (Electricity) Amendment Bill* 2002 (Cth) comes into effect. A new s 32(3) will be inserted to address the potential overlap between ss 32 and 33 – see below.

(ii) the electricity is transmitted or distributed between the point of generation and the point of use and the line on which the electricity is transmitted or distributed is used solely for the transmission or distribution of electricity between those two points; and

(c) an acquisition where the electricity is later acquired by NEMMCO (s 31(2) REC Act).

How is liability calculated?

In essence, a liable entity can calculate the number of RECs that it needs to acquire or the renewable energy shortfall charge that it needs to pay for a given calendar year by multiplying the amount of electricity (in MWh) acquired by it under relevant acquisitions in that year by the "renewable power percentage" (defined below) for that year. For each resulting MWh, the liable entity must either purchase and surrender a REC or pay the renewable energy shortfall charge.[6]

This is the effect of s 38 of the REC Act which effectively provides that a liable entity's "renewable energy certificate shortfall" for a given calendar year is calculated as follows:

(a) work out the total amount (in MWh) of electricity acquired by the liable entity during the year under relevant acquisitions;

(b) multiply the above result by the renewable power percentage for the year and round the result to the nearest MWh. Then add any carried forward shortfall from the previous year or subtract any carried forward surplus from the previous year. The result is the liable entity's "required renewable energy" for the year;

(c) subtract from the above result the total value (in MWh) of RECs surrendered by the liable entity to the Regulator for that year; and

(d) if the result is greater than zero then the liable entity has a "renewable energy certificate shortfall" for the year equal to that amount. If the result is zero then the liable entity does not have a renewable energy certificate shortfall for the year. If the result is less than zero then the liable entity has a carried forward surplus for the year.

Subject to one qualification, if a liable entity has a renewable energy certificate shortfall for a given year then the renewable energy shortfall charge is payable in respect of that shortfall. The qualification is that no renewable energy shortfall charge is payable for a year if the renewable energy certificate shortfall is less than 10% of the liable entity's required renewable energy for the year. In such a case, the renewable energy certificate shortfall is carried forward to the next year (s 36 REC Act).

[6] It is not an offence not to purchase and surrender a REC. It just leads to a consequence that a liability to pay the renewable energy shortfall charge arises.

What affects the demand for and the price of RECs?

The demand for RECs is a function of the value of the renewable power percentage. The price that liable entities will be prepared to pay for RECs is a function of the rate of the renewable energy shortfall charge.

The renewable power percentage for a given year is the percentage specified in the REC Regulations or, if the REC Regulations do not specify a percentage, the percentage calculated in accordance with s 39 of the REC Act. The renewable power percentage prescribed by the REC Regulations for the years to date has been 0.24% for 2001, 0.62% for 2002 and 0.88% for 2003.[7]

The formula in s 39 of the REC Act provides for the renewable power percentage for a given year to be calculated by multiplying the renewable power percentage for the previous year by the required GWh of renewable source electricity for the given year divided by the required GWh of renewable source electricity for the previous year.

The required GWh for all years covered by the scheme is specified in s 40 of the REC Act. Commencing with 300 GWh for 2001, it rises each year to reach 9,500 GWh in 2010 and remains at that level up to and including 2020 (after which the scheme ends).

The amount of the renewable energy shortfall charge payable by a liable entity is calculated by multiplying the liable entity's renewable energy certificate shortfall by the "rate of charge" (s 37 REC Act). The rate of charge is specified in s 6 of the REC Charge Act to be $40.

Note that the renewable energy shortfall charge is not tax deductible whereas the cost of purchasing RECs is tax deductible. Therefore, assuming a corporate tax rate of 30%, a renewable energy shortfall charge of $40 corresponds to a maximum purchase price for RECs of $57.14 (above which it would be cheaper to pay the renewable energy shortfall charge).[8]

Energy acquisition statement

A liable entity who acquired electricity under a relevant acquisition during a calendar year is required to lodge an "energy acquisition statement" for the year on or before 14 February in the following year or such later date as is allowed by the Regulator (s 44 REC Act). That statement must set out (among other things) the amount of electricity acquired under relevant acquisitions, the value (in MWh) of RECs surrendered for the year and any carried forward shortfall or carried

7 See s 39 REC Act. Section 39(3) specifies various matters to be taken into consideration when determining the value of the renewable power percentage to be prescribed by regulation. See also cl 23 REC Regulations.

8 The maximum price which a liable entity would be prepared to pay for a REC, given a renewable energy shortfall charge of $40 and assuming a corporate tax rate of 30%, can be calculated by dividing the value of the charge by (1 minus the tax rate) – that is, $40 / (1 – 0.3) = $57.14.

forward surplus for the previous year. The statement must also be accompanied by details of all RECs being surrendered for that year.

Surrender of RECs

A REC cannot be surrendered unless it is valid, it was created before the end of the year to which the energy acquisition statement relates and the liable entity is recorded in the Register of Certificates as the owner of the REC at the time that the statement is lodged (s 45 REC Act).

The significance for a purchaser of RECs is that for RECs to be of any value in reducing the purchaser's liability to pay the renewable energy shortfall charge for a given year, the RECs must be created and registered in the name of the operator and then transferred and registered in the name of the purchaser before 14 February in the following year. This needs to be reflected in the delivery date under any contract to acquire RECs.

Where a REC is surrendered, the REC ceases to be valid (s 29(1) REC Act).

Renewable energy shortfall statement

A liable entity that has a renewable energy certificate shortfall for a calendar year is required to lodge a "renewable energy shortfall statement" for the year on or before 14 February in the following year or such later date as is allowed by the Regulator. That statement must set out the liable entity's renewable energy certificate shortfall for the year, any carried forward shortfall or carried forward surplus for the previous year and the amount of the renewable energy shortfall charge for the year (among other things) (s 46 REC Act).

A renewable energy shortfall statement has the effect of an assessment of the liable entity's renewable energy certificate shortfall and renewable energy shortfall charge for the year (s 47 REC Act). Assuming that the liable entity lodges its renewable energy shortfall statement for a given year on or before 14 February in the following year, the renewable energy shortfall charge for that year is payable on 14 February (s 67 REC Act).

Creating the Supply

Registration of persons and accreditation of power stations

Before RECs can be created in respect of the electricity generated by a given power station, it is necessary for:

(a) the owner of the power station to become a registered person under the REC Act;

(b) the above owner (once registered) to arrange for the power station to be accredited as an accredited power station under the REC Act (as only an owner who is a registered person can apply for this accreditation); and

(c) the operator of the power station to become a registered person under the REC Act (as only a registered operator of an accredited power station is able to create RECs).

The above is a consequence of the various provisions discussed below.

Any person may be registered under the REC Act by making application to the Regulator (ss 9(1) and 10 REC Act). Each registered person is allocated a unique registration number (s 12 REC Act).

A person wishing to apply for the accreditation of an electricity generation system as an accredited power station under the REC Act must be both a registered person under the REC Act and the owner of the system (s 13(1) REC Act). The application must be made to the Regulator and, among other things, must specify the "eligible renewable energy sources" from which power is intended to be generated and the estimated average annual output of each such energy source (s 13(2) REC Act).

An electricity generation system is eligible for accreditation if some or all of the power generated by the system is generated from an eligible renewable energy source and the system satisfies the other requirements in the REC Regulations (s 14(2) Rec Act and cl 4 and Sched 1 REC Regulations).

The effect of s 18(1) of the REC Act is that only the operator of the accredited power station may create RECs and, to do so, the operator must be a registered person.

Each accredited power station has a "1997 eligible renewable power baseline". This is determined by the Regulator in accordance with the guidelines in the REC Regulations (s 14 REC Act and cl 5 and Schedule 3 REC Regulations).

A power station that generates electricity for the first time after 1 January 1997 has a nil baseline (para 1 of Sched 3 REC Regulations). For a power station that generated electricity before 1 January 1997, the general position is that the baseline is the average of the annual electricity generated from eligible renewable energy sources in 1994, 1995 and 1996 (calculated in accordance with para 2 of Sched 3 to the REC Regulations). However, Sched 3 to the REC Regulations provides for other means of calculating the baseline in certain circumstances, which essentially involve power stations with a fluctuating output.

Eligible renewable energy sources

Section 17 of the REC Act defines "eligible renewable energy sources" for the purpose of the creation of RECs. These are hydro, wind, solar, bagasse co-generation, black liquor, wood waste, energy crops, crop waste, food and agricultural wet waste, landfill gas, municipal solid waste combustion, sewage gas, geothermal-aquifer, tidal, photovoltaic and photovoltaic Renewable Stand Alone Power Supply systems, wind and wind hybrid Renewable Stand Alone Power Supply systems, micro hydro Renewable Stand Alone Power Supply systems, solar hot water, co-firing, wave, ocean, fuel cells and hot dry rocks (s 17(1) REC Act). "Eligible renewable energy sources" does not include fossil fuels and waste products derived from fossil fuels (s 17(2) REC Act).

Creation of RECs by the operator

A registered person may create a REC for each whole MWh of electricity generated by an accredited power station that the person operates during a calendar year that is in excess of the power station's 1997 eligible renewable power baseline (s 18(1) REC Act). For the purpose of determining the amount of electricity generated, only electricity generated using eligible renewable energy sources can be counted (s 18(4) REC Act). The REC can be created immediately after the generation of the relevant MWh of electricity (s 19 REC Act).

A registered person who generates electricity during a given calendar year must give an electricity generation return for the year to the Regulator before 14 February in the following year. That return must include details of (among other things) the amount of electricity generated during the year, the amount o b f that electricity that was generated using eligible renewable energy sources and the number of RECs created in respect of that electricity (s 20(2) REC Act). It is an offence to create a REC without being entitled to do so (s 24 REC Act).

Nature of RECs and registration

RECs must be created in an electronic form approved in writing by the Regulator (s 25(1) REC Act). Each REC is to contain a unique identification code. This is to consist of the following numbers in the following order:

(a) the registered person's registration number;
(b) the power station's identification code;
(c) the year of generation; and
(d) a number in an unbroken sequence, that is used for all RECs issued in respect of electricity generated by the power station in that year, that starts at 1 and has increments of 1 (s 25(2) REC Act)

Each REC is also to contain the electronic signature of the person who created the REC, the date on which the electricity in relation to which the REC was created was generated and the date on which the REC was created (s 25(2) REC Act).

The Regulator must be advised of the creation of a REC. Upon receiving that notification, the Regulator must determine whether the REC is eligible for registration. If it is eligible for registration, the Regulator must then enter the REC in the Register of Certificates and record the person who created the REC as its owner. A REC is not valid until it has been registered by the Regulator (s 26 REC Act).

Transfer issues

Registered RECs may be transferred to any person (s 27 REC Act). The Regulator must be notified of the transfer of the REC (s 28(1) REC Act). That notification must be by electronic transmission in a manner determined by the Regulator (s 28(2) REC Act). When the Regulator is notified, the Regulator must alter the Register of Certificates to show the transferee as the owner of the REC (s 28(3) REC Act).

AMENDMENTS TO THE MRET SCHEME

Changes to the REC Regulations

The REC Regulations have been amended with effect from the following dates by the following regulations:

(a) on 23 August 2001 by the *Renewable Energy (Electricity) Amendment Regulations* 2001 (No 1) (Cth) (Reg 1/01);
(b) on 15 March 2002 by the *Renewable Energy (Electricity) Amendment Regulations* 2002 (No 1) (Cth) (Reg 1/02);
(c) on 4 October 2002 by the *Renewable Energy (Electricity) Amendment Regulations* 2002 (No 2) (Cth) (Reg 2/02);
(d) on 20 December 2002 by the *Renewable Energy (Electricity) Amendment Regulations* 2002 (No 3) (Cth) (Reg 3/02); and
(e) on 29 May 2003 by the *Renewable Energy (Electricity) Amendment Regulations* 2003 (No 1) (Cth) (Reg 1/03).

Changes to be Effected by the Renewable Energy (Electricity) Amendment Bill 2002

The most significant changes to the REC Act to be effected by the *Renewable Energy (Electricity) Amendment Bill* 2002 (Cth) (Bill) are set out in the paragraphs which follow.

Correction of minor deficiencies in the wording of the REC Act

The REC Act contains a number of minor deficiencies in wording which the Bill has attempted to correct. There are also a number of minor deficiencies in the operation of the scheme under the REC Act which the Bill has attempted to correct. The most significant of these are discussed in the paragraphs which follow.

Person who can create RECs

As discussed above, under the REC Act, while any person can register (s 9(1) REC Act):

(a) only the registered person who owns the electricity generation system can apply to the Regulator for the accreditation of that system as an accredited power station (s 13(1) REC Act); and
(b) only the registered person who operates the accredited power station can create RECs in respect of the electricity generated by that power station (s 18(1) REC Act).

This situation has been remedied under the Bill. The new provisions will:

(a) permit any registered person who is an operator (whether alone or together with one or more other persons) or an owner (whether alone or together with one or more other persons) to apply to the Regulator for the accreditation of an electricity generation system as an accredited power station (new s 13(1)). The application must include a written statement from each other person who is an owner or operator of the power station agreeing to the making of the application (new s 13(2)(f));
(b) permit the various owners and operators of an accredited power station to nominate one of those owners and operators to be the "nominated person" for the power station. The nominated person can be changed from time to time (new s 30B and definition of "stakeholder"); and
(c) provide for the nominated person (or if no person is validly nominated, the person who applied for the accreditation of the power station) to be able to create RECs in respect of the electricity generated by the accredited power station (new ss 15A and 18(1) and new definition of "nominated person").

The Bill also includes transitional provisions providing for the Regulator, within 28 days of the above changes commencing, to approve a person as the nominated person for each existing accredited power station (see Item 163 of the Bill).

Eligible renewable energy sources

The Bill amends the definition of "eligible renewable energy sources" in s 17 of the REC Act by:

(a) removing terms that are either redundant or not energy sources (but rather processes or technologies for transforming energy sources into electricity);
(b) reordering the list of energy sources to group similar types of sources together;
(c) regrouping some of the various types of waste in a clearer manner; and
(d) ensuring that materials or waste products that are made from fossil fuels or made from products, by-products or wastes from processing of fossil fuels, including where mixed in with any of the eligible renewable energy sources, are ineligible.

Therefore, the expressions "bagasse co-generation", "crop waste", "food and agricultural wet waste", "municipal solid waste combustion", "tidal", "photovoltaic and photovoltaic Renewable Stand Alone Power Supply systems", "wind and wind hybrid Renewable Stand Alone Power Supply systems", "micro hydro Renewable Stand Alone Power Supply systems", "solar hot water", "co-firing" and "fuel cells" have been deleted from the list of eligible renewable energy sources and the expressions "tide", "agricultural waste", "food waste", "food processing waste", "waste from processing of agricultural products", "bagasse" and "biomass-based components of municipal solid waste" have been inserted. Further, the expression "materials derived from fossil fuels" has been added to the list of exclusions from the definition of eligible renewable energy sources.

Limiting what qualifies as a "new" power station

Under the REC Act, various components of an electricity generation system are determined by the Regulator to be a "power station" for the purposes of the REC Act and then accredited. If the electricity generation system which constitutes a power station is expanded then the new components could potentially be classified as a separate power station and thus accredited separately (with no baseline) thus avoiding the baseline of the previously accredited power station.

The Bill amends s 14 to give the Regulator the power to deny separate accreditation to such new components if the Regulator is satisfied that the new components are effectively an expansion or a modification to an existing accredited power station and should be treated as part of that power station. A new s 30C enables the Regulator to amend the previous determination to include the new components as part of the existing accredited power station. The result of this is that the new components are covered by the baseline of the existing accredited power station.

Extension of time to create RECs

Under the REC Act, for a REC to be able to be created in relation to the electricity generated in a given year, the REC had to be created before 14 February in the year after generation. The Bill amends ss 19 and 20 of the REC Act to enable a REC to be created at any time in the future after the generation of the corresponding electricity.

Time for lodging returns

The Bill amends s 20(1) of the REC Act to enable the Regulator to extend the time for lodging an electricity generation return to a day after 14 February.

RECs to include details of energy source

As discussed above, under s 25(2) of the REC Act, each REC contains information as to the person who created it, the date of generation of the relevant electricity and the date of creation of the REC. The Bill amends s 25(2) to provide that each REC is to also include details of the eligible renewable energy sources used to generate the electricity in relation to which the REC was made.

Extension of grounds for suspension of registration

Under s 30 of the REC Act, the Regulator may suspend a person's registration for up to two years if the person has been convicted of an offence under s 24(3) for creating a REC when not entitled to do so.

The Bill expands the grounds on which the Regulator may suspend a person's registration to include:

(a) where the Regulator believes on reasonable grounds that the person has committed an offence against the REC Act or the regulations – suspension being for a period up to one year (new s 30A(1) and (2)). Note that the offence need not be proven; and

(b) where the registration was obtained improperly (for example, by supplying incorrect information in the application) – there being no limitation on the suspension period (new s 30A(3) and (4)).

The policy rationale is to enable the Regulator to act more proactively to manage the risk of RECs being created contrary to the intent of the REC Act.[9]

Anti-gaming provisions – suspension of accreditation

The Bill inserts a new s 30D into the REC Act to permit the Regulator to suspend the accreditation of power stations where circumstances are consistent with the power stations having been operated together as a part of a gaming arrangement to increase the number of RECs created.

Several criteria need to be satisfied before the Regulator can suspend the accreditation of a power station. These are as follows:

1. The power station is part of a "group of interconnected power stations". Under the new s 30D(3), two or more power stations will form a group of interconnected power stations if each power station is able to generate electricity using a particular supply of an eligible renewable energy source and the amount of electricity generated by each power station during a year using that supply is able to be co-ordinated in order to allow more RECs to be created in respect of the total electricity generated by the power stations during the year using that supply than would otherwise be able to be created.

2. One or more of the power stations (an "excess station") in the group generates electricity during a year that is in excess of its 1997 eligible renewable power baseline for the year. ("Outcome A").

3. One or more of the power stations (a "shortfall station") in the group generates nil electricity during the year or generates electricity during the year that is

[9] See the discussion in para 57 under Item 57 of the Explanatory Memorandum to the *Renewable Energy (Electricity) Amendment Bill* 2000 (Cth).

less than its 1997 eligible renewable power baseline for the year. ("Outcome B").

4. The Regulator is satisfied that more RECs are able to be created in respect of electricity generated during the year by any excess station than would be able to be created if any shortfall station had generated electricity during the year at least equal to its 1997 eligible renewable power baseline for the year (new s 30D(1)).

In deciding whether or not to suspend a power station's accreditation, the Regulator must have regard to any information available to the Regulator that demonstrates that either or both of Outcome A and Outcome B were not the result of a "gaming arrangement" (new s 30D(4)). A "gaming arrangement" is defined in s 30D(6) to be an arrangement to co-ordinate the amount of electricity generated by each power station in the group during the year using the relevant supply of the energy source in order to allow more RECs to be created in respect of the total electricity generated by the power stations in the group during the year using that supply than would otherwise be able to be created.

The policy rationale for such an anti-gaming provision is that gaming has the potential to significantly dilute the effectiveness of the measures in the REC Act to stimulate the growth of the renewable energy industry and abate greenhouse gas emissions.

The significant point to note however, in relation to the above is that there is no requirement for the Regulator to prove that a gaming arrangement has actually occurred. Rather, the lack of evidence that there was no gaming arrangement combined with circumstances which are consistent with the existence of a gaming arrangement will be sufficient.

Other grounds for suspension of accreditation

The Bill also inserts a new s 30E into the REC Act providing other grounds on which the Regulator can suspend the accreditation of a power station. These are:

(a) if an electricity generation return for a given year has not been given to the Regulator in accordance with s 20 of the REC Act (s 30E(1));
(b) if the Regulator believes on reasonable grounds that the power station is being operated in contravention of a law of the Commonwealth, a State or a Territory; and
(c) any other circumstances prescribed by the Regulations.

Variation of 1997 eligible renewable power baselines

The REC Act currently does not permit the 1997 eligible renewable power baseline for an accredited power station to be varied. The Bill addresses this by inserting a new s 30F into the REC Act giving the Regulator the power to make a written determination varying the baseline for an accredited power station in the circumstances prescribed by the regulations.

One such set of circumstances which the regulations may prescribe is a variation to the baseline following an action or policy of the Commonwealth Government which reduces the power station's ability to generate electricity for a sustained period (s 30F(2)).

If an accredited power station's baseline is increased then the increase only commences to apply in the year following the making of the determination (s 30F(4)). If the baseline is decreased then the decrease has effect for the years specified in the determination (s 30F(5)).

Relevant acquisitions – overlap between ss 32 and 33

It is possible under the existing version of the REC Act that more than one transaction in a set of transactions occurring in relation to supply of a particular quantum of electricity could be relevant acquisitions under ss 31 to 34 of the REC Act and that there would be a liability under the REC Act in relation to each of those transactions.

The Bill inserts a new s 32(3) which has the effect that if the set of transactions includes a transaction which is an acquisition from NEMMCO in the NEM then that acquisition will be the only acquisition that gives rise to a liability under the REC Act and other acquisitions in relation to that quantum of electricity will not be relevant acquisitions for the purposes of the REC Act. This amendment takes effect from 1 January 2002.

Information gathering powers

Currently under the REC Act, information gathering powers are restricted to authorised officers of the Office of the Renewable Energy Regulator (ORER) and may only be exercised when premises have been entered (see Pt 11 – being ss 106 to 125 of the REC Act).

The Bill inserts a new Pt 11A (consisting of ss 125A to 125F) which provides ORER with additional information gathering powers.

Section 125A gives ORER the right to require a person to provide the Regulator with information and documents and to give evidence to the Regulator which is relevant to the operation of the REC Act if the Regulator has reason to believe that the person has such information or documents or is capable of giving such evidence. A person who fails to comply commits an offence (s 125A(3)).

Section 125B prevents the person from seeking to be excused from providing such information, documents and evidence on the grounds that it may incriminate the person. However, the information, documents and evidence cannot be used in criminal proceedings against the person other than proceedings for failing to provide the information, documents and evidence or for giving false or misleading evidence or information.

The Regulator is empowered by ss 125C and 125D to retain possession of and make and retain copies of documents produced under s 125A.

If a person provides information, documents or evidence in purported compliance with s 125A and knows that the information, documents or evidence is false or misleading in a material particular then the person commits an offence with a maximum penalty of 12 months imprisonment (new ss 125E and 125F).

Senate amendments

The House of Representatives passed the Bill on 12 December 2002. At approximately 3.30 am on the morning of 13 December 2002, the Senate made two amendments to the Bill before passing it. The House of Representatives has not reconsidered the Bill in its amended form. Therefore, the Bill has not yet been passed.

The more significant amendment made by the Senate was to amend s 40 of the REC Act to change the required GWh of renewable source electricity for 2010 from 9,500 GWh to 5% of the total number of GWh of electricity acquired from all sources under relevant acquisitions during 2009. Perhaps due to the time of day, the amendment (presumably inadvertently) deleted the remainder of s 40 thus removing from s 40 the details of the required GWh of renewable source electricity for years other than 2010. This will need to be corrected before the Bill is passed.

The other amendment made by the Senate was to amend s 162 of the REC Act to amend the terms of reference for the review of the operation of the REC Act.

Parer Report

On 20 December 2002, the Final Report of the *Council of Australian Governments' Energy Market Review* was released (Parer Report). The Parer Report recommended abolishing the MRET Scheme and the other State-based schemes aimed at reducing greenhouse gases and replacing them with a national emissions trading scheme. However, the report did recognise that if this is to occur then it will be necessary to provide a subsidy to investments entered into in response to the existing schemes.[10]

Mandatory Renewable Energy Target Review

On 25 March 2003, the Minister for the Environment and Heritage (Dr David Kemp) and the Minister for Industry, Tourism and Resources (the Hon Ian MacFarlane) announced the membership of the MRET Review Panel and the terms of reference for the panel's review of the operation of the REC Act. The MRET Review Panel received in excess of 3,000 submissions[11] and has been requested by the Minister to report by the end of September 2003.

[10] COAG, *Towards a Truly National and Efficient Energy Market – Council of Australian Governments' Energy Market Review* (December 2002) pp 57, 223-242.

[11] See the website relating to the MRET Review – http://www.mretreview.gov.au/.

In broad terms, the MRET Review is to review the operation of the REC Act to determine the extent to which the REC Act has contributed to reducing greenhouse gas emissions and encouraged additional generation of electricity from renewable energy sources and the need for any alternative approach. The full terms of reference are contained in Schedule 1 to this paper.

OVERVIEW OF TYPES OF TRANSACTIONS INVOLVING RECs

Sales of RECs sometimes occur in isolation. Such contracts involve the sale and purchase of a specified quantity of RECs for a specified price. The RECs must be delivered either around the time of the parties signing the contract or on one or more specified dates in the future. However, sales of RECs are often part of a broader transaction which also involves the sale of other Green Rights, the sale of electricity or an electricity derivative transaction.

To understand the background to such broader transactions, consider the case of an entity which wishes to construct, own and operate a power station to generate electricity from a "green" or "renewable" fuel source (for ease of reference, we will refer to this entity as "GenCo"). The project will often be debt financed. A condition of finance is typically that GenCo has entered into a long term (that is, 10 to 15 years) "Power Purchase Agreement" (referred to as a "PPA").

A typical PPA involves the sale of all electricity generated by the power station during that 10 to 15 year period (which we will call the "Generation Period") together with all Green Rights created in respect of that electricity. Due to the time lag in creating Green Rights, the Green Rights applicable to the last part of the Generation Period are created and transferred after the conclusion of the Generation Period. Variations to such a contract include the sale of only a fixed percentage of the electricity or the Green Rights or only certain types of Green Rights.

A further variation involves the sale of the electricity to NEMMCO in the NEM (for which the power station owner receives the spot price applicable to that region in the NEM). GenCo then hedges against the financial risk of receiving this fluctuating income by entering into an electricity derivative transaction[12] under

[12] Such transactions are referred to by multiple names, all of which are accurate. They are sometimes called "fixed/floating swaps" because they involve swapping the payment of a fixed amount for the payment of a floating amount. They are sometimes called "whole of meter swaps" because the notional quantity on which the payments are calculated is the actual metered quantity of electricity which is generated. They are sometimes called a "hedging contract" because they provide a hedge to the floating price payer against the risk of receiving a floating income for the electricity which it sells into the NEM at the spot price and because they provide a hedge to the fixed price payer against the risk of paying a floating expenditure for the electricity which it purchases in the NEM at the spot price. They are sometimes called "cash settled forward commodity contracts" because they provide for the "sale" of a commodity (being electricity) on a date in the future which is settled not by the physical delivery of electricity but by the payment of

which GenCo pays a floating amount and receives a fixed amount. These amounts are calculated for every half hour period (referred to as a "Calculation Period"). The floating amount is calculated by multiplying the spot price for the half hour in the relevant region of the NEM by the metered quantity of electricity generated in that half hour and sold by the owner through the NEM. The fixed amount is calculated by multiplying a "fixed price" by the same "notional" quantity of electricity. The "fixed price" is "fixed" in the sense that its amount or the formula for calculating its amount is pre-agreed. It may be a nominal amount which increases by agreed amounts during the term of the contract. It may increase in line with inflation or with variations in other indices. Note that no electricity is actually sold under such a transaction. Rather, it is a sale of a "notional quantity" of electricity.

An electricity derivative transaction in the above context often includes or is accompanied by a separate contract for the sale of Green Rights created in respect of the generated electricity – be it all, a fixed percentage of or certain types of those Green Rights.

It is appropriate, in passing, to mention the "Green Electricity Market" (known as "GEM"). GEM commenced operating in July 2001 and provided an internet based trading platform which enabled those industry participants who chose to become members of GEM to trade RECs in accordance with GEM's trading rules. Members would lodge offers to sell RECs and lodge bids to buy RECs with the "Market Administrator". The Market Administrator, in turn, would match bids and offers and stand in the middle of the market by acting as the counterparty to all transactions on the market.

GEM had the potential to provide a platform for the sale and purchase of other Green Rights and environmental instruments. However, on 30 June 2003, the GEM Governance Board announced that the GEM members had decided that the current climate for environmental markets did not make it feasible to continue operating GEM and thus it was decided to cease the operation of GEM.[13]

Later in this paper we will consider the various issues which need to be addressed when entering into sales of RECs in isolation and sales of RECs which are part of a broader transaction which also involves the sale of other Green Rights, the sale of electricity or an electricity derivative transaction. As background to that discussion, we will firstly consider the nature of some of the other greenhouse schemes which coexist and overlap with the MRET Scheme. We will then consider the impact of the Code and the *Corporations Act* 2001 (Cth) (*Corporations Act*) on the above transactions. We will then proceed to consider the various issues which need to be addressed when entering into those transactions.

the difference between the pre-agreed contract price and the NEM spot price at the time of delivery. Strictly speaking, such contracts involve the sale and purchase of a "notional" quantity of electricity.

[13] The Market Administrator of GEM was The Marketplace Company (M-co). See the statement relating to GEM on M-co's website – http://www.au.m-co.com/.

NSW GREENHOUSE GAS ABATEMENT SCHEME (ABATEMENT CERTIFICATES – NGACs AND LUACs)

Overview of the Scheme

The current version of the NSW Greenhouse Gas Abatement Scheme commenced on 1 January 2003. The current version of the scheme replaced an earlier version which had been imposed since 1997 under the NSW retail supplier's licence conditions. Licensed retailers were required to prepare annual reports (in accordance with the methodology approved by the Minister) relating to the carbon dioxide emissions arising from the production of the electricity they supplied. The methodology allowed for the notional "assignment" of energy and the associated greenhouse gas emissions from a generator to a retailer (via the execution of "Assigned Generation Declarations" (AGDs)) for the purpose of calculating the retailer's carbon dioxide emissions.[14] The discussion of the scheme in this paper relates to the current version of the scheme.

The scheme requires NSW electricity retailers and certain large customers (each of whom are known as "Benchmark Participants") to ensure that the greenhouse gas emissions which can be attributed to the electricity which they consume is less than a pre-determined benchmark level. A failure to comply with the benchmark will result in a penalty per tonne of excess emissions (Greenhouse Penalty). Excess emissions can be offset by surrendering NSW Greenhouse Abatement Certificates (NGACs) purchased from accredited Abatement Certificate Providers and by surrendering Large User Abatement Certificates (LUACs). The scheme therefore creates a demand among Benchmark Participants to acquire Abatement Certificates in order to reduce their excess emissions and thus their Greenhouse Penalty.

The Independent Pricing and Regulatory Tribunal of NSW (IPART) performs two distinct roles under the scheme:

(a) the role of "Compliance Regulator" – which involves overseeing Benchmark Participants' compliance with the scheme; and

(b) the role of "Scheme Administrator" – which involves overseeing the creation and transfer of NGACs by accredited Abatement Certificate Providers.

Duration of the Scheme

The scheme in its current form applies to the period from 1 January 2003 to 31 December 2012.

[14] For further details see the publication titled *Greenhouse Gas Emissions from Electricity Supplied in NSW: Emissions Workbook* (October 2000) by the NSW Ministry of Energy and Utilities (MEU) and the earlier version of this publication dated February 1999 by the NSW Department of Energy (DOE) (which was the predecessor to the MEU).

Overview of the Legislation

The scheme has been put in place by the following legislation and statutory instruments:

1. The *Electricity Supply Act* 1995 (NSW) (Supply Act)

   The relevant provisions were inserted into this Act by the *Electricity Supply Amendment (Greenhouse Gas Emission Reduction) Act* 2002 (NSW).

2. The *Electricity Supply (General) Regulation* 2001 (NSW) (Supply Regulation)

   The relevant provisions were inserted into this Regulation by:

   (a) the *Electricity Supply (General) Amendment (Greenhouse Gas Emission Reduction) Regulation* 2002 (NSW); and
   (b) the *Electricity Supply (General) Amendment (Greenhouse Gas Abatement Certificate Scheme) Regulation* 2003 (NSW).

3. The following Greenhouse Gas Benchmark Rules issued by the Minister for Energy under s 97K of the Supply Act:

   (a) *Greenhouse Gas Benchmark Rule (Compliance) No 1 of 2003* (Benchmark Rule 1)
   (b) *Greenhouse Gas Benchmark Rule (Generation) No 2 of 2003* (Benchmark Rule 2)
   (c) *Greenhouse Gas Benchmark Rule (Demand Side Abatement) No 3 of 2003* (Benchmark Rule 3)
   (d) *Greenhouse Gas Benchmark Rule (Large User Abatement Certificates) No 4 of 2003* (Benchmark Rule 4)
   (e) *Greenhouse Gas Benchmark Rule (Carbon Sequestration) No 5 of 2003* (Benchmark Rule 5)

In addition, it is a condition of an electricity retail supplier's licence issued under the Supply Act that the retail supplier comply with the provisions of the Supply Act relating to the scheme, its Greenhouse Gas Benchmark, the Supply Regulation and the Benchmark Rules (ss 97C(1), 97JC and 97KA(2) Supply Act).

Creating the Demand

Who is liable?

There are five classes of persons who are "Benchmark Participants".

A Class 1 Benchmark Participant is a "retail supplier" – that is, a person who holds a NSW retail supplier's licence (s 97BB(1) Supply Act and cl 11 Benchmark Rule 1).

A Class 2 Benchmark Participant is a person (such as an electricity generator) who is prescribed by the Regulations and who supplies electricity to a customer under an electricity supply arrangement that does not require the use of a NSW retail supplier's licence (because it is exempt from or is otherwise not covered by s 98 of the Supply Act) (s 97BB(1) Supply Act and cl 11 Benchmark Rule 1).[15]

A Class 3 Benchmark Participant is a person who is a registered "Market Customer" under the Code but who does not hold a NSW retail supplier's licence, but only in respect of an electricity load that the person has classified as a "market load" under the Code and that is supplied for use in New South Wales (s 97BB(1) Supply Act and cl 11 Benchmark Rule 1).

A Class 4 Benchmark Participant is a "large customer" who has elected to be subject to a Greenhouse Gas Benchmark (s 97BB(1) Supply Act and cl 11 Benchmark Rule 1).[16]

A Class 5 Benchmark Participant is a person who is carrying out a State significant development and who has elected to be subject to a Greenhouse Gas Benchmark (s 97BB(1) Supply Act and cl 11 Benchmark Rule 1).

An election must be made to IPART and has no effect unless IPART accepts the election (cl 73BB(1) Supply Regulation and cl 73BD(1) Supply Regulation). An election is only for a specified time period and can be revoked by the Benchmark Participant or cancelled in certain circumstances by IPART (cll 73BB(1), 73BD(5) and 73BE(1) Regulation).

How is liability calculated?

To comply with the scheme, a Benchmark Participant must ensure that its "Attributable Emissions" for a given calendar year do not exceed its "Greenhouse Gas Benchmark". Each of these is measured in tonnes of carbon dioxide equivalent of greenhouse gas emissions. The amount (if any) by which a Benchmark Participant's Attributable Emissions exceed its Greenhouse Gas Benchmark is its "Greenhouse Shortfall".

A Benchmark Participant's "Attributable Emissions" for a given calendar year are calculated as follows:

[15] Section 98 provides that an electricity supply arrangement will be unenforceable by any person (other than a retail customer under a customer supply contract) unless, at the time the person entered into the arrangement, the person was authorised by a licence to enter into the arrangement. There are various exceptions to s 98 – see s 98(2) of the Supply Act, cl 18 of Sched 6 to the Supply Act and cl 68 of the Supply Regulation. Macquarie Generation is the only generator currently prescribed (for the purposes of s 97BB(1) of the Supply Act) under cl 73B of the Supply Regulation in respect of its supply of electricity to Tomago Aluminium Company Pty Ltd's aluminium smelter.

[16] A "large customer" is defined in s 97AB of the Act to mean a "customer" (other than a "retail supplier") who uses 100 GWh or more of electricity at a single site in NSW in any year or uses 100 GWh or more of electricity at more than one site in NSW in any year (at least one of which uses 50 GWh or more of electricity in that year).

A "customer" is essentially someone to whose premises electricity is supplied. See the definitions of "customer", "wholesale customer" and "retail customer" in the Dictionary to the Supply Act. See also cl 73BA of the Supply Regulation.

Total Electricity Purchased * NSW Pool Coefficient
less
NGACs surrendered for that year
less
RECs counted for that year * NSW Pool Coefficient
less
LUACs surrendered for that year

The Benchmark Participant's "Total Electricity Purchased" for the relevant calendar year is calculated as specified in cl 7 of Benchmark Rule 1. The methodology varies between classes of Benchmark Participants.

The "NSW Pool Coefficient" for the relevant calendar year represents the average emissions per unit of electricity delivered at transmission nodes for all generating systems supplying the "notional NSW pool" (being electricity delivered to New South Wales, the Australian Capital Territory and net exports to other States). It is 0.897 for 2003 and 0.906 for 2004 and will be determined by IPART for each of 2005 to 2012 in accordance with the method specified in cl 9 of Benchmark Rule 1.

A Benchmark Participant's "Greenhouse Gas Benchmark" for a given calendar year is calculated as follows:

Total Electricity Sold / Total State Electricity Demand
multiplied by
Electricity Sector Benchmark (being Total State Population multiplied by State Greenhouse Gas Benchmark)

The Benchmark Participant's "Total Electricity Sold" for the relevant calendar year is calculated as specified in cl 8 of Benchmark Rule 1. The methodology varies between classes of Benchmark Participants.

The Total State Electricity Demand for the relevant calendar year is determined by IPART in accordance with cl 9.2 of Benchmark Rule 1.

The Total State Population for the relevant calendar year is determined by IPART in accordance with cl 9.3 of Benchmark Rule 1.

The State Greenhouse Gas Benchmarks for each calendar year are set out in s 97B of the Supply Act and are as follows:

(a) for 2003 – 8.65 tonnes of carbon dioxide equivalent of greenhouse gas emissions per head of State population;
(b) for 2004 – 8.31 tonnes of carbon dioxide equivalent of greenhouse gas emissions per head of State population;
(c) for 2005 – 7.96 tonnes of carbon dioxide equivalent of greenhouse gas emissions per head of State population;
(d) for 2006 – 7.62 tonnes of carbon dioxide equivalent of greenhouse gas emissions per head of State population; and
(e) for each of 2007, 2008, 2009, 2010, 2011 and 2012 – 7.27 tonnes of carbon dioxide equivalent of greenhouse gas emissions per head of State population.

Subject to one qualification, if a Benchmark Participant has a Greenhouse Shortfall for a given year then the Greenhouse Penalty is payable in respect of that shortfall. The qualification is that no Greenhouse Penalty is payable for a year if the Greenhouse Shortfall is carried forward to the next year. This may be done for all years except 2007 and subject to the carried forward shortfall not exceeding 10% of the Benchmark Participant's Greenhouse Gas Benchmark for the year (s 97BE Supply Act).

What affects the demand for and the price of NGACs?

The demand for NGACs is therefore a function of the value of the State Greenhouse Gas Benchmark and the price that Benchmark Participants will be prepared to pay for NGACs is a function of the rate of the Greenhouse Penalty.

The amount of the Greenhouse Penalty will initially be $10.50 per tonne of carbon dioxide equivalent of Greenhouse Shortfall for the relevant calendar year. It will be adjusted annually (commencing on 1 July 2004) in accordance with movements in the Consumer Price Index (CPI) (All Groups, Sydney) (s 97CA Supply Act and cl 73C Supply Regulation).

The Greenhouse Penalty is not tax deductible. However, the cost of purchasing NGACs is tax deductible. Therefore, assuming a corporate tax rate of 30%, a Greenhouse Penalty of $10.50 corresponds to a maximum purchase price for NGACs of $15 (above which it would be cheaper to pay the Greenhouse Penalty).[17]

Greenhouse Gas Benchmark Statements

A Benchmark Participant must lodge a "Greenhouse Gas Benchmark Statement" for the relevant calendar year with IPART on or before 1 March in the following year or any later date permitted by IPART (s 97CB(1) Supply Act). That statement must set out (among other things) an assessment of the Benchmark Participant's Greenhouse Gas Benchmark for the relevant year, its liability (if any) for the Greenhouse Penalty for the relevant year and its liability (if any) for the Greenhouse Penalty for any Greenhouse Shortfall carried forward from the previous year (s 97CB(2) Supply Act). The statement must also be accompanied by details of all Abatement Certificates (that is, NGACs and LUACs) which the Benchmark Participant seeks to surrender and all RECs which it seeks to be counted for the relevant year and for the carried forward shortfall (if any) from the previous year (s 97CB(4) Supply Act).

A Benchmark Participant's assessment of its Greenhouse Shortfall (if any) and its liability (if any) for the Greenhouse Penalty in its Greenhouse Gas Benchmark Statement for a given calendar year is taken to be its Greenhouse Shortfall and liability for the Greenhouse Penalty for that year unless IPART makes its own

[17] The maximum price which a Benchmark Participant would be prepared to pay for an NGAC, given a Greenhouse Penalty of $10.50 and assuming a corporate tax rate of 30%, can be calculated by dividing the value of the charge by (1 minus the tax rate) – that is, $10.50 / (1 – 0.3) = $15.

assessment (cl 73E(1) Supply Regulation). The assessment is taken to have been made on 1 March in the year following the year covered by the assessment or such later date that the Greenhouse Gas Benchmark Statement is lodged (cl 73E(3) Supply Regulation). IPART may make an assessment of a Benchmark Participant's Greenhouse Shortfall and liability for the Greenhouse Penalty for a given calendar year if the Benchmark Participant does not lodge a Greenhouse Gas Benchmark Statement for that year (cl 73EA Supply Regulation). Clauses 73EB, 73EC and 73ED of the Regulation set out the circumstances in which assessments can be amended.

The Greenhouse Penalty is payable by the Benchmark Participant on 1 March in the year following the year to which the penalty relates or on such later date as is determined by IPART (s 97CA(4) Supply Act).

Surrender of NGACs and LUACs and counting of RECs

An Abatement Certificate cannot be surrendered by a Benchmark Participant unless it is registered and the registration is in force, it was created in relation to an activity that took place before the end of the year to which the Greenhouse Gas Benchmark Statement relates and the Benchmark Participant is recorded in the Register of Abatement Certificates as the owner of the Abatement Certificate (s 97CC Supply Act).

For Class 1, 2 or 3 Benchmark Participants, a REC may be counted by the Benchmark Participant towards its Greenhouse Gas Benchmark, or to abate its Greenhouse Gas Shortfall, for a given calendar year if the following are satisfied:

(a) the REC has been surrendered by the Benchmark Participant under the REC Act or IPART is satisfied that an offer to surrender the REC has been made under the REC Act for that year;
(b) the Benchmark Participant's Greenhouse Gas Benchmark Statement specifies the number of RECs surrendered or proposed to be surrendered under the REC Act for that year; and
(c) the costs of, or associated with, the RECs have not been paid or reimbursed to the Benchmark Participant by a Class 4 or 5 Benchmark Participant or otherwise passed on by the Benchmark Participant to a Class 4 or 5 Benchmark Participant (cl 73DA(1) Supply Regulation).

For Class 4 or 5 Benchmark Participants, a REC may be counted by the Benchmark Participant towards its Greenhouse Gas Benchmark, or to abate its Greenhouse Gas Shortfall, for a given calendar year if the following are satisfied:

(a) the REC has been surrendered by another Benchmark Participant under the REC Act or IPART is satisfied that an offer to surrender the REC has been made under the REC Act for that year;
(b) the Benchmark Participant's Greenhouse Gas Benchmark Statement specifies the number of RECs proposed to be counted for that year; and
(c) the costs of, or associated with, the RECs have been paid or reimbursed by the Benchmark Participant to another Benchmark Participant or otherwise

passed on to the Benchmark Participant by another Benchmark Participant and evidence of this has been provided to IPART with the Benchmark Participant's Greenhouse Gas Benchmark Statement (cl 73DA(2) Supply Regulation).

In addition to the above, there is a cap on the number of RECs which a Benchmark Participant may count towards its Greenhouse Gas Benchmark, or to abate its Greenhouse Gas Shortfall, for a given calendar year. The maximum number of RECs which a Benchmark Participant may count for a given calendar year is calculated as follows (these calculations essentially exclude RECs surrendered in relation to consumption outside New South Wales):

1. In the case of a Class 3 Benchmark Participant, the total number of RECs is calculated by multiplying the total amount in MWh of the Benchmark Participant's relevant acquisitions of electricity purchased for use in New South Wales in the year by the renewable power percentage for the year and rounding the result to the nearest MWh.
2. In the case of a Class 1 or 2 Benchmark Participant, the total number of RECs is calculated by:
   (a) multiplying the total amount in MWh of the Benchmark Participant's relevant acquisitions of electricity purchased for use in New South Wales in the year by the renewable power percentage for the year and rounding the result to the nearest MWh; and
   (b) subtracting from that amount the number of any RECs in respect of which the cost has been passed on to a Class 4 or 5 Benchmark Participant.
3. In the case of a Class 4 or 5 Benchmark Participant, the total number of the RECs is calculated:
   (a) if electricity is purchased at a "connection point" (as defined in the Code) located in a "distribution network" (as defined in the Code), by multiplying the total amount in MWh of electricity purchases related to the electricity load covered by the election in the year concerned by the renewable power percentage for the year and by the "distribution loss factor" (as defined in the Code) applicable to the connection point and rounding the result to the nearest MWh; or
   (b) if electricity is not so purchased, by multiplying the total amount in MWh of electricity purchased related to the electricity load covered by the election in the year concerned by the renewable power percentage for the year and rounding the result to the nearest MWh (cl 73DB Supply Regulation).

Creating the Supply

Types of Abatement Certificates

There are two types of Abatement Certificates:

(a) "NSW Greenhouse Abatement Certificates" (referred to as "NGACs"). These are transferable Abatement Certificates which may be created in respect of electricity generation, carbon sequestration and demand side abatement activities (s 97F Supply Act, cl 73L Supply Regulation); and
(b) "Large User Abatement Certificates" (referred to as "LUACs"). These are non-transferable Abatement Certificates which may be created in respect of large user abatement activities (s 97F Supply Act, cl 73LA Supply Regulation).

As the focus of this paper is on energy generation projects, it is beyond the scope of this paper to consider carbon sequestration, demand side abatement and large user abatement activities. This s of the paper will therefore focus on transferable Abatement Certificates (that is, NGACs) created in relation to electricity generation activities.

Accredited Abatement Certificate Providers

Abatement Certificates can only be created by accredited Abatement Certificate Providers and then only in relation to those activities in relation to which the accredited Abatement Certificate Provider has been accredited (s 97D Supply Act). A person is eligible for accreditation as an Abatement Certificate Provider if the person conducts one or more of the above activities and satisfies the various other requirements in ss 73G to 73GC of the Supply Regulation and Benchmark Rules 2, 3, 4 and 5.

Benchmark Rule 2 applies to electricity generation activities. Under cl 5 of Benchmark Rule 2, IPART may accredit:

(a) Generators (that is, persons that engage in the activity of owning, controlling, or operating a generating system that supplies electricity to a "transmission" or "distribution" system (as defined in the Code));
(b) Deemed Retailers (that is, an electricity retailer to whom the output of a "Category A generating system"[18] has been assigned under the former Assigned Generation Declarations);
(c) any person entitled to create NGACs under Benchmark Rule 2; and
(d) any person that has been assigned, pursuant to the Supply Regulation, an entitlement to create NGACs in accordance with Benchmark Rule 2,

as Abatement Certificate Providers in respect of the generation of electricity in a manner that results in reduced emissions of greenhouse gases by a generating system that supplies any electricity at a connection point connected to the NSW transmission and distribution network or a transmission or distribution network interconnected with the NSW network (that is, the interconnected networks of the NEM).

[18] As defined in the publication titled *Greenhouse Gas Emissions from Electricity Supplied in NSW: Emissions Workbook* (October 2000) by the MEU.

Creation of Abatement Certificates

A person who is an accredited Abatement Certificate Provider in relation to an activity referred to above may create an Abatement Certificate in respect of that activity in accordance with the relevant provisions of the Supply Act, the Supply Regulation and the Benchmark Rules. The type of Abatement Certificate created will depend on the activity. Each Abatement Certificate represents 1 tonne of carbon dioxide equivalent of greenhouse gas emissions abated by the activity in respect of which it was created (s 97EA Supply Act).

An Abatement Certificate can be created by an accredited Abatement Certificate Provider immediately after the activity in respect of which it was created takes place (s 97EC(1) Supply Act). It cannot be created more than six months after the end of the year in which the activity in respect of which it was created takes place (s 97EC(2) Supply Act). The time when an activity is considered to have taken place is specified in the Benchmark Rules.

Each electricity generating system has a baseline which is determined by IPART in accordance with Benchmark Rule 2. (As an aside, IPART also determines baselines for other activities in relation to which Abatement Certificates can be created.) An Abatement Certificate Provider may only create Abatement Certificates for activities in excess of its baseline (cl 73KA Regulation).

The number of Abatement Certificates able to be created from an electricity generating system is determined in accordance with the formulae in Benchmark Rule 2. Significantly, these formulae deduct from the total generation the amount of the baseline. For generation from some renewable energy fuel sources there is also a deduction for the amount of any RECs created in respect of that generation (thus avoiding double counting of the same generation under two regimes).[19] However, additional NGACs may be created (thus introducing double counting) for electricity generated from landfill gas, sewage gas and other methane gas from renewable energy fuel sources (cl 9.4 Benchmark Rule 2).

Nature of Abatement Certificates and registration

An Abatement Certificate has no force or effect until its creation is registered by IPART (s 97ED(1) Supply Act). An accredited Abatement Certificate Provider seeking to register the creation of an Abatement Certificate must apply to IPART for that registration (s 97ED(2) Supply Act). If IPART accepts the application, IPART must create an entry for the Abatement Certificate in the register of Abatement Certificates maintained by IPART. The name of the person who created the Abatement Certificate must be recorded by IPART as the owner of the Abatement Certificate (s 97ED(4) Supply Act). An Abatement Certificate remains in force until cancelled by IPART (s 97EE(1) Supply Act).

[19] See in particular, Equation 2 in Benchmark Rule 2.

Transfer issues

The transfer of an Abatement Certificate does not take effect until the transfer is registered by IPART (s 97FB(1) Supply Act). The parties to a transfer must apply to IPART to register the transfer (s 97FB(2) Supply Act).

However, the registration of a supposed transfer does not have the effect of transferring an Abatement Certificate if the transaction between the supposed seller and the supposed buyer was not effective to transfer the Abatement Certificate (s 97FE Supply Act). Despite this, the effect of s 97FD of the Supply Act is that a person who purchases an Abatement Certificate in good faith for value from the registered owner and without notice of any fraud on the part of the registered owner will receive good title.

GREEN POWER ACCREDITATION PROGRAM

Duration of the Program

The Green Power Accreditation Program is a voluntary program which was launched in 1997 by the NSW Government's Sustainable Energy Development Authority (SEDA). The program now operates nationally through joint collaboration by participating State and Territory government agencies in New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory. These agencies are known collectively as the National Green Power Accreditation Steering Group (NGPASP) with SEDA appointed as the Project Manager. The program does not have an expiry date.

Overview of the Relevant Documents

The rules for the program are contained in the *National Green Power Accreditation Program – Accreditation Document* (Version 3, June 2003) (Accreditation Document).

Details of the Program

The program involves the creation of "Green Power Products" by electricity retailers for provision to electricity customers. The demand for such products is therefore customer driven. Such products enable electricity retailers to provide a green tariff option to their customers. In exchange for paying the additional tariff, the retailer agrees to ensure that an equivalent amount of renewable energy is produced from "Green Power Generators" (s 2.1 Accreditation Document).

Each Green Power Product needs to be accredited by SEDA under the program (s 2.1.1 Accreditation Document). Electricity retailers must use the Green Power Product logo in advertisements and marketing associated with their Green Power Products (s 4.4 Accreditation Document).

To meet the demand for their Green Power Products, electricity retailers must purchase sufficient "Green Power Rights" from Green Power Generators. These Green Power Rights are the right to claim (under the Green Power Accreditation Program) any eligible Green Power generation (or a portion of such generation) from a Green Power Generator that has occurred during a defined period (Appendix C Accreditation Document). As of 1 July 2001, retailers have been able to purchase and on-sell the Green Power Rights under the program separately to the electricity produced from a Green Power Generator (s 2.3 Accreditation Document).

Green Power Rights will only be valid where it can be established that the associated electricity was generated (s 2.3.1 Accreditation Document). In addition, Green Power Rights are only valid in relation to the "settlement period" in which the generation to which it is associated has occurred, except where carryover to the next period has been authorised under the flexibility mechanisms outlined in s 3.6 of the Accreditation Document, or in the case of deemed Green Power Rights from small scale systems (s 2.3.1 Accreditation Document). There is a settlement period from 1 July 2002 to 31 December 2003 and after that each calendar year is a settlement period (s 3.6 Accreditation Document).

All electricity generators used in a Green Power Product must be approved as a Green Power Generator by SEDA. Broadly speaking, Green Power Generators are "generators" (or more specifically, generating units) that are approved by SEDA as generators that result in greenhouse gas emission reduction, net environmental benefits and are based primarily on an eligible renewable energy resource (s 2.2 Accreditation Document). "Based primarily" means more than half of the output must be attributed to eligible renewable energy sources.

"Eligible renewable energy resources" include:

(a) solar power (photovoltaic and thermal);
(b) wind;
(c) biomass (landfill gas, municipal solid waste, agricultural wastes, energy crops, wood wastes). [Note: Only wood sources from existing sustainably managed forestry plantations and clearing of specified noxious weeds are accepted. Use of any materials from high conservation-value forests is not acceptable.];
(d) hydro-electric power (small-scale or on existing dams). [Note: Projects must have adequate environmental flows. Projects that involve construction of new dams or diversion of rivers are generally not acceptable under Green Power.];
(e) geothermal; and
(f) wave and tidal power (s 2.2 Accreditation Document).

Only the portion of the energy generated from eligible renewable energy sources is eligible for Green Power approval (s 5.2.2 Accreditation Document).

There are two types of Green Power Generators. Firstly, there are "New Green Power Generators" – being electricity generators or increases in generator capacity which were commissioned or first sold energy (whichever is earlier) after 1 January 1997. Secondly, there are "Existing Green Power Generators" – being electricity generators or increases in generator capacity which were commissioned or first sold energy (whichever is earlier) prior to 1 January 1997 (s 2.2.1 Accreditation Document). An electricity retailer must purchase 80% of its Green Power Rights from New Green Power Generators (s 3.4 Accreditation Document).

There are no formal requirements relating to the method by which Green Power Rights are transferred. The general position is that electricity retailers are required to transfer (into a designated account) RECs from a Green Power Generator for each MWh of "new" Green Power generation acquired by the retailer and sold as part of a Green Power Product within a settlement period. Retailers are not permitted to surrender these RECs for the purposes of the MRET Scheme. However, there are a couple of exceptions to this position (s 3.7 Accreditation Document).

GAS ELECTRICITY CERTIFICATES (GECs)

Duration of the Scheme

The Queensland 13% Gas Scheme (Queensland Scheme) will require electricity retailers and other liable parties to source at least 13% of their electricity sold in Queensland from gas-fired generation from 1 January 2005. This is intended to diversify Queensland's energy mix towards a greater use of gas and encourage new gas infrastructure in Queensland. It is intended that greenhouse gas emissions will be reduced by more than 1,000,000 tonnes in the first year of operation of the Queensland Scheme.[20]

In September 2002, a Final Position Paper[21] was released setting out the final design of the Queensland Scheme. This will form the basis on which legislation is drafted to implement the Queensland Scheme. As at the time of preparing this paper, it is expected that a draft bill will soon be released for consultation with industry participants and that the bill will be introduced in the Parliament in late 2003. The details of the Queensland Scheme which are contained in this paper have been based on the material contained in the Final Position Paper.

The Queensland Scheme is intended to commence on 1 January 2005 and will operate for 15 years until 31 December 2019.[22]

[20] See the discussion of the Queensland Scheme on the website of the Queensland Office of Energy –http://www.energy.qld.gov.au/.

[21] Office of Energy, Queensland Treasury, *The Queensland 13% Gas Scheme – Final Position Paper* (September 2002). A copy can be obtained from the above website of the Queensland Office of Energy.

[22] Clause 2.1 Final Position Paper.

Overview of the Legislation

It is intended to implement the Queensland Scheme by making amendments to the *Electricity Act* 1994 (Qld).

Creating the Demand

A "liable party" will be required to calculate the amount of electricity sold by it in Queensland during a given year. In general, liable parties will be parties who are connected to, or sell to end-users connected to, a "major grid" (that is, a grid with an installed capacity which exceeds 100 MW). There are currently two Queensland grids that fit this description – the National Grid and the Mica Creek Grid (which supplies electricity to the Mount Isa region).[23]

A given amount of electricity will only attract liability once in the chain of transactions under which it is sold (for example, sales to NEMMCO and sales prior to this will not incur a liability).[24] The liable party will be required to surrender a number of Gas Electricity Certificates (GECs) which corresponds to 13% of the amount of electricity sold in a given year, by the last business day in April in the following year. If the liable party does not surrender sufficient GECs then the party will need to pay a penalty for each GEC which it does not surrender.[25]

In 2005, the penalty will be $11 per GEC not surrendered. In 2006 to 2011, the penalty will be the previous year's penalty indexed in accordance with the change in the Consumer Price Index (CPI) (All Groups, Brisbane). In 2012 to 2019, the penalty will be the same as it was in 2011.[26]

The penalty will not be tax deductible. However, the cost of purchasing GECs will be tax deductible. Therefore, assuming a corporate tax rate of 30%, a penalty of $11 corresponds to a maximum purchase price for GECs of $15.71 (above which it would be cheaper to pay the penalty).[27]

Creating the Supply

All power stations will be eligible to create GECs provided they are accredited and generate electricity which is generated from an eligible fuel source, generated above their baseline and generated to support electricity load in Queensland (this is dealt with by applying a specially calculated Queensland Usage Factor).[28]

[23] Clause 1.5 Final Position Paper.
[24] Clause 2.4.1 Final Position Paper.
[25] Clauses 2.4.12 and 2.4.13 Final Position Paper.
[26] Clause 2.4.13 Final Position Paper.
[27] The maximum price which a liable entity would be prepared to pay for a GEC, given a penalty of $11 and assuming a corporate tax rate of 30%, can be calculated by dividing the value of the penalty by (1 minus the tax rate) – that is, $11 / (1 – 0.3) = $15.71.
[28] Clause 1.5 Final Position Paper.

Accredited parties will be able to create one GEC for every MWh of eligible electricity which they generate. A GEC can be created at any time up to and including the eleventh month to occur after the month in which the electricity was generated.[29] The accredited party who creates the GEC will own the GEC. GECs will be registered on an internet-based electronic GEC Registry.[30] GECs will have a limited life span of three calendar years (being the year in which it was created and the next two years).[31]

The Queensland Scheme is designed to facilitate new investment in gas-fired electricity generation. Therefore, a baseline date of 24 May 2000 has been established and only additional or new gas-fired generation beyond that which was generated at this date is eligible to create GECs.[32]

THE NATIONAL ELECTRICITY MARKET ("NEM") AND THE NATIONAL ELECTRICITY CODE

Relevant Background

The National Electricity Market (referred to as the "NEM") commenced on 13 December 1998. It is the market for the wholesale supply and purchase of electricity in Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia (Tasmania will join the NEM following the completion of the Basslink network connecting Tasmania to Victoria[33]). The NEM includes a regime of open access to the transmission and distribution networks in the above jurisdictions which facilitates the wholesale supply and purchase of electricity.

The NEM is regulated under the National Electricity Law. The National Electricity Law takes effect by the enactment of similar legislation in each of the above jurisdictions. It is contained in the Schedule to the *National Electricity (South Australia) Act* 1996 (SA) and takes effect in that State as a result of that Act. The corresponding legislation in each of the other jurisdictions effectively provides that the National Electricity Law (as set out in the Schedule to the South Australian Act) applies as a law of that State or Territory.[34]

The Code is established under the National Electricity Law. It has separate chapters governing registration as a Code Participant (ch 2), the operation of the wholesale electricity market (ch 3), connection and access to transmission and distribution networks (ch 5), pricing for the use of those networks (ch 6), metering (ch 7), power system security (ch 4) and dispute resolution (ch 8). It also deals

29 Clause 2.5.2 Final Position Paper.
30 Clause 1.5 Final Position Paper.
31 Clause 2.5.3 Final Position Paper.
32 Clause 1.5 Final Position Paper.
33 NECA website – http://www.neca.com.au/.
34 Section 6, *National Electricity (New South Wales) Act* 1997 (NSW), s 6, *Electricity – National Scheme (Queensland) Act* 1997 (Qld), s 6, *National Electricity (Victoria) Act* 1997 (Vic) and s 5, *Electricity (National Scheme) Act* 1997 (ACT).

with other less significant issues. The Code is administered by National Electricity Code Administrator Limited (NECA).

The wholesale electricity market (which is often referred to as the "NEM" or the "spot market" or the "pool") is operated and administered by NEMMCO. Its key structural features can be summarised as follows:

(a) with the exception of very small generating units, all generators are required to sell the electricity which they generate from their generating units to NEMMCO in the NEM and to participate in NEMMCO's central dispatch process;

(b) aside from electricity which is purchased directly from these very small generating units, the electricity which retailers sell to customers is purchased by those retailers from NEMMCO in the NEM;

(c) the one "spot price" applies to all electricity sold or purchased within a given region in the NEM in a given half hour. This spot price varies from one half hour to the other and can vary from -$1,000 to +$10,000 per MWh;

(d) generators submit "dispatch offers" to NEMMCO for each generating unit (with the capacity for each generating unit divided into 10 price bands). Subject to any variations due to physical network constraints or other circumstances involving market failure, generators are dispatched according to their dispatch offers (with lower offers being dispatched in preference to higher offers). The most expensive offer which is dispatched in a given five minute period determines the "dispatch price" for that five minute period. The time weighted average of the dispatch prices applying during a given half hour period is the "spot price" for that half hour period;

(e) retailers are exposed to significant financial risk (that is, "price risk") as they typically sell electricity to customers at a fixed price while purchasing that electricity in the NEM at a price which could far exceed the price passed on to customers;

(f) generators are exposed to significant financial risk as the price which they receive from the NEM for the electricity which they generate could vary between -$1,000 to +$10,000 per MWh ("price risk") and the amount of electricity which they generate and sell is determined by NEMMCO in the central dispatch process ("volume risk");

(g) retailers "hedge" against the above price risk by entering into a variety of electricity derivative transactions with generators. These contracts also provide a "hedge" to generators against the price risk faced by generators in the NEM. Retailers and generators are therefore natural counterparties;

(h) viewed from another perspective, generators assume a "volume risk" by entering into an electricity derivative transaction without generating an equivalent volume of electricity and selling it into the NEM in the corresponding period. Generators "hedge" against this volume risk by ensuring that the strategy for submitting dispatch offers which they adopt in the NEM includes offering sufficient volumes of capacity at sufficiently low prices to ensure that they generate as least as much electricity as is covered by their electricity derivative transactions;

(i) retailers also become exposed to a "volume risk" if they have entered into electricity derivative transactions for quantities which exceed the quantities of electricity which they purchase in the NEM and on-sell to customers;

(j) there is only a very limited role for parties seeking to be a counterparty to an electricity derivative transaction without purchasing or selling a corresponding volume of electricity in the NEM, due to the substantial risks involved in such conduct;

(k) if a generator in one region enters into an electricity derivative transaction with a retailer in another region then the generator becomes exposed to an "inter-regional risk" and should hedge against this by entering into a different kind of electricity derivative transaction with a generator in the retailer's region;

(l) a number of electricity derivative transactions contain unique terms and conditions which reflect the circumstances faced by one or both counterparties in the NEM or by retailers in the downstream retail market. Such contracts are therefore fairly illiquid and are not suitable for trading between different counterparties. The nature of the terms of these contracts is a further reason why there is such a limited role in the electricity derivatives market for participants who do not trade in the NEM; and

(m) most electricity derivative transactions entered into by NEM participants are private "over-the-counter" transactions, the terms of which remain confidential to the counterparties. Very little volume is the subject of derivatives entered into in the public market.

Section 9 of the National Electricity Law effectively provides that a person must not engage in the activity of owning, controlling or operating a generating system that supplies electricity to a transmission or distribution system unless the person is registered under the Code as a Generator, is the subject of a derogation under the Code from the requirement to register or is exempt under the Code from the requirement to register.

Clause 2.2.1(c) of the Code (in ch 2) empowers NEMMCO to exempt a person or a class of persons from the requirement to register as a Generator. NEMMCO has exempted all generating units with a total nameplate rating of less than 5 MW from the need to register.[35]

When registering as a Generator under the Code, the Generator must classify each generating unit as either "scheduled" or "non-scheduled" (scheduled generating units are subject to NEMMCO's central dispatch process and non-scheduled generating units are not) and as either "market" or "non-market" (the output of market generating units is sold to NEMMCO in the wholesale electricity market and the output of non-market generating units is typically sold to the Local Retailer).[36]

[35] For a full description of all exempt generating units see NEMMCO's publication titled *Generator Registration Guide*, which is available on NEMMCO's website – http://www.nemmco.com.au/.

[36] Clauses 2.2 to 2.5 of the Code.

Relevance to PPAs

Taking the above into consideration, GenCo has three options in relation to the sale of the electricity which it generates from its power station.[37]

Firstly, it could sell all of the electricity to NEMMCO in the spot market. It would therefore classify the power station as a "market generating unit" for the purposes of the Code (see cl 2.2.4 of the Code).

Secondly, it could sell all of the electricity to the "Local Retailer" (as defined in the Code) for a price agreed between the parties (this could be a fixed price, a price which increases in line with inflation or some other index or a price which equals the spot price in the spot market). It would therefore classify the power station as a "non-market generating unit" for the purposes of the Code (see cl 2.2.5 of the Code).

Thirdly, it could sell all of the electricity to a third party (BuyCo) for a price agreed between the parties. However, for this transaction to be possible, BuyCo would need to on-sell the electricity either to NEMMCO or to the Local Retailer. This is because the Code effectively requires all of the electricity exported from a power station to the local network to ultimately be sold either to the Local Retailer or to NEMMCO in the spot market (see cll 2.2.4 and 2.2.5 of the Code).

If GenCo sells all of its electricity to BuyCo under the third of the above options and BuyCo wishes to on-sell that electricity to NEMMCO then BuyCo needs to become the registered Generator under the Code in order to facilitate that on-sale to NEMMCO. This is because cl 2.2.4 of the Code requires a power station whose output is ultimately sold to NEMMCO to be classified as "market" and requires the person registered as the Generator to be the seller to NEMMCO.

In theory, cl 2.2.1(b) of the Code allows BuyCo to register as a Generator as "a person who otherwise supplies electricity to a transmission or distribution system". However, registration by BuyCo under this cl would not give GenCo an exemption from the requirement to register. Given that NEMMCO only registers one entity in relation to each power station, it is necessary (from a practical perspective) for BuyCo to register in a way that gives GenCo an exemption from the requirement to register.

As a result, the only practical means by which BuyCo can obtain the necessary registration as a Generator is to register as the Intermediary of GenCo under the intermediary provisions in cl 2.9.3 of the Code. These intermediary provisions allow a person to be registered as the "Intermediary" of a second person who is otherwise required to be registered and then provide that second person with an exemption from that requirement.

Registration as an Intermediary has several consequences for BuyCo and GenCo. Firstly, BuyCo will be the registered Generator under the Code and

[37] I have ignored the possibility of selling all of the output to a large customer located nearby, thus avoiding the need to export the electricity onto the local distribution network.

therefore will acquire the rights and obligations under the Code which attach to the registered Generator. Secondly, GenCo will be exempted from registering under the Code. However, GenCo will be required by NEMMCO to sign a Deed under which it accepts liability for the acts, omissions, statements, representations and notices of BuyCo. As a result, GenCo will still be bound by the Code.

A couple of commercial issues arise for consideration by GenCo and BuyCo. There is an issue as to whether it is appropriate for BuyCo to bear all the costs of registration under the Code – GenCo may agree to reimburse BuyCo for those costs. There is also an issue as to whether it is appropriate for BuyCo to be liable for all Code breaches – GenCo may agree to indemnify BuyCo for any liability for breach of the Code which BuyCo incurs as a result of the acts or omissions of GenCo.

If the power station was to be scheduled then it would be subject to NEMMCO's central dispatch process and there would therefore be limits on its operation. However, due to the unreliable nature of power stations using green or renewable fuel sources, these power stations are normally unscheduled and therefore not subject to NEMMCO's central dispatch process.

If GenCo sells its electricity to NEMMCO in the spot market then it is exposed to the financial risk associated with the fluctuating spot price and may choose to hedge against that risk by entering into a fixed/floating swap.

CORPORATIONS ACT

Need for an AFS Licence

Most corporate entities involved in the electricity market are covered by the *Corporations Act*.[38] This s of this paper applies to such entities.

A party (of the type described above) which enters into a contract which is a "derivative" for the purposes of the *Corporations Act*, will need to obtain an Australian Financial Services Licence (AFS Licence) under the *Corporations Act*.[39] A party wishing to obtain an AFS Licence needs to apply for such a licence from the Australian Securities and Investments Commission (ASIC).[40]

[38] Some entities may be exempt from the application of the *Corporations Act* in respect of a limited range of their activities. Section 5F of the *Corporations Act* enables a State or Territory to pass a law which prevents the *Corporations Act* from applying to certain entities in that State or Territory.

[39] An exception to this is where the contract was entered into on a "financial market" (as defined in s 767A of the *Corporations Act*) in which case the person would not be taken to have "issued" a financial product for the purposes of s 761E of the *Corporations Act* with the result that the chain of reasoning in the paragraph below would not apply to that party.

[40] The application process for an AFS Licence is reasonably complicated and time consuming and is explained in great detail on the ASIC website – http://www.asic.gov.au/.

The above consequence arises due to the combined application of a number of relatively long and complex provisions in the *Corporations Act* and the *Corporations Regulations* 2001 (Cth) (Corporations Regulations). It is beyond the scope of this paper to examine each such provision in detail and parties should seek specific legal advice on this issue. However, by way of brief summary:

1. A “derivative” is a “financial product” for the purposes of the *Corporations Act* (s 761A and ss 762A to 765A *Corporations Act* – see, in particular, para 764A(1)(c)).
2. A party which enters into a derivative is taken to have “issued” a financial product for the purposes of the *Corporations Act* (s 761E *Corporations Act* and Reg 7.1.04D).[41]
3. Issuing a financial product constitutes “dealing” in a financial product for the purposes of the *Corporations Act* (para 766C(1)(b) *Corporations Act)*.
4. Dealing in a financial product constitutes “providing a financial service” for the purposes of the *Corporations Act* (para 766A(1)(b) *Corporations Act)*.
5. Carrying on a business which involves providing financial services (by entering into derivatives) amounts to “carrying on a financial services business” for the purposes of the *Corporations Act*.[42]
6. A person that carries on a financial services business must hold an AFS Licence covering the provision of the financial services (subs 911A(1) *Corporations Act)*. Failure to hold the necessary AFS Licence is an offence under s 1311 of the *Corporations Act*.[43]

When applying for an AFS Licence, the relevant corporation will need to closely examine the range of activities which it is involved in as each activity which requires an AFS Licence needs to be specified in the licence. For example, some corporations will find that their activities include not only dealing in a financial product but also “making a market” in a financial product (see the definition of “making a market” in s 766D of the *Corporations Act)*. Such an activity needs to be covered by the AFS Licence. The type of financial product (for example, electricity derivative) also needs to be specified in the AFS Licence.

As the holder of an AFS Licence, a party will be subject to various disclosure and other obligations under the *Corporations Act* and various licence conditions. The exact nature of these obligations will depend on the circumstances (including whether any of the party’s counterparties fall under the definition of “retail client” in s 761G of the *Corporations Act*). However, it is beyond the scope of this paper to discuss these obligations and conditions.

41 But see the exception in s 761E(6) of the *Corporations Act*.

42 See also s 911D of the *Corporations Act* which effectively provides that a financial services business is taken to be carried on in a jurisdiction by a person if, in the course of carrying on the business, the person engages in conduct which induces or is intended to induce people in the jurisdiction to use the financial services which the person provides.

43 For the penalty for this offence see ss 1311 and 1312 of the *Corporations Act*, Sched 3 to the *Corporations Act* and s 4AA of the *Crimes Act* 1914 (Cth).

Prior to the current Ch 7 of the *Corporations Act* being inserted, most electricity industry participants were regulated by the futures industry provisions in the former Ch 8 of the *Corporations Act* (and its predecessor legislation). Under the former s 1123, entities were prohibited from conducting an "unauthorised futures market". The general view was that many electricity derivative contracts were "futures contracts" for the purposes of the *Corporations Act* (and its predecessor legislation) and thus most parties to these contracts needed to be a party to an "Exempt Futures Market Declaration" in order to avoid breaching the above prohibition. Most electricity industry participants were a party to the *Corporations (Exempt Futures Market – National Wholesale Electricity) Declaration 1999*.

Under the transitional provisions in Ch 10 of the *Corporations Act*, entities who were a party to an Exempt Futures Market Declaration before the current Ch 7 of the *Corporations Act* came into effect on 11 March 2002 are able to continue entering into transactions (of the same kind as they entered into prior to that date) for a transitional period of two years before they will need to hold an AFS Licence.[44]

Is the Contract a Derivative?

In light of the above, the first issue to determine is whether a given contract which involves the sale of RECs (and possibly other Green Rights) is a "derivative" for the purposes of the *Corporations Act*.

The word "derivative" has an expanded meaning in the *Corporations Act* and is defined in s 761D of the *Corporations Act* and Reg 7.1.04 of the *Corporations Regulations*. Subsection 761D(1) effectively provides that, for the purposes of the *Corporations Act*[45] and subject to subss 761D(2), (3) and (4), a "derivative" is an arrangement in relation to which the following conditions are satisfied:

(a) under the arrangement, a party to the arrangement must, or may be required to, provide at some future time consideration of a particular kind or kinds to someone; and

(b) that future time is not less than the number of days, prescribed by regulation, after the day on which the arrangement is entered into [Reg 7.1.04(1) provides for a minimum time period of three business days for a spot foreign exchange contract and one business day in any other case]; and

(c) the amount of the consideration, or the value of the arrangement, is ultimately determined, derived from or varies by reference to (wholly or in part) the value or amount of something else (of any nature whatsoever and whether or not deliverable), including, for example, one or more of the following:

44 See, in particular, ss 1430 and 1431 of the *Corporations Act.*

45 The wording in s 761D of the *Corporations Act* suggests that the definition of "derivative" in s 761D only applies for the purposes of Ch 7 of the *Corporations Act*. However, s 9 of the *Corporations Act* provides that the word "derivative" has the same meaning in the remainder of the *Corporations Act.*

(i) an asset;
(ii) a rate (including an interest rate or exchange rate);
(iii) an index;
(iv) a commodity.

Subsection 761D(3) effectively provides that, subject to subs 761D(2), the following are not derivatives for the purposes of the *Corporations Act* even if they are covered by the definition in subs 761D(1):

(a) an arrangement in relation to which subparas (i), (ii) and (iii) below are satisfied:
  (i) a party has, or may have, an obligation to buy, and another party has, or may have, an obligation to sell, tangible property (other than Australian or foreign currency) at a price and on a date in the future; and
  (ii) the arrangement does not permit the seller's obligations to be wholly settled by cash, or by set-off between the parties, rather than by delivery of the property; and
  (iii) neither usual market practice, nor the rules of a licensed market or a licensed CS facility, permits the seller's obligations to be closed out by the matching up of the arrangement with another arrangement of the same kind under which the seller has offsetting obligations to buy;

  but only to the extent that the arrangement deals with that purchase and sale;
(b) a contract for the future provision of services;
(c) anything that is covered by a paragraph of subs 764A(1), other than para (c) of that subs [para (c) of subs 764A(1) refers to a derivative and the remainder of subs 764A(1) is not relevant to RECs and Green Rights transactions];
(d) anything declared by the regulations not to be a derivative for the purposes of Ch 7 [the regulations have not made such a declaration].

Subsection 761D(4) effectively provides that, subject to subs 761D(2), an arrangement under which one party has an obligation to buy, and the other has an obligation to sell, property is not a derivative for the purposes of the *Corporations Act* merely because the arrangement provides for the consideration to be varied by reference to a general inflation index such as the Consumer Price Index. "Property" is broadly defined in s 9 of the *Corporations Act* to mean any legal or equitable estate or interest (whether present or future and whether vested or contingent) in real or personal property of any description and includes a thing in action. RECs and Green Rights come within this definition.

Subsection 761D(2) effectively provides that, without limiting subs 761D(1), anything declared by the regulations to be a derivative for the purposes of s 761D is a derivative for the purposes of the *Corporations Act*. A thing so declared is a derivative despite anything in subss 761D(3) and (4).

Regulation 7.1.04 declares certain arrangements to be derivatives for the purposes of subs 761D(2). The wording used in Reg 7.1.04 is very similar in effect to the wording used in subss 761D(1), (3) and (4). As a result, the arrangements which are derivatives as a result of the combined application of subs

761D(2) and Reg 7.1.04 are mostly the same arrangements which are derivatives as a result of the combined application of subss 761D(1), (3) and (4).[46]

There are a number of effects of the above provisions. Firstly, if a transaction involving the sale of RECs or RECs and other Green Rights also includes a swap (as described above) where the floating amount payable is a function of the spot price in the NEM then that transaction will be a derivative for the purposes of the *Corporations Act*. Secondly, a transaction involving the sale of RECs (with or without a sale of Green Rights and electricity) in the future where the price is affected by an index (other than a general inflation index such as the CPI) or by some other price or rate will arguably be a derivative for the purposes of the *Corporations Act*.[47] Thirdly, a transaction involving the sale of RECs (with or without a sale of Green Rights and electricity) where the price payable is not affected by an index other than a general inflation index such as the CPI will not be a derivative for the purposes of the *Corporations Act*.

Insider Trading

If a party to a transaction is subject to the *Corporations Act* and the transaction is a derivative then the party needs to take into account the effect of the insider trading provisions in Div 3 (being ss 1042A to 1044A) of the *Corporations Act*. The prohibition is contained in s 1043A and, in so far as it applies to derivatives, effectively provides that if:

(a) a person (defined for the purposes of the s as the "insider") possesses "inside information" (defined in s 1042A as information which is not generally available and which, if it were so available, a reasonable person would expect to have a material effect on the price or value of a derivative); and
(b) the insider knows or ought reasonably to know that the inside information is not generally available and that if it were so available then a reasonable person would expect that information to have a material effect on the price or value of a derivative,

then the insider must not "apply for", "acquire" or "dispose of" derivatives (or enter into an agreement to do so) or procure another person to apply for, acquire or dispose of derivatives (or enter into an agreement to do so). When a party enters into a derivative it is "acquiring" a derivative for the purposes of the above prohibition.

[46] The differences are the exclusion of spot foreign exchange contracts in para (a) of subreg 7.1.04(2), the difference between the time period specified in para (b) of subs 761D(1) (when combined with subreg 7.1.04(1)) and the time period specified in para (b) of subreg 7.1.04(2) and the absence in Reg 7.1.04 of an equivalent provision to para (d) of subs 761D(3).

[47] There is an alternative argument that RECs and Green Rights which result in a certificate being created are "tangible property" for the purposes of para 761D(3)(a) of the *Corporations Act*, in which case they would come within the exemption in that paragraph if the other requirements of that paragraph are satisfied.

It can be argued that the prohibition has been drawn too widely with the result that electricity industry participants will, in all likelihood, be in possession of inside information at the time of entering into a derivative and it will not be practical for them to act in a manner which takes advantage of the exemptions from liability contained in the *Corporations Act*. However, the above issue is complex and it is beyond the scope of this paper to consider the issue in any detail.[48]

DOCUMENTING TRANSACTIONS INVOLVING RECS AND OTHER GREEN RIGHTS

Issues to Include in a Contract for the Sale of RECs Only

As stated above, some contracts involve a simple sale and purchase of RECs. However, even in such a simple contract, there are a variety of options for the parties to choose between both in relation to the nature of the RECs and the timing of their delivery.

Nature of RECs sold

In relation to the nature of the RECs, the contract might provide for the delivery of a specified quantity of RECs, the delivery of a specified quantity of RECs created in relation to electricity generated from a particular fuel source or the delivery of specific RECs identified by their unique identification numbers.

The contract might also require the RECs to have been created on or before 31 December in a given year – as, under the MRET Scheme, the RECs which a buyer surrenders on 14 February need to have been created in the previous year.

Timing of delivery

In relation to the timing of delivery, the contract might provide for delivery on or about the date of the contract, delivery of one parcel of RECs at some time in the future or delivery of a number of parcels of RECs with each parcel being delivered on a separate delivery date in the future.

As discussed above, if a buyer wishes to surrender RECs in respect of a given calendar year, the buyer needs to have acquired those RECs before 14 February in the next year. The delivery date in any contract needs to be set so that the buyer obtains its RECs in time to surrender them on 14 February.

What does "delivery" mean?

The concept of "delivery" of RECs needs to be defined. As RECs are not tangible property they cannot be physically delivered from one person to the other

48 There is some discussion of the issue on the website of the Corporations and Markets Advisory Committee (CAMAC) – http://www.camac.gov.au/.

or from one place to the other. As a practical matter, they are transferred from the seller to the buyer by each of the seller and the buyer contacting the Regulator under the REC Act and instructing the Regulator to transfer the registration of the RECs from the seller's name to the buyer's name.[49] There may be some time delay between the time that the Regulator receives these instructions and the time of registration.

"Delivery" could be defined to be the moment of registration. However, "delivery" could also be defined to be the time when the seller has performed or caused to be performed all steps required of a transferor under the REC Act to cause that REC to be transferred to the buyer (including any mandatory notification of the transfer by the transferor required under the REC Act). This is the approach that has been taken by AFMA[50] in the standard ISDA[51] documents which AFMA provides for use by industry participants.

One issue which needs to be negotiated between the seller and the buyer is the timing of the delivery/registration of the transfer relative to the time of payment. Delivery/registration before the buyer pays the purchase price benefits the buyer by eliminating the risk of paying for RECs that are not subsequently delivered/registered but exposes the seller to the risk of parting with RECs for which it does not receive payment. Payment before delivery/registration transfers the risk from the seller to the buyer.[52]

Transfer of title

Further, while a buyer cannot (as a practical matter) deal with a REC until the transfer is registered in its name, the registration of a transfer under the REC Act does not actually confer title on the buyer. The moment when title is transferred needs to be specified in the contract. Depending on the approach which the parties take to the issues in the previous paragraph, the contract could provide for title to be transferred upon registration of the transfer.

49 But see the discussion below in relation to the transfer of title.

50 The Australian Financial Markets Association.

51 ISDA stands for International Swaps and Derivatives Association Inc. The "ISDA documents" are, strictly speaking, the various documents published by ISDA which together form a framework for documenting various spot and forward commodity transactions. However, this term is often used to include the various AFMA documents which have been published for use in conjunction with the documents prepared by ISDA. The definition of "delivery" referred to above appears in the document titled *June 1997 Australian Addendum No 13 (as amended in April 2002) – Electricity (Energy and REC) Transactions*, being a document published by AFMA for use as an addendum to the ISDA Master Agreement.

52 There is a similar discussion of this issue in T Reginato, "What are the legal implications for trading renewable energy certificates using non-ISDA based agreements?" *Electricity Supply Magazine* (March 2002), p 25.

Liability for fees and charges

One issue for the parties to address is who will be liable for any taxes, fees and charges which are payable in respect of the registration of the transfer of the REC (and possibly its earlier creation and the registration of that creation).

Warranties

A buyer is likely to seek the following warranties from the seller:

(a) a warranty that, prior to the time of transfer of the REC to the buyer, the REC was created and registered in accordance with the relevant provisions of the REC Act;

(b) a warranty that, at the time of transfer of the REC to the buyer, the seller is the registered owner of the REC and owns full legal and beneficial title to the REC and the REC is not subject to any charge or other encumbrance;

(c) if a term of the contract requires the RECs to have been created in relation to electricity generated from a particular fuel source – a warranty that the RECs were created in relation to electricity generated from that fuel source; and

(d) if a term of the contract requires the RECs to have been created by a certain date – a warranty that the RECs were created by that date.

Each party is also likely to seek a warranty from the other party that:

(a) the other party is duly incorporated or is established under legislation, validly exists and has the capacity to sue and be sued in its own name;

(b) the execution of the contract and the performance of the other party's obligations under the contract have been duly authorised by it and do not contravene any law or agreement binding on it or its constitution; and

(c) the contract is valid, binding and enforceable in accordance with its terms.

Indemnity

The buyer might also seek an indemnity from the seller for its costs of the seller's default in failing to deliver the required quantity and type of RECs by the delivery date subject to a cap equal to the renewable energy shortfall charge.

ISDA or non-ISDA

The above transaction could be easily documented using either an ISDA or a non-ISDA document. A discussion of the relative merits of ISDA and non-ISDA documents is contained in a later s of this paper.

Delivery and the ISDA Master Agreement

If the transaction is documented using an ISDA document then it is appropriate to amend the terms of the Master Agreement so that the various references to "payment" also include "delivery". This change is effected by the provisions of *June 1997 Australian Addendum No 13 (as amended in April 2002) – Electricity (Energy and REC) Transactions* which (as discussed below) is typically incorporated into ISDA based RECs transactions.

Issues to Include in a Contract Which Also Involves the Sale of Green Rights and Either an Electricity Sale or an Electricity Derivative Transaction

As stated above, GenCo is more likely to enter into a transaction which is either:

(a) a sale of all or part of the electricity generated by the power station during a defined Generation Period together with a sale of all or defined categories of Green Rights associated with that electricity; or

(b) an electricity derivative transaction (where the notional quantity on which the fixed and floating amounts are calculated equals all or a fixed percentage of the electricity generated by the power station during a defined Generation Period) together with a sale of all or defined categories of Green Rights associated with that electricity.

A number of risks arise in relation to the production of electricity and Green Rights and the PPA should be drafted to address how these risks will be allocated between GenCo and BuyCo (or, from the financier's perspective, between the financier and BuyCo). These risks are discussed in the paragraphs below.

Fluctuating quantity of electricity

The first risk is the risk associated with a fluctuating quantity of electricity which is produced by the power station. The amount of electricity which a power station generates will depend on the amount of time that the power station needs to be taken out of service for repairs and maintenance, the amount of fuel that is available to operate the power station and whether GenCo operates the power station at all times when it is capable of being operated and has sufficient fuel.

Typically, a PPA which involves the sale of electricity will provide that the amount paid by BuyCo varies according to the quantity of electricity generated and sold to BuyCo. This protects BuyCo from the risk of paying for electricity which it does not receive.

Under the above scenario, GenCo will the bear the risk associated with lost production due to the power station not being able to be operated. To the extent that this arises due to the acts or omissions of those involved in the construction or operation of the power station, GenCo may be able to pass on some of this liability to those persons under its construction and operation and maintenance contracts.

Not all financiers will be happy for GenCo to bear the risk of insufficient fuel and may require GenCo to find a purchaser who is prepared to guarantee a minimum payment to GenCo irrespective of the amount of electricity produced. The payment would be conditional on the power station being capable of being operated if sufficient fuel existed. In such a scenario, BuyCo would effectively be paying for the availability of the power station. This is unlikely to be an attractive proposition for BuyCo. An alternative option would be for GenCo to bear this risk and to seek a guaranteed supply of fuel from its fuel suppliers and to seek compensation if fuel is not supplied.

Assuming that GenCo does not receive a guaranteed minimum payment under the PPA, GenCo will bear the cost of lost production due to not operating the power station for other reasons. One such reason is network constraint. In theory, GenCo can seek some guaranteed level of export capability on to the local network in its connection agreement with the local network service provider. However, in practice, the local network service provider will be hesitant to commit to guaranteed levels of export capability given the practical need to be able to operate its network to cater for the needs of all who are connected and to comply with any operating instructions from NEMMCO. Network service providers need to bear in mind the requirements of the Code relating to the terms of connection agreements.

If BuyCo is the Local Retailer under the Code, BuyCo is likely to have set the price at which it sells electricity by reference to the expected quantity (and price) of electricity that it will receive under the PPA with GenCo and under other PPAs. If the actual quantity received is less than expected then BuyCo will need to purchase additional electricity either in the spot market at the spot price or under other PPAs (possibly at a higher price than under the PPA with GenCo).

BuyCo is therefore exposed to the risk that the spot price or the fixed price under the additional PPAs will be higher than the fixed price under the PPA with GenCo. To minimise its risk, BuyCo may seek to incorporate terms in the PPA which give it some influence on the manner in which the power station is operated – such as the need for GenCo to seek BuyCo's consent for maintenance outages or changes in fuel source. BuyCo may also seek to insert penalties into the PPA to give GenCo a commercial incentive to deliver the forecast quantities of electricity. BuyCo should also require GenCo to be a party to a connection agreement with the local network service provider which permits the whole of the output of the power station to be exported to the local network.

If the PPA takes the form of an electricity derivative transaction where the notional quantity corresponds to the actual metered output (or a fixed percentage of that output – perhaps where GenCo has entered into electricity derivative transactions with a couple of counterparties to cover the whole output) then BuyCo is exposed to the risk of the level of hedging cover not matching the level of cover which it needs to supply its customers. There is little that BuyCo can do to reduce this risk. The rationale for matching the notional quantity with the actual metered output is to provide GenCo with perfect hedging cover in relation to its output (which in this scenario would be being sold by GenCo to NEMMCO in the NEM or to the Local Retailer at the spot price). GenCo in this situation will bear the risk of lost revenue associated with the power station not being able to be operated or having insufficient fuel.

Fluctuating quantity of Green Rights

The second risk is the risk associated with the fluctuating quantity and types of Green Rights which are created in relation to the electricity which is generated. The amount and type of Green Rights will depend on the amount and type of

Green Rights which the various Commonwealth and State regulatory regimes permit to be created at any given time, whether GenCo obtains all the necessary registrations, licences, accreditations and other authorisations to create the various types of Green Rights and whether GenCo uses its best efforts to maximise the number and types of Green Rights created.

The risk of a fluctuating number and type of Green Rights can affect BuyCo in two ways.

Firstly, if BuyCo has paid a fixed price for a bundle of Green Rights associated with a given quantity of electricity then BuyCo is exposed to the risk that the number and type of Green Rights created will have a value which is less than the price paid.

Secondly, if BuyCo has entered into transactions in the expectation of receiving a certain number and type of Green Rights to enable it to comply with the various regulatory regimes and to satisfy obligations in its contracts with customers (to source electricity from certain "green" sources) then BuyCo is exposed to the risk of those Green Rights not eventuating and having to buy additional Green Rights from other sources later in time (and, in all likelihood, at a higher price) to satisfy its obligations or simply being unable to satisfy those obligations.

BuyCo could remove the first risk by only paying for those Green Rights actually received. However, that would transfer the risk associated with fluctuations in the Green Rights produced back to GenCo. That result is unlikely to be acceptable to financiers – while financiers will generally accept operational risks and perhaps fuel risks, they will rarely accept risks associated with variations in the regulatory regime which lead to fluctuations in the Green Rights produced. Therefore, BuyCo is unlikely to be able to negotiate a transaction (at least in the case of a new power station) under which it only pays for Green Rights which it receives.

A scenario where BuyCo pays a fixed price for a bundle of Green Rights is therefore the most likely. The risk being absorbed by BuyCo is likely to be factored into the bundled price such that the bundled price is less than the sum of the individual prices of Green Rights which are foreseen at the time of negotiation of the contract.

A possible variation on the above which may be possible is to insert a provision under which the bundled price drops to a lower amount if certain thresholds of electricity production or Green Right production are not met.

If BuyCo is paying a bundled price for whatever Green Rights it receives, it should seek to minimise its risk by inserting a variety of contractual obligations into the contract to maximise the value of the Green Rights which are produced. These include:

(a) defining "Green Rights" as broadly as possible in order to take advantage of any future regulatory schemes which create new types of Green Rights;

(b) imposing an obligation on GenCo to obtain all necessary registrations, licences, accreditations and other authorisations to create the various types of Green Rights;

(c) imposing an obligation on GenCo to create a certain type (or types) of Green Rights and as many of these Green Rights as possible from the quantity of generated electricity – this could be an absolute obligation or merely an obligation to use best or reasonable endeavours;

(d) expanding the above obligation by adding an obligation to make such Green Rights in accordance with the requirements of the relevant regulatory regime. GenCo is likely to seek to reduce this obligation to only apply until the regulatory regime is changed or to make BuyCo compensate it for the additional costs of complying with any changes to the regulatory regime; and

(e) imposing an obligation to enter into a connection agreement with the local network service provider which enables the entire output of the power station to be exported to the local network (as an inability to export electricity – given that electricity cannot be stored – will prevent electricity and Green Rights from being produced).

The parties also need to address the timeliness of the creation and transfer of Green Rights to maximise the value to BuyCo of the Green Rights which it receives. As discussed above, RECs need to be transferred to BuyCo before 14 February in each year otherwise they cannot be used by BuyCo (other than for on-selling) until the next year's compliance. As also discussed above, NGACs cannot be created more than six months after the end of the year in which the electricity was generated and the NGACs need to be transferred to BuyCo before 1 March in each year otherwise they cannot be used by BuyCo (other than for on-selling) until the next year's compliance.

The PPA needs to contain appropriate clauses to ensure that RECs and NGACs relating to a given quantity of electricity are created and registered in BuyCo's name within the above timeframes. Similarly, the creation and delivery of other Green Rights needs to be reasonably timely.

Other issues

A number of other issues should also be dealt with. These are discussed in the paragraphs below.

As briefly mentioned above, the parties need to address how any additional costs associated with regulatory change will be shared between them and how this will impact on the obligations relating to the creation of Green Rights. As GenCo is seeking a relatively guaranteed income to obtain finance, it is likely to seek to pass on the cost of regulatory change to BuyCo.

It is also preferable that the parties deal with how they will share any emissions permits which are able to be created if an emissions trading scheme is introduced.

The parties also need to deal with who will ultimately bear the cost of the various taxes, fees and charges which are associated with creating and registering (where applicable) the Green Rights, transferring the Green Rights and registering (where applicable) those transfers.

Sometimes the creation of one type of Green Right from a given unit of electricity could preclude the creation of another type of Green Right from that same unit (for example, as discussed above, for some fuel sources the creation of RECs precludes the creation of NGACs). The parties therefore need to address which types will be preferred to others. A good way of doing this is to provide a default position but to allow BuyCo to provide GenCo from time to time with a preferred order in which Green Rights are to be produced.

The parties also need to deal with a scenario where the power station is sold. GenCo will seek to give itself as much flexibility as possible. BuyCo will need to ensure that the PPA stays with the owner and operator of the power station in order to ensure that all of the obligations under the PPA can be performed. BuyCo also needs to ensure that it can veto any prospective assignee who doesn't have the financial standing or technical expertise to own and operate the power station.

The PPA is likely to give BuyCo rights of termination in various circumstances. It is likely that GenCo's financiers will attempt to obtain BuyCo's signature to a Deed under which BuyCo effectively agrees not to terminate the PPA before giving the financiers the opportunity to remedy any default of GenCo.

The parties need to ensure that appropriate metering exists to satisfy the requirements under the various regulatory schemes to create Green Rights as well as to comply with the requirements under Chapter 7 of the Code for electricity sold through the NEM. While GenCo will have contractual obligations under the PPA in relation to metering, it is likely that the metering will be provided by the local network service provider under the connection agreement or by a specialist metering provider.

ISDA OR NON-ISDA

An issue of contention in the industry is whether the above transactions should be documented using ISDA or non-ISDA documents. ISDA documents have their own unique structure and terminology. Therefore, for the benefit of readers who are unfamiliar with ISDA, it is appropriate to provide some brief background to the structure and language of the ISDA documents in the context of electricity derivatives, RECs transactions and other Green Rights transactions. As most parties are still using the 1992 version of the ISDA Master Agreement, the discussion in this paper relates to that version.

Background to the ISDA Documents

As stated above, "ISDA" stands for International Swaps and Derivatives Association Inc (formerly known as the International Swap Dealers Association).

ISDA produces a range of standard documents for use in a number of spot and forward commodity transactions.[53]

"AFMA" stands for the Australian Financial Markets Association. AFMA has published a range of documents which contain suggested clauses and other documents for use with the ISDA documents in the context of Australian electricity derivative and REC transactions.[54]

When two parties decide to document transactions between them using the ISDA documents, they generally first enter into an "ISDA Master Agreement". That Master Agreement contains terms which apply to all subsequent transactions between them. Each transaction is then documented using a document known as a "Confirmation". The Confirmation sets out the terms that are specific to that transaction.

As a matter of law, the sum of the Master Agreement and the various Confirmations constitute the one combined legal contract. Each transaction therefore constitutes an amendment to the terms of the existing contract rather than a separate contract in its own right. It is therefore a little misleading to refer (as we often do) to each separate transaction as being a separate "contract".

When we speak of "termination" under ISDA we mean termination of one or more transactions rather than termination of the combined contract containing the Master Agreement. However, in most circumstances where one transaction is terminated, the other transactions will also be terminated. This will result in the Master Agreement remaining in existence but there being no transactions.

The "ISDA Master Agreement" or "Master Agreement" (in the broad sense of the word) itself contains a number of documents. The first document is the "ISDA Master Agreement" (in the narrow sense of the word).[55] This contains various standard terms. It is contemplated in this document that the parties entering into this Master Agreement will wish to make their own variations to the terms of the Master Agreement and will also need to insert details relevant to themselves for the purposes of the application of the Master Agreement. These variations and additional information are included in a Schedule attached to the back of the ISDA Master Agreement (hence it is known as the "Schedule to the Master Agreement").

It is possible to annex further documents to the Master Agreement. Parties to electricity derivative and RECs transactions typically annex the document known as *June 1997 Australian Addendum No 13 (as amended in April 2002) – Electricity (Energy and REC) Transactions*. This has been published by AFMA. For ease of reference it will be referred to in this paper as "Addendum 13". Addendum 13 incorporates into the Master Agreement the terms of two further documents published by ISDA – being the *2000 ISDA Definitions* and the *1993 ISDA Commodity Derivatives Definitions*.

53 See the ISDA website – http://www.isda.org/.

54 See the AFMA website – http://www.afma.com.au/.

55 Most counterparties have been using the June 1992 edition of the *Multicurrency – Cross Border ISDA Master Agreement*. In January 2003, ISDA released a new version of the Master Agreement titled the *2002 ISDA Master Agreement*. This document contains a number of improvements on the *1992 ISDA Master Agreement*.

Netting

The ISDA Master Agreement allows for netting to occur between transactions covered by the same Master Agreement. Netting occurs in two scenarios. The first is where amounts which are payable on a given day under one transaction are netted against amounts which are payable on that day under all other transactions between the parties under that Master Agreement and only the net amount is payable (s 2(c) 1992 ISDA Master Agreement).

The second and more significant scenario is where some (or, most likely, all) of the transactions under the Master Agreement are terminated early. The Master Agreement provides in s 6(e) a "close-out" mechanism which calculates termination values for all terminated transactions under the Master Agreement and nets those values against each other. One circumstance which will trigger the early termination of all transactions and the close-out mechanism is the insolvency of one party (s 5(a)(vii) ISDA Master Agreement). The netting of the respective amounts prevents a liquidator from being able to "cherry-pick" between the transactions leaving a party to perform some transactions but to prove in the liquidation of the insolvent party for the other transactions.

No such netting exists between transactions which are separately documented using "non-ISDA" contracts.

Calculation of the Termination Values for Each Transaction

Overview

When a transaction is terminated early, both parties are likely to enter into separate replacement transactions with third parties. It is likely that prices will have changed between the time that the original transaction was entered into and the time that the replacement transaction is entered into. As a result, one party will find that the new transaction comes at a more favourable price and the other party will find that the new transaction comes at a less favourable price. In that sense, one party makes a "windfall gain" and one party makes a "loss" from the early termination.

When a transaction is documented under ISDA (and ignoring the effect of any netting against other transactions), the party who benefits from the early termination generally makes an "early termination payment" to the party who suffers a loss from the early termination irrespective of who was at fault in causing the termination. At the risk of being overly simplistic, the early termination payment is substantially designed to compensate the "losing party" for the loss suffered and effectively involves the "gaining party" giving up its windfall gain.

By contrast, under a non-ISDA contract, compensation is only paid if the party who suffers the loss was the non-defaulting party. In such a case, the payment is made by the defaulting party (following a claim by the non-defaulting party for "damages" for breach of contract). However, if the defaulting party is the one who suffers the loss and the non-defaulting party makes a windfall gain then the loss and the gain lie where they fall and no adjustment payment is made between the parties.

It is valid to ask whether it is correct (from a policy perspective) for a non-defaulting party under ISDA-documented transactions relating to the electricity industry to always be required to compensate a defaulting party for its losses arising from early termination. If not then either the early termination provisions should be rewritten or the transactions should be documented using non-ISDA documents which do not have such early termination provisions.

Detailed explanation

If a transaction is terminated early under the ISDA documents then we refer to an "Early Termination Date" being designated by one of the parties. An Early Termination Date can be designated following the occurrence of an "Event of Default" or a "Termination Event" (ss 6(a) and (b) ISDA Master Agreement).

Events of Default are set out in detail in s 5(a) of the Master Agreement. In very broad terms, Events of Default include:

(a) breach by a party of an obligation under a transaction or the Master Agreement;[56]
(b) certain defaults by a party, its guarantors or other related entities under certain types of transactions with third parties;[57]
(c) misrepresentation;[58]
(d) a party becoming insolvent; and[59]
(e) a party being restructured in a way which reduces the assets or credit support available to support its obligations to the other party.[60]

Termination Events are set out in detail in s 5(b) of the Master Agreement. In very broad terms, Termination Events include:

(a) a change in law making it illegal for a party to make a payment under a transaction;[61]
(b) certain tax changes which affect payments made between the parties under a transaction;[62]
(c) a party being restructured in a way that has certain tax consequences or reduces its creditworthiness; and[63]

56 These breaches fall into two categories – "Failure to Pay or Deliver" (which applies to failures to make payments or deliveries and which must be cured within three Local Business Days of notice of the failure) and "Breach of Agreement" (which applies to other breaches and which must be cured within 30 days of notice of the failure).
57 Known as "Credit Support Default" and "Default under Specified Transaction".
58 Known as "Misrepresentation".
59 Known as "Bankruptcy" – which has an extensive definition.
60 Known as "Merger Without Assumption".
61 Known as "Illegality".
62 Known as "Tax Event".
63 Known as "Tax Event Upon Merger" and "Credit Event Upon Merger".

(d) any other events agreed between the parties to be "Additional Termination Events" (for example, failure to comply with a request to provide additional credit support).

If one party (Defaulting Party) commits an Event of Default then the other party (Non-Defaulting Party) can designate an Early Termination Date for all outstanding transactions between the parties under the Master Agreement.

If a Termination Event occurs then one or both parties (depending on which Termination Event occurs) has a right to designate an Early Termination Date for all transactions between the parties under the Master Agreement which are affected by that Termination Event (s 6(b) 1992 ISDA Master Agreement). Often, all of the transactions between the parties are so affected.

The early termination payment between the parties is typically calculated using the "Second Method" and "Market Quotation".[64] This generally involves the payment of "Unpaid Amounts" which became owing prior to the Early Termination Date as well as a "Settlement Amount".[65]

For Events of Default, the Settlement Amount is determined by the Non-Defaulting Party and is based on "Market Quotations"[66] for the terminated transactions. The calculation of Market Quotations is discussed further below. However, they are essentially designed to reflect the gain or loss to the Non-Defaulting Party of entering into replacement transactions for the terminated transactions.

For Termination Events, one party is usually the "Affected Party" (that is, the party "at fault") and the other party is the "non-Affected Party". Occasionally, both parties are Affected Parties. If there is one Affected Party then the non-Affected Party determines the Settlement Amount based on Market Quotations. If there are two Affected Parties then each party determines its own Settlement Amount based on Market Quotations and the average is taken and paid between them. (See s 6(b) and the definitions of "Market Quotation" and "Settlement Amount" in the 1992 ISDA Master Agreement.)

In essence, the above mechanism essentially results in the party who receives the windfall gain due to the early termination compensating the other party for the loss suffered by the other party due to the early termination, irrespective of which party was "at fault" in causing the early termination. The size of such a payment could be quite significant (thus creating a liquidity issue for the payer) and the Non-Defaulting/non-Affected Party has a valid argument that it should not be exposed to the risk of suffering the detriment associated with making such large payments due to events which were not of its making.

[64] There are four choices under s 6(e) of the *1992 ISDA Master Agreement* – "First Method and Market Quotation", "First Method and Loss", "Second Method and Market Quotation" and "Second Method and Loss".

[65] These expressions are defined in s 14 of the *1992 ISDA Master Agreement*.

[66] This expression is defined in s 14 of the *1992 ISDA Master Agreement*.

The above situation could be addressed by replacing the "Second Method" with the "First Method" so that the party not "at fault" does not have to compensate the party "at fault" for its losses. However, this change would cause the Master Agreement to no longer be a "close-out netting contract" for the purposes of the *Payment Systems and Netting Act* 1998 (Cth). Various other conditions would then need to be satisfied to ensure that the netting provisions in the Master Agreement remain effective. However, these issues are beyond the scope of this paper.[67]

The Enron case

The decision in *Enron Australia Finance Pty Ltd (in Liq) v Integral Energy Australia*,[68] has raised doubts about the correct method of calculating the Market Quotation under the standard Australian ISDA documents.

By way of background, the standard documents provide for the selection of four "experts". Each expert then has to provide a Market Quotation - being a quotation of the amount that would hypothetically be paid between it and the relevant party to enter into a replacement transaction for that portion of the terminated transactions which relates to the period after the Early Termination Date.

Let us call the parties to a typical electricity derivatives transaction the "Seller" and the "Buyer" – the Seller being the party who pays the floating price and the Buyer being the party who pays the fixed price. The price at which a person would offer to be the Seller in such a transaction will differ from the price at which the same person would offer to be the Buyer. This difference is known as the "bid-offer spread". The price at which the parties to a transaction ultimately trade is known as the "market price". It is arguable that under the ISDA documents, the correct amount to be used for the Market Quotation is the amount that would be offered on the relevant side of the above bid-offer spread – that is, if the expert is considering a case where it would be a Seller then it should quote the selling price and if the expert is considering a case where it would be a Buyer then it should quote the buying price. However, the NSW Supreme Court in the *Enron* case said that the correct amount to be quoted is the market price.

Familiarity, complexity and standardisation

One argument advanced in favour of using ISDA documents for RECs transactions is that it assists to standardise the documentation for such transactions. The use of standardised documents leads to cost efficiencies and increases the liquidity and depth of the market.[69]

[67] A discussion of the law of "netting" is beyond the scope of this paper. See the discussion of this issue in the context of the ISDA Master Agreement in Pts 3, 17 and 23 of AFMA's *Guide to OTC Documents*. This is available by subscription from AFMA's website – http://www.afma.com.au/.

[68] *Enron Australia Finance Pty Ltd (in Liq) v Integral Energy Australia* [2002] NSWSC 753 (3 September 2002), Einstein J.

[69] K Farrow, "Renewable energy certificates and ISDA: the debate continues" *Electricity Supply Magazine* (June 2002), p 19.

Whether or not the latter argument is true, the use of the ISDA documents will assist to standardise the documentation for certain types of transactions. Where a transaction is an electricity derivative then the ISDA documents are entirely appropriate. Where a transaction is a simple spot or forward sale of either a specified quantity of RECs or certain identified RECs then the ISDA documents can be used without great difficulty (although non-ISDA documents in this context are also relatively straightforward).

If a party wishes to take advantage of the netting provisions in the ISDA documents and the party is happy with the early termination provisions under ISDA then the use of ISDA documents would be the preferable choice. However, if the party wishes to provide for different termination consequences and is not concerned with netting then the use of a non-ISDA document would be the preferable choice (as it would avoid the need to "undo" the complex early termination payment provisions in the Master Agreement).

Further, the perceived advantages of using ISDA documents either do not apply or are significantly diminished in the case of sales of Green Rights involving a range of obligations (as discussed above) relating to using best endeavours to maximise the number and type of Green Rights created and an obligation to transfer whatever Green Rights are produced. The terms of such a transaction deal with issues not covered by the Master Agreement and require large amounts of often complex drafting. Further, many of the terms of the ISDA Master Agreement simply do not apply to such a transaction. The terms of such a transaction are therefore not "standard" or simple.

This situation is compounded if the parties choose to adopt an early termination payout mechanism which is different from "Second Method" (discussed above) as drafting amendments to the ISDA Master Agreement to adjust the early termination payments is a complex exercise that should not be undertaken by anyone who does not have a detailed understanding of the workings of these provisions under the ISDA Master Agreement.

This is not to say that such transactions cannot be documented under ISDA. Indeed, where the Green Rights sale is combined with an electricity derivative transaction and it is desired to keep all of the obligations in the one transaction then it is necessary to document the transaction under ISDA. However, where the Green Rights sale is not combined with an electricity derivative then it would be preferable to use a non-ISDA agreement.

Another argument used in support of ISDA documents is that parties are familiar with them and understand them. In the writer's experience, this is simply not the case. The level of complexity of the Master Agreement (including the number of documents it comprises and the complexity of the early termination provisions) is such that only a small number of industry participants understand the full impact of the various provisions. This lack of understanding leads to a significant difficulty when industry participants try to substantially amend the ISDA documents to suit a particular transaction without appropriate specialist legal advice. Almost inevitably, the well-intentioned draftsperson inadvertently triggers a whole range of unintended consequences.

Conditions precedent to delivery

It is also necessary to note that the effect of s 2(a)(i) and (iii) of the Master Agreement is that a party's obligation to make a payment or delivery under a transaction is subject to (among other things) the condition precedent that no Event of Default with respect to the other party has occurred and is continuing. The effect of s 5(a)(ii) of the Master Agreement is that a default which is unremedied for 30 days after notice of the default is an Event of Default. In a Green Rights transaction between GenCo and BuyCo involving a range of obligations, it would not be too difficult to identify a default by a party which permitted the other party to cease making payments and deliveries. Such a result would not occur under a non-ISDA contract. Query whether such a result is desirable.

In summary, whether or not the ISDA documents are appropriate depends on the type of transaction (be it a sale of electricity, an electricity derivative or a sale of Green Rights), the consequences that the parties are trying to achieve (particularly in relation to their respective liabilities should the transaction terminate early) and generally how far the terms of the transaction will deviate from the standard terms in the ISDA documentation.

CONCLUSION

The introduction of the MRET Scheme and other schemes to encourage the generation of electricity from renewable energy sources has led to the development of a number of renewable energy power stations over the last couple of years. Each of these schemes has sought to increase the value of the output of such power stations by creating additional forms of property (often referred to as "Green Rights") which are able to be sold for value independently of the electricity. When the *Renewable Energy (Electricity) Amendment Bill* 2002 (Cth) comes into effect, it will correct a number of minor teething problems which have been found in the MRET Scheme since its commencement.

The legal issues surrounding the sale of the output of such power stations are significant, complex and interrelated. The electricity can either be sold to NEMMCO in the NEM, to the Local Retailer or to a third party who will, in turn, on-sell the electricity to either NEMMCO or to the Local Retailer. To facilitate the on-selling of the electricity to NEMMCO, the third party will be required to register under the Code as a Generator (as the Intermediary of the actual owner and operator of the power station). The third party will therefore become subject to the Code. Most industry participants who sell to NEMMCO will hedge their exposure to the NEM by entering into electricity derivative transactions. While RECs and other Green Rights created in relation to the generated electricity can, in theory, be sold on their own, it has been more typical for them to be sold in conjunction with the sale of the electricity or as part of an electricity derivative transaction. Entering into an electricity derivative transaction normally requires the party to obtain an AFS Licence under the *Corporations Act*. The party is also governed by the requirements of the *Corporations Act* (including the insider trading provisions).

Sales of RECs and Green Rights (in conjunction with a sale of electricity or an electricity derivative transaction) raise a number of commercial issues which need to be addressed. The parties need to allocate the risks arising from the uncertain quantity of electricity, RECs and Green Rights which will be created (due to operational, fuel supply, regulatory and other factors), bearing in mind the requirements of financiers. The parties also need to deal with timing issues for the delivery of Green Rights (to maximise the benefit to the purchaser) as well as the overlap between the various greenhouse schemes.

Parties to such transactions have often used the ISDA documents to record the terms of these transactions. It is also possible to use non-ISDA documents. The choice of document structure raises a number of issues and will depend on the type of transaction (be it a sale of electricity, an electricity derivative or a sale of Green Rights), the consequences that the parties are trying to achieve (particularly in relation to their respective liabilities should the transaction terminate early) and generally how far the terms of the transaction will deviate from the standard terms in the ISDA documentation.

SCHEDULE 1

Terms of Reference for the Review of the Renewable Energy (Electricity) Act 2000

The *Renewable Energy (Electricity) Act* 2000 establishes the Mandatory Renewable Energy Target which requires Australian electricity retailers and other large buyers of electricity to collectively source an additional 9,500 GWh of electricity per annum from renewable sources by 2010.

The Panel is to review the operation of the *Renewable Energy (Electricity) Act* 2000, to determine:

(a) the extent to which the Act has:
    (i) contributed to reducing greenhouse gas emissions; and
    (ii) encouraged additional generation of electricity from renewable energy sources; and
(b) the extent to which the policy objectives of this Act have been achieved and the need for any alternative approach; and
(c) the mix of technologies that has resulted from the implementation of the provisions of this Act; and
(d) the level of penalties provided under this Act; and

(e) the need for indexation of the renewable energy shortfall charge to the Consumer Price Index to maintain the real value of the charge and the associated penalty charge; and
(f) other environmental impacts that have resulted from the implementation of the provisions of this Act, including the extent to which non-plantation forestry waste has been utilised; and
(g) the possible introduction of a portfolio approach, a cap on the contribution of any one source and measures to recognise the relative greenhouse intensities of various technologies; and
(h) the level of the overall target and interim targets; and
(i) the appropriateness of the operating environment including the:
    (i) level of participation in and transparency of the Mandatory Renewable Energy Target measure; and
    (ii) scheduled end-date of 2020; and
    (iii) baselines for pre-existing generators; and
    (iv) need for future reviews; and
(j) the appropriateness of policy settings including the:
    (i) extent to which this Act has provided an ongoing basis for commercially competitive renewable energy; and
    (ii) relevant economic and social impacts that have resulted from the implementation of the provisions of this Act; and
    (iii) inclusion of renewable energy sources and technologies not specified in the Act or Regulations; and
    (iv) interaction with relevant Commonwealth, State and Territory energy, environment and industry policies.[70]

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[70] These terms of reference were attached to the joint media release by the Minister for the Environment and Heritage (Dr David Kemp) and the Minister for Industry, Tourism and Resources (the Hon Ian MacFarlane) dated 25 March 2003.