Development of an emission intensity index for the WEM

Initial advice

Prepared for the Independent Market Operator

29 March 2012

ACIL Tasman

Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)

Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane

Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra

Level 2, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth

Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney

GPO Box 4670
Sydney NSW 2001

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Owen Kelp
Telephone (07) 3009 8711
Mobile 0404 811 359
Email o.kelp@aciltasman.com.au

Contents

Contents ii

1 Introduction 1

2 Background 2

2.1 Clean Energy Future legislation 2

2.2 Emissions and emission scope 2

2.3 Implications for the WEM 4

2.4 Generator direct liabilities 4

2.4.1 Solid fuels 4

2.4.2 Gaseous fuels 6

2.4.3 Liquid fuels 7

2.5 Scope 3 emissions 8

2.5.1 Solid fuels 9

2.5.2 Gaseous fuels 9

2.5.3 Liquid fuels 10

3 What is an Emission Intensity Index? 12

3.1 What is it used for? 14

4 Development of an EII for the WEM 15

4.1 Data requirements 15

4.1.1 NGER data 15

4.1.2 Participant provided thermal efficiencies 17

4.1.3 IMO estimates 18

4.2 Index construction 19

4.2.1 Resolution 19

4.2.2 Inclusion or exclusion of Scope 3 emissions 20

4.3 Issues with use of EII for price pass-through 20

4.4 Index maintenance 20

4.5 Publication 21

5 Market consultation 22

List of boxes

Box 1 **Naming conventions** 1

List of figures

Figure 1 **AEMO's NEM Carbon Dioxide Equivalent Intensity Index** 13

List of tables

Table 1	**Fuel combustion emission factors – solid fuels and certain coal based products**	5
Table 2	**Fuel combustion emission factors – gaseous fuels**	6
Table 3	**Fuel combustion emission factors – liquid fuels and certain petroleum based products**	8
Table 4	**Scope 3 emission factors –solid fuels**	9
Table 5	**Australian natural gas Scope 3 emissions factors – 2011**	10
Table 6	**Scope 3 emission factors –liquid fuels**	10
Table 7	**Scope 2 and 3 emissions factors – consumption of purchased electricity by end users in the SWIS**	12
Table 8	**Published NGER totals for all corporations**	16

1 Introduction

ACIL Tasman has been engaged by the Independent Market Operator (IMO) to provide advice in relation to the development of an Emission Intensity Index (EII) for the Western Australian Wholesale Electricity Market (WEM).

The initial scope of work under this project is as follows:

- To provide background information explaining the concept of Emission Intensity Indices and how they are developed, calculated and used in electricity markets generally
- To provide advice on what data WEM generators have readily available (e.g. from NGERs reporting obligations, or other sources?)
- To provide advice on the merits of using Facility-based emission factors, or including fuel production and transport emissions as well
- To provide advice on what input data the IMO would need to collect from WEM participants to enable the IMO to calculate and publish a WEM Emission Intensity Index (to be used with generation data on a half-hour basis)
- To provide advice on what conversions and/or formulas the IMO would need to use to deliver a credible Emission Intensity Index.

This report represents the initial advice to the IMO on background issues and addressing the specific scope items above. It is envisaged that some of the material within this document will be utilised in a discussion paper for release to the market.

Box 1 **Naming conventions**

While somewhat pedantic, the terminology used within the greenhouse gas area is somewhat lacking – even within the Governments own documentation relating to the Clean Energy Future package. Within this report, we refer to 'Greenhouse Gas Emissions', often shortened to just 'Emissions' rather than the more general and more inaccurate term 'Carbon'. Thermal power stations do not emit carbon – they burn it and emit a range of gases, some of which are Greenhouse Gases.

Greenhouse Gases include Carbon dioxide (CO2), Methane (CH4), Nitrous oxide (N2O), Hydrofluorocarbons (HFCs) and Perfluorocarbons (PFCs). Each of these gases has an assigned Global Warming Potential (GWP) and are generally referred to in carbon dioxide equivalent terms (CO_2-e). This is achieved by multiplying the individual gas emission factor by the respective GWP (CO_2 has a GWP of one).

2 Background

2.1 Clean Energy Future legislation

The Australian Government Clean Energy Future (CEF) policy passed through parliament in November 2011. The key component of this measure is to introduce an explicit carbon pricing mechanism from 1 July 2012.

Businesses that are covered will pay a price for each tonne of carbon dioxide equivalent emissions each year. The mechanism will have two stages. The first, which will operate for the first three years, will operate under a fixed price, as in a carbon tax. The price will start at $23 per tonne on 1 July 2012. In each of the next two years, it will rise by 2.5% in real terms. Assuming inflation of 2.5% a year (the mid-point of the Reserve Bank of Australia's target range for inflation), the carbon price will be $24.15 per tonne in 2013-14 and $25.40 per tonne in 2014-15.

From 1 July 2015, the intention is to move to a cap and trade emissions trading scheme where an overall limit (or cap) will be placed on Australia's annual greenhouse gas emissions from all sources of pollution covered by the carbon price. From this date, the carbon price will no longer be fixed, but will be set by the market. The Government will set annual emission caps by issuing a fixed number of carbon permits each year.

Greenhouse gas emissions from stationary energy, waste, rail, domestic aviation and shipping, industrial processes and fugitive emissions will initially be covered under the scheme. It will cover four of the six greenhouse gases counted under the Kyoto Protocol — carbon dioxide, methane, nitrous oxide and perfluorocarbon emissions (from the aluminium sector). Therefore, over half of Australia's emissions will be directly covered by the carbon pricing mechanism.

Only firms that release over a certain amount of carbon pollution a year, or are large suppliers of natural gas, will pay the carbon price. Facilities that have direct greenhouse gas emissions of 25,000 tonnes of CO_2-e a year or more (excluding emissions from transport fuels and some synthetic greenhouse gases) will be covered.

2.2 Emissions and emission scope

There are a number of various terms used in the world of carbon accounting which are explained in the following section as they relate to emissions from the WEM. This material has been sourced from the Department of Climate

Change and Energy Efficiency, National Greenhouse Accounts Factors 2011 report.

Direct emissions are produced from sources within the boundary of an organisation and as a result of that organisation's activities. In the case of the WEM, these emissions mainly arise from the combustion of fuel to generate electricity; however these will also include other on-site emissions sources. These are referred to as **Scope 1 emissions**.

The principle greenhouse gas generated by the combustion of fossil fuels for electricity generation is carbon dioxide (CO_2). The amount of CO_2 produced depends on the carbon content of the fuel and the degree to which the fuel is fully combusted (i.e. the oxidation factor, which usually ranges between 98% and 99.5%). Small quantities of methane and nitrous oxide are also produced, depending on the actual combustion conditions. Methane may be generated when fuel is heated, but only partially burnt, and depends on combustion temperatures and the level of oxygen present. Nitrous oxide results from the reaction between nitrogen and oxygen in the combustion air.

Direct emission factors give the kilograms of carbon dioxide equivalent (CO_2-e) emitted per unit of activity at the point of emission release. For combustion of fossil fuel for generation, these are typically formulated into a standardised emissions measure per unit of energy (kg CO_2-e per GJ, fuel (tonnes CO_2-e/tonne coal), or a similar measure. It should be noted that these measure are not entirely accurate due to the varying composition of fuels and the efficiency of the combustion process.

Indirect emissions are emissions generated in the wider economy as a consequence of an organisation's activities (particularly from its demand for goods and services), but which are physically produced by the activities of another organisation. In this instance, the primary source of indirect emissions for generators in the WEM would be emissions associated with the production and transport of fuel to the power station. These are referred to as **Scope 3 emissions** (from a generators perspective).[1] A generator is not liable for these emissions, the producers and shippers of the fuels are. However, these organisations are likely to pass theses additional costs through to the generator through clauses in existing contracts wherever possible.

Indirect emission factors give the kilograms of carbon dioxide equivalent (CO_2-e) emitted per unit of fuel delivered to the site. These are typically formulated into a standardised measure of kg CO_2-e per GJ.

[1] Note that the Scope 3 emissions for one entity represent other entities Scope 1 emissions.

Another subset of indirect emissions are **Scope 2 emissions** which specifically relate to the emissions associated with purchased electricity. However, these emissions are not relevant for the electricity sector itself.

2.3 Implications for the WEM

Electricity generation forms a subset of stationary energy and is a significant emitter of greenhouse gases. From 1 July 2012 generators in the WEM will be liable for emissions associated with electricity generation. This will impose significant additional costs for operators of power stations in the WEM and will likely alter the way in which some stations[2] operate in response to the price signal and affect new entrant technology decisions.

In addition, emissions associated with the production and transport of fossil fuels (coal, natural gas and liquid fuel) to most power stations will also come under the CEF, and these additional costs are likely to be passed through to generators.

The resulting increase in direct and indirect costs to generators is likely to result in flow-on affects for wholesale electricity prices in the WEM. The impacts will affect spot prices through the Short-term Energy Market (STEM) as well as prices struck under bilateral contract arrangements.

2.4 Generator direct liabilities

In estimating the liabilities for generators under the carbon pricing mechanism, the principal data source for direct emission factors would be the National Greenhouse Accounts Factors as published by the Department of Climate Change and Energy Efficiency. This document provides the default emission factors for various fuels (Method 1from the National Greenhouse and Energy Reporting (Measurement) Determination 2008).[3]

2.4.1 Solid fuels

For stations consuming solid fuels the following formula applies:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1000}$$

Where:

[2] Note that in some limited cases, generators may not exceed the emissions threshold. For example, gas-fired power stations which consume less than around 0.5 PJ of gas annually would not likely meet the 25,000 tonne CO_2-e annual facility threshold.

[3] It should be noted that there are alternate calculation methods under the NGER Act.

$\mathbf{E_{ij}}$ is the emissions of gas type (j), (carbon dioxide, methane or nitrous oxide), from fuel type(i) (CO2-e tonnes)

$\mathbf{Q_i}$ is the quantity of fuel type (i) (tonnes)

$\mathbf{EC_i}$ is the energy content factor of the fuel (gigajoules per tonne) according to each fuel in Table 1 (if $\mathbf{Q_i}$ is measured in gigajoules, then $\mathbf{EC_i}$ is 1).

$\mathbf{EF_{ijoxec}}$ is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms of CO2-e per gigajoule) according to each fuel in Table 1.

Table 1 **Fuel combustion emission factors – solid fuels and certain coal based products**

Fuel combusted	Energy content factor	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
	GJ/tonne	CO_2	CH_4	N_2O
Black coal (other than that used to produce coke)	27	88.2	0.03	0.2
Brown coal	10.2	92.7	0.01	0.4
Coking coal	30	90	0.02	0.2
Coal briquettes	22.1	93.3	0.06	0.3
Coal coke	27	104.9	0.03	0.2
Coal tar	37.5	81	0.02	0.2
Solid fossil fuels other than those mentioned in the items above	22.1	93.3	0.06	0.3
Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	26.3	79.9	0.02	0.2
Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	10.5	85.4	0.6	1.2
Dry wood	16.2	0	0.08	1.2
Green and air dried wood	10.4	0	0.08	1.2
Sulphite lyes	12.4	0	0.06	0.6
Bagasse	9.6	0	0.2	1.3
Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	12.2	0	0.6	1.2
Charcoal	31.1	0	4	1.2
Primary solid biomass fuels other than those mentioned in the items above	12.2	0	0.6	1.2

Note: Energy content and emission factors for coal products are measured on an as combusted basis. The energy content for black coal and coking coal (metallurgical coal) is on a washed basis.

Data source: Department of Climate Change and Energy Efficiency, National Greenhouse Accounts Factors 2011, page 12

The energy content of black coal used in the SWIS is significantly lower than the 27 GJ/tonne listed in Table 1. ACIL Tasman estimates the energy content to be closer to 20 GJ/tonne. Provided the fuel use is estimated in energy units

(GJ), coal consumption multiplied by 88.43 (88.2+0.03+0.2) will yield emissions in kg CO_2-e.

2.4.2 Gaseous fuels

For stations consuming gaseous fuels the same formula would apply, but with different units:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1000}$$

Where:

E_{ij} is the emissions of gas type (j), (carbon dioxide, methane or nitrous oxide), from gaseous fuel type (i) (CO_2-e tonnes).

Q_i is the quantity of fuel type (i) (cubic metres)

EC_i is the energy content factor of fuel type (i) (gigajoules per cubic metre according to Table 2). If **Q_i** is measured in gigajoules, then **EC_i** is 1.

EF_{ijoxec} is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms CO_2-e per gigajoule of fuel type (i) according to Table 2).

Table 2 **Fuel combustion emission factors – gaseous fuels**

Fuel combusted	Energy content factor (GJ/m^3 unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
		CO_2	CH_4	N_2O
Natural gas distributed in a pipeline	39.3×10^{-3}	51.2	0.1	0.03
Coal seam methane that is captured for combustion	37.7×10^{-3}	51.1	0.2	0.03
Coal mine waste gas that is captured for combustion	37.7×10^{-3}	51.6	5	0.03
Compressed natural gas (reverting to standard conditions)	39.3×10^{-3}	51.2	0.1	0.03
Unprocessed natural gas	39.3×10^{-3}	51.2	0.1	0.03
Ethane	62.9×10^{-3}	56.2	0.02	0.03
Coke oven gas	18.1×10^{-3}	36.8	0.03	0.06
Blast furnace gas	4.0×10^{-3}	232.8	0.02	0.03
Town gas	39.0×10^{-3}	59.9	0.03	0.03
Liquefied natural gas	25.3 GJ/kL	51.2	0.1	0.03
Gaseous fossil fuels other than those mentioned in the items above	39.3×10^{-3}	51.2	0.1	0.03
Landfill biogas that is captured for combustion (methane only)	37.7×10^{-3}	0	4.8	0.03

Fuel combusted	Energy content factor	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
	(GJ/m^3 unless otherwise indicated)	CO_2	CH_4	N_2O
Sludge biogas that is captured for combustion (methane only)	37.7 × 10^{-3}	0	4.8	0.03
A biogas that is captured for combustion, other than those mentioned in the items above	37.7 × 10^{-3}	0	4.8	0.03

Note: All emission factors incorporate relevant oxidation factors (sourced from the DCCEE's National Inventory Report).
Data source: Department of Climate Change and Energy Efficiency, National Greenhouse Accounts Factors 2011, page 14

As most gaseous fuel consumed in the SWIS is natural gas transmitted via the Dampier to Bunbury Natural Gas Pipeline (DBNGP), direct emissions for these stations is estimated by GJ consumed, multiplied by 51.33 (51.2+0.1+0.03) to yield emissions in kg CO_2-e.

2.4.3 Liquid fuels

For stations consuming liquid fuels the following formula would apply:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1000}$$

Where:

E_{ij} is the emissions of gas type (j), (carbon dioxide, methane or nitrous oxide, from fuel type (i) (CO_2-e tonnes).

Q_i is the quantity of fuel type (i) (kilolitres) combusted for stationary energy purposes

EC_i is the energy content factor of fuel type (i) (gigajoules per kilolitre) for stationary energy purposes, according to Table 3. If **Q_i** is measured in gigajoules, then **EC_i** is 1.

EF_{ijoxec} is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms CO_2-e per gigajoule) according to Table 3.

Table 3 **Fuel combustion emission factors – liquid fuels and certain petroleum based products**

Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
		CO_2	CH_4	N_2O
Petroleum based oils (other than petroleum based oil used as fuel, eg lubricants)	38.8	27.9	0	0
Petroleum based greases	38.8	27.9	0	0
Crude oil including crude oil condensates	45.3 GJ/t	68.9	0.06	0.2
Other natural gas liquids	46.5 GJ/t	60.4	0.06	0.2
Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.2	0.2
Gasoline for use as fuel in an aircraft (avgas)	33.1	66.3	0.2	0.2
Kerosene (other than for use as fuel in an aircraft)	37.5	68.2	0.01	0.2
Kerosene for use as fuel in an aircraft (avtur)	36.8	68.9	0.01	0.2
Heating oil	37.3	68.8	0.02	0.2
Diesel oil	38.6	69.2	0.1	0.2
Fuel oil	39.7	72.9	0.03	0.2
Liquefied aromatic hydrocarbons	34.4	69	0.02	0.2
Solvents if mineral turpentine or white spirits	34.4	69	0.02	0.2
Liquefied petroleum gas	25.7	59.6	0.1	0.2
Naphtha	31.4	69	0	0.02
Petroleum coke	34.2 GJ/t	90.8	0.06	0.2
Refinery gas and liquids	42.9 GJ/t	54.2	0.02	0.03
Refinery coke	34.2 GJ/t	90.8	0.06	0.2
Petroleum based products other than mentioned in the items above	34.4	69	0.02	0.2
Biodiesel	34.6	0	0.06	0.2
Ethanol for use as a fuel in an internal combustion engine	23.4	0	0.06	0.2
Biofuels other than those mentioned in the items above	23.4	0	0.06	0.2
Biofuels other than those mentioned in the items above	23.4	0	0.06	0.2

Note: All emission factors incorporate relevant oxidation factors (sourced from the DCCEE's National Inventory Report).
Data source: Department of Climate Change and Energy Efficiency, National Greenhouse Accounts Factors 2011, page 16

Direct emissions for power stations operating on diesel can therefore be estimated as GJ diesel consumed, multiplied by 69.5 (69.2+0.1+0.2) to yield emissions in kg CO_2-e.

2.5 Scope 3 emissions

In the language of carbon accounting, Scope 3 emissions relate to emissions associated with the extraction, production and transport of purchased fuels consumed. For the WEM, these relate to emissions from the extraction, production and transport of coal, natural gas and liquid fuels to power stations.

Scope 3 emissions can be estimated by calculating Scope 1 emissions for the relevant coal, natural gas and liquid fuel operations that service SWIS-based power stations and apportion these emissions accordingly. However, this involves detailed knowledge of the working and characteristics of each of these production processes and fuel contracting arrangements for power stations. For example, an offshore gas field which has significant CO_2 stripping and venting within the production process is likely to have much higher emissions than the industry average. These are likely to be passed on to entities which contract with this fuel source for power generation activities.

Therefore one would need to evaluate each of the fuel sources in detail and apportion emissions to the relevant power stations that contract with this producer.

A simpler method is to use the average Scope 3 emission factors as produced by DCCEE as set out in the following sections. These estimates are based on consultant reports to DCCEE and are based on NGERS data.

2.5.1 Solid fuels

Table 4 details estimates for Scope 3 emissions for solid fuels combusted. The black coal entry – which is likely to be the most relevant entry for the WEM – specifically states that the estimate is for "uses other than electricity and coking". However, there are no other estimates available for black coal which could be used within this document. It should be noted that the Scope 3 estimates are averages for Australia and significant differences can occur between mines.

Table 4 **Scope 3 emission factors –solid fuels**

Solid Fuels combusted	EF for scope 3 (kg CO2-e/GJ)
Black coal—uses other than for electricity and coking	4.6
Brown coal	0.3
Coking coal	20.7
Coal briquettes	10.7
Coal coke	8.3
Solid fossil fuels other than those mentioned above	Not estimated

Data source: Department of Climate Change and Energy Efficiency, National Greenhouse Accounts Factors 2011, page 66

2.5.2 Gaseous fuels

Due to differences in average pipeline transportation differences and differences in gas composition (involving different energy usage and CO_2 stripping during production), Scope 3 emissions factors for natural gas delivered by pipeline is estimated on a regional basis. The Australian

Government's 2011 estimates of Scope 3 emissions factors for gaseous fuels are shown in Table 5, expressed on the basis of units of carbon dioxide equivalent (CO_2-e per GJ) of gas consumed.

Table 5 **Australian natural gas Scope 3 emissions factors – 2011**

Location	Metro users	Non-metro users
	kg CO_2-e/GJ	kg CO_2-e/GJ
New South Wales and the Australian Capital Territory	14.2	15.0
Victoria	4.0	4.0
Queensland	8.6	7.8
South Australia	10.4	10.2
Western Australia	4.0	3.9

Data source: *Data source*: Department of Climate Change and Energy Efficiency, 2011 National Greenhouse Accounts Factors workbook.

2.5.3 Liquid fuels

Table 6 details the estimated Scope 3 emission factors for liquid fuels expressed in kg CO_2-e/GJ. It should be noted that while some liquid-fuelled peaking plant in the WEM would not be directly liable for emissions as they would fall under the 25,000 tonne threshold, they would likely face increased costs as Scope 3 emissions are passed through to them from refineries etc.

Table 6 **Scope 3 emission factors –liquid fuels**

Solid Fuels combusted	EF for scope 3 (kg CO2-e/GJ)
Petroleum based oils (other than petroleum based oil used as fuel, eg lubricants)	5.3
Petroleum based greases	5.3
Crude oil including crude oil condensates	5.3
Other natural gas liquids	5.3
Gasoline (other than for use as fuel in an aircraft)	5.3
Gasoline for use as fuel in an aircraft (avgas)	5.3
Kerosene (other than for use as fuel in an aircraft)	5.3
Kerosene for use as fuel in an aircraft (avtur)	5.3
Heating oil	5.3
Diesel oil	5.3
Fuel oil	5.3
Liquefied aromatic hydrocarbons	5.3
Solvents if mineral turpentine or white spirits	5.3
Liquefied Petroleum Gas	5.0
Naphtha	5.3
Petroleum coke	5.3
Refinery gas and liquids	5.3

Solid Fuels combusted	EF for scope 3 (kg CO2-e/GJ)
Refinery coke	5.3
Petroleum based products other than mentioned in items above	5.3
Biofuels	Not estimated

Data source: Department of Climate Change and Energy Efficiency, National Greenhouse Accounts Factors 2011, page 66

3 What is an Emission Intensity Index?

An Emissions Intensity Index within this context is an index which shows over a defined period of time, what the *average* level of greenhouse gases are emitted to the atmosphere per unit of generation. It would typically be defined in tonnes of CO_2-e per MWh of electricity sent-out to the grid.

It is calculated by first estimating the level of emissions from each power station per period, summing these for the entire system (i.e. the SWIS) which would yield the total emissions, and dividing this by the energy sent-out over the period to yield the average intensity per MWh.

The index would vary over time depending upon the generating plant mix in the WEM.

DCCEE already produce an emission intensity index in the form of estimated emission factors for the SWIS as shown in Table 7. While these emission factors for Scope 2 and Scope 3 are produced for the purpose of informing electricity end users of the emission intensity of electricity they purchase, the Scope 2 estimates are representative of the Scope 1 emissions from the electricity sector.

Table 7 **Scope 2 and 3 emissions factors – consumption of purchased electricity by end users in the SWIS**

Financial year ending June	EF for scope 2		EF for scope 3		Full fuel cycle EF (EF for scope 2 + EF for scope 3)	
	kg CO_2-e/kWh	kg CO_2-e/GJ	kg CO_2-e/kWh	kg CO_2-e/GJ	kg CO_2-e/kWh	kg CO_2-e/GJ
1990	0.91	253	0.16	46	1.08	299
1995	0.92	256	0.14	40	1.07	296
2000	0.92	256	0.12	34	1.04	290
2005	0.85	235	0.10	29	0.95	264
2006	0.86	240	0.10	28	0.96	268
2007	0.86	238	0.08	23	0.94	261
2008	0.85	236	0.10	27	0.94	262
2009	0.81	224	0.10	28	0.91	252
2010	0.80	223	0.13	35	0.93	258

Note: Emission factors are representative of the state's primary electricity grid. To minimise volatility emission factors are calculated as a three-year average.

Data source: Department of Climate Change and Energy Efficiency, National Greenhouse Accounts Factors 2011, page 68

While these emission factors are calculated by a reputable source (DCCEE), they are not suitable for use as a WEM emission intensity index as:

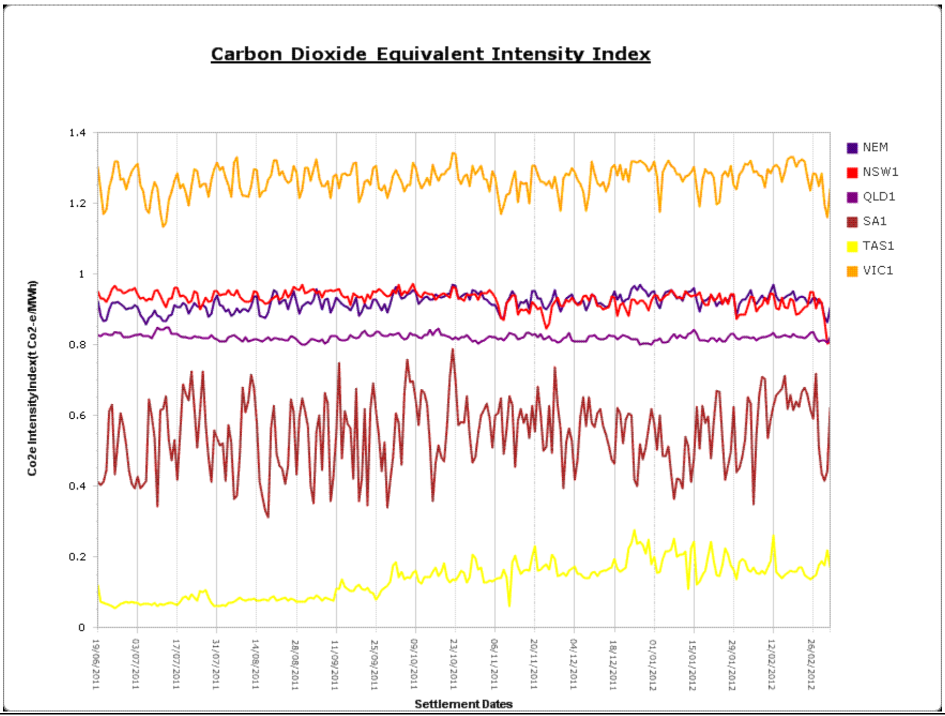
- As they are targeted at end-users these figures include losses from the transmissions and distribution networks
- They are only published on an annual basis and are quite lagged.

The National Electricity Market (NEM) has published for some time an equivalent index called the Carbon Dioxide Equivalent Intensity Index (CDEII). This index is produced by the Australian Energy Market Operator (AEMO) for each NEM region and for the NEM as a whole.

Figure 1 shows around 8 months of index history for the CDEII. Emissions intensity varies considerably among the NEM regions with Victoria the highest (averaging around 1.25 tonnes CO_2-e/MWh) due to brown coal being dominant in the fuel mix. Tasmania has the lowest values – a direct result of hydro generation comprising a large share of generation in this region. The most volatile index is South Australia which has a large component of wind generation. The index for this region therefore fluctuates significantly depending upon wind output.

Overall the NEM Intensity, as measured by the CDEII, averages at around 0.93 tonnes CO_2-e/MWh.

Figure 1 **AEMO's NEM Carbon Dioxide Equivalent Intensity Index**



Data source: http://www.aemo.com.au/electricityops/cdeii.html

3.1 What is it used for?

The index can be used for a number of purposes:

1. To provide a means to estimate total emissions (in tonnes CO_2-e) from generation activities over a period by multiplying by energy generated in the same period
2. To enable participants and external parties to track emission intensity over time to assess impacts of various Government policies including the Clean Energy Future package and Large-scale Renewable Energy Target
3. To enable a simple structured pass-through of relevant cost impacts on price under electricity contracts.

Identified uses 1 and 2 provide market participants and observers with an additional information source and increases transparency of operating of the WEM. While individual generators liabilities under the carbon pricing mechanism will not be visible publically, there is likely to be a need for aggregate measures for the market as a whole. Accurate quantification and reporting of emissions and liabilities – even at an aggregate level – will be of interest to all WEM stakeholders. One could probably justify the development of an EII for the WEM on the basis of this alone.

Utilisation of the index as a price pass-through mechanism within contracts represents a commercial use of the measure and has been the primary driver for the construction of a formalised index in the NEM. The measure is used within the Australian Financial Markets Association (AFMA) standard Over-the-Counter (OTC) contracts with a specific contract addendum[4] which provides the means by which adjustments to agreed prices are made based on CDEII values over a given period.

It is likely a similar requirement will emerge in the WEM.

[4] The Australian Carbon Benchmark Addendum

4 Development of an EII for the WEM

Given that the IMO is looking at developing an EII for the WEM, there are a number of factors to consider both in terms of data sources and the form of the index itself.

4.1 Data requirements

Ultimately the index requires data on emissions at a facility level. This data is then summed up across all SWIS generators and divided by energy in order to calculate the EII for each period.

The IMO already has access to SCADA dispatch data for individual generators for settlements purposes. Given its accuracy and timeliness, this should be used in the calculation of the EII as the denominator.

Emission from WEM power stations would form the numerator. There are a number of alternative data sources the IMO could draw from:

- Statutory NGER data as reported to DCCEE
- IMO estimated intensities based on data provided by generators (i.e. average thermal efficiency and fuel use splits)
- IMO estimated intensities based on estimated inputs

Clearly in the above there is a declining level of accuracy in the intensity estimates, but also a declining level of information provision required by generators. Using publicly available data sources avoids placing administratively intensive reporting burdens on generators.

The following sections provide an overview of these sources and how the IMO might use this data to construct the index.

4.1.1 NGER data

Corporations that are registered under the National Greenhouse and Energy Reporting Act 2007 (the NGER Act) are obliged to report information on their greenhouse gas emissions, energy production and energy consumption to the Greenhouse and Energy Data Officer – currently DCCEE.

The stated objective of the NGER Act is to introduce a single national reporting framework for the reporting and dissemination of information related to greenhouse gas emissions, greenhouse gas projects, energy consumption and energy production of corporations to:

a) underpin the introduction of an emissions trading scheme in the future
b) inform government policy formulation and the Australian public

c) meet Australia's international reporting obligations

d) assist Commonwealth, State and Territory government programs and activities

e) avoid the duplication of similar reporting requirements in the States and Territories.

The publishing thresholds for Scope 1 and Scope 2 greenhouse gas emissions in the NGER Act have reduced over the years as follows:

- 2008-09: equal to or greater than 125,000 tonnes
- 2009-10: equal to or greater than 87,500 tonnes
- 2010-11: equal to or greater than 50,000 tonnes.

Under the NGER legislation, information on energy production and consumption is also collected which provides important data on energy flows occurring throughout the economy. It requires the total amount of each defined commodity to be reported, including each transformation of energy from one fuel or commodity into another.

Table 8 shows the totals for emissions and energy consumption published at corporation level by DCCEE in the first three reporting years. Both emissions and energy consumption have increased primarily due to the lower thresholds under the Act.

Table 8 **Published NGER totals for all corporations**

Reporting year	Total scope 1 greenhouse gas emissions	Total scope 2 greenhouse gas emissions	Total energy consumption
	tonnes CO_2-e	tonnes CO_2-e	GJ
2008-09	345,000,673	93,219,193	6,086,214,251
2009-10	341,937,797	95,119,009	7,605,228,187
2010-11	374,299,427	103,567,837	9,174,970,587

Note: Some corporation may have applied under section 25 of the NGER Act to have all or part of its greenhouse gas emissions and energy consumption totals withheld from publication in which case it will not appear within the totals.
Data source: Department of Climate Change and Energy Efficiency

It is likely that most corporations involved in generation activities in the WEM would be captured by the NGER thresholds and hence already compile this data annually.

The IMO would be looking to obtain emissions data (and potentially fuel use data) relating to each generator in the WEM. This would be a subset of data compiled as part of each organisations NGER reporting task.

Using the emission intensities that participants are already providing as required by the NGER Act would minimise the cost and inconvenience to participants while ensuring reliable and standardised input data. The IMO would need to state and ensure that any such data provided would remain confidential.

If NGER data is used, it is likely to take the form of Scope 1 emissions over a financial year. IMO could calculate the emission intensity of the relevant power station by dividing these emissions by the sent-out generation in the same period as follows:

$$EI_i = \frac{E_i}{DSO_i}$$

Where:

EI_i = Emission Intensity for individual generator (i) (t CO_2-e /MWh)

E_i = Scope 1 emissions as reported under NGER for the station (t CO_2-e)

DSO_i = Sent-out dispatch from SCADA data for the station (MWh).

4.1.2 Participant provided thermal efficiencies

If there were reservations with providing extracts from NGER reports, a reasonable compromise may be to request provision of thermal efficiency and fuel split data. This would involve the IMO seeking average historical thermal efficiency data and the split of fuels used in each power station.

The appropriate efficiency to request for each generator would be the sent-out thermal efficiency specified on a High-Heat Value (HHV) basis[5]. This could be specified as a percentage (%) or alternatively on a GJ/MWh basis.

Armed with this data, the IMO could calculate implied fuel use (for each fuel) for each generator based on dispatch data.

To calculate emissions, the IMO could utilise the DCCEE emission factors as set out in sections 2.4 and 2.5 for Scope 1 and Scope 3 emissions (if required) respectively.

Where a power station utilised more than one fuel type, splits would be required for the proportion of generation on each fuel and any changes to thermal efficiency that result from operation on the alternate fuel.

To convert thermal efficiencies (expressed in percentage sent-out terms, the following formula would be used:

[5] A HHV measure takes into account the latent heat of vaporisation of the fuel

$$EI_i = \left(\frac{3.6}{TE_i}\right) \times ef_i$$

Where:

EI_i = Emission Intensity for individual generator (i) (t CO_2-e /MWh)

TE_i = Thermal Efficiency (MWh(sent-out)/MWh(Fuel))

ef_i = Emission Factor for individual generator (t CO2-e /GJ)

3.6 = Conversion factor (1 MWh = 3.6 GJ).

To convert thermal efficiencies (expressed in GJ per MWh sent-out terms, the following formula would be used:

$$EI_i = TE_i \times ef_i$$

Where:

EI_i = Emission Intensity for individual generator (i) (t CO_2-e /MWh)

TE_i = Thermal Efficiency (GJ/MWh)

ef_i = Emission Factor for individual generator (t CO2-e /GJ).

4.1.3 IMO estimates

If participants were reluctant to provide any data, of in cases of incomplete or missing data, it may be necessary for the IMO to estimate emissions based on estimated thermal efficiencies.

Despite intentions to the contrary, this is how the NEM CDEII emission factor values for each power station are calculated. Thermal efficiencies are largely are sourced from the National Transmission Network Development Plan (NTNDP) consultations.[6] These are estimated thermal efficiencies developed by consultants such as ACIL Tasman.

The IMO may already have access to thermal efficiency data or estimates as part of other market operational functions or oversight. If estimates are not currently available, the IMO could commission consultants to provide estimated thermal efficiencies for each generator in the SWIS.

[6] For example, see the data sources listed within http://www.nemweb.com.au/reports/current/cdeii/CO2EII_Available_Generators.csv

4.2 Index construction

To construct the EII, a two-step process is involved:

- Calculating emission intensities for individual power stations (as discussed in the previous sections). This can be done initially and values only change periodically (say once a year) or when new stations enter service
- Calculating WEM emission intensity index values by calculating total emissions for the WEM and dividing by sent-out energy in the period.

Given that power station emission intensities have been calculated and set for the period in question, the IMO would need to calculate the EII for the WEM using the following formula:

$$WEM\ EII = \frac{\sum EI_i \times DSO_i}{DSO}$$

Where:

WEM EII = Emission intensity index for the WEM (t CO_2-e/MWh sent-out)

EI_i = Emission intensity of generator (i) (t CO_2-e/MWh sent-out)

DSO_i = Sent-out dispatch of generator (i) (MWh sent-out)

DSO = Sent-out dispatch for the system (MWh sent-out)

The resultant EII for the WEM will be reported in tonnes of CO_2-e per megawatt hour sent out (t CO2-e/MWh sent-out).

4.2.1 Resolution

Calculations for the index can be done at varying intervals:

- For each 30 minute trading period
- Daily
- Monthly
- Quarterly
- Annually.

The index can also be calculated for peak and off-peak periods within the time intervals above if participants would find this useful. Publishing values for each 30 minute trading interval allows market participants to construct any number of hybrid indices.

ACIL Tasman would recommend that the IMO publish the index at 30 minute resolution, but also calculate and publish peak, off-peak and flat indices daily and monthly.

4.2.2 Inclusion or exclusion of Scope 3 emissions

There is a question as to whether the individual station emission intensities should be inclusive of Scope 3 emissions or not.

The primary arguments for their inclusion are that increased fuel costs as a result of the CEF are likely to be passed through to power stations. This will affect generating costs and therefore prices within the WEM. Given that the index may be used as a means of price pass through, the inclusion of Scope 3 emissions has merit.

However, the downside to their inclusion is that they represent emissions that are occurring outside the boundaries of the electricity generation sector. Use of the index to estimate emissions from generation activities in the WEM therefore requires Scope 3 emission factors be excluded.

As a means of addressing both potential uses of the index, it would be possible for the IMO to publish two indices – one including Scope 3 emissions and one excluding Scope 3 emissions. This would require two emission intensity values for each power station.

4.3 Issues with use of EII for price pass-through

One of the primary drivers for the development of the CDEII in the NEM was for use as a pass-through mechanism on OTC hedge contracts. While this provides a simple means of adjusting prices, it may not reflect the actual price changes brought about by the CEF.

The primary issue is related to the index being an average intensity value, whereas the wholesale market pricing is determined by the marginal generator. At times there is likely to be significant difference between the average emissions intensity and the emissions intensity of the marginal generator.

However, these issues are outside the scope of IMO's concerns as to what participants use the index for, and may not be as relevant for the WEM, being a net pool system.

4.4 Index maintenance

While calculation of the index will be ongoing, power station emission intensities will require periodic updating and revision.

It is recommended that a review occur at least once a year to ensure emission intensity values ascribed are current and as accurate as possible. In the NEM the emission intensities are examined each year through the NTNDP consultation process, which allows market participants to provide feedback and comment on a whole range of assumptions regarding existing power stations – including emission intensities.

We are not aware of any similar modelling exercises undertaken by the IMO. Therefore, it may be necessary to create a dedicated consultation process for power station emission intensities used in the EII.

4.5 Publication

The IMO should look to publish the EII, aggregate emissions and emission intensity values for power stations on its website. Emissions and EII values could be published as soon as the relevant SCADA dispatch data is available to the IMO.

5 Market consultation

ACIL Tasman understands that it is the IMOs intention to seek feedback from participants and stakeholders views on the construction of the EII.

From our perspective we see a number of key questions the IMO should be asking of interested parties. These are listed below, along with ACIL Tasman's recommended response/ approach to each.

1. What should the primary data source for emission intensity factors for individual power stations be:
   - Statutory NGER data as reported to DCCEE each year
   - IMO estimated intensities based on data provided by generators (i.e. average thermal efficiency and fuel use splits)
   - IMO estimated intensities based on estimated inputs

> ACIL Tasman recommends that ideally, the IMO use emission factors for individual facilities based on, or sourced from, statutory NGER reporting as this will be the most accurate source.

2. Should the index include Scope 3 emissions or be limited to direct emissions (Scope 1) from the power stations only?

> In the first instance at least, ACIL Tasman recommends that the EII be based on Scope 1 (direct) emissions only. Participants are unlikely to have accurate data at this point on what emissions and additional charges will flow through from fuel production and transport. Limiting the emission factors to Scope 1 also allows calculation of emissions directly resulting from generation activities in the WEM.

3. Is there merit in the IMO publishing both measures?

> There may be merit in the future in publishing a secondary (or incremental) measure which includes Scope 3 emissions once more accurate data becomes available.

4. Should power stations that potentially come under the 25,000 tonne CO_2-e annual threshold be included or excluded in the index?

> ACIL Tasman recommends that facilities which come under the individual facility liability threshold be included within the index. This will ensure that emissions from all operating power stations are included within the index (allows a more accurate aggregate emissions estimate) and avoids the need for

subsequent annual inclusion/removal of individual power stations which have large variations in utilisation year-to-year.

Inclusion of non-liable facilities is unlikely to materially affect the index values due to their low level of emissions and small share of generation.

It should be noted that liability under the CEF legislation occurs at the facility level, whereas reporting requirements under NGER is at the corporation level.[7] For this reason, emission data is likely to be already compiled for these stations under NGER reporting obligations despite them potentially not being liable under CEF.

5. How frequently should the index be published? Quarterly, Monthly, Weekly, Daily, Trading period resolution?

ACIL Tasman recommends that the EII be calculated and published at a Trading period resolution. This will allow parties to construct various aggregate measures. In addition, ACIL Tasman also recommends that the IMO publish monthly averages to assist parties with contractual pass-through clauses.

6. Are peak/off-peak breakdowns likely to be of use?

Given that the index is likely to be published at a Trading period resolution, parties will be able to construct peak/off-peak splits as they see fit. To limit the reporting burden on the IMO, ACIL Tasman recommends that the EII only be reported in accordance with the recommendations to Question 5.

7. Should the index be an informal measure or be formalised within the market rules and IMO procedures?

Ultimately the EII should become formalised within the market rules and procedures. However, due to time constraints, it would be prudent to have an informal index up and running prior to the commencement of the CEF on 1 July 2012 if possible.

8. How regularly should input data (or estimates) be updated? What would the process be?

ACIL Tasman recommends that the emission factors for individual facilities be updated at least annually. The most suitable time would be once new NGER data is available.

[7] For more general information on liability under the CEF see: http://www.cleanenergyfuture.gov.au/wp-content/uploads/2011/11/fact-sheet-19-carbon-pricing-mechanism-PDF.pdf