Principles for Assessing Emissions Reductions from DSM Measures

Research Report No 2
Task XVIII of the International Energy Agency Demand Side Management Programme

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THE IEA DEMAND SIDE MANAGEMENT PROGRAMME

The International Energy Agency (IEA) was established in 1974 as an autonomous agency within the framework of the Economic Cooperation and Development (OECD) to carry out a comprehensive program of energy cooperation among its 25 Member countries and the Commission of the European Communities.

An important part of the Agency's program involves collaboration in the research, development and demonstration of new energy technologies to reduce excessive reliance on imported oil, increase long-term energy security and reduce greenhouse gas emissions. The IEA's R&D activities are headed by the Committee on Energy Research and Technology (CERT) and supported by a small Secretariat staff, headquartered in Paris. In addition, three Working Parties are charged with monitoring the various collaborative energy agreements, identifying new areas for cooperation and advising the CERT on policy matters.

Collaborative programs in the various energy technology areas are conducted under Implementing Agreements, which are signed by contracting parties (government agencies or entities designated by them). There are currently over 40 Implementing Agreements, including the IEA Demand-Side Management Programme. Since 1993, the following 20 member countries have been working to clarify and promote opportunities for DSM.

Australia	France	New Zealand
Austria	Greece	Norway
Belgium	Italy	Spain
Canada	India	Sweden
Denmark	Japan (Sponsor)	Switzerland
European Commission	Republic of Korea	United Kingdom
Finland	Netherlands	United States

A total of 22 Tasks (multi-national collaborative research projects) have been initiated by the IEA DSM Programme, 15 of which have been completed. Each Task is managed by an Operating Agent (Project Director) from one of the participating countries. The Operating Agent is responsible for overall project management including project deliverables, milestones, schedule, budget and communications. Overall control of the program rests with an Executive Committee comprised of one representative from each contracting party to the Implementing Agreement. In addition, a number of special ad hoc activities–conferences and workshops–have been organized.

The actual research work for a Task is carried out by a combination of the Operating Agent and a group of Country Experts, depending on the nature of the work to be carried out. Each country which is participating in a Task nominates one or more persons as its Country Expert. Each Expert is responsible for carrying out any research work within his/her country which is required for the Task All the Experts meet regularly to review and assess the progress of the work completed by the Operating Agent and by the group of Experts. Experts meetings are usually held between two and four times a year.

The IEA DSM Programme has undertaken the following Tasks to date:

Task I*	International Database on Demand-Side Management
Task II*	Communications Technologies for Demand-Side Management
Task III*	Cooperative Procurement of Innovative Technologies for Demand-Side Management
Task IV*	Development of Improved Methods for Integrating Demand-Side Management
Task V*	Investigation of Techniques for Implementation of Demand-Side Management Technology in the Marketplace
Task VI*	Mechanisms for Promoting DSM and Energy Efficiency in Changing Electricity Businesses
Task VII*	International Collaboration on Market Transformation
Task VIII*	Demand Side Bidding in a Competitive Electricity Market
Task IX*	The Role of Municipalities in a Liberalized System
Task X*	Performance Contracting
Task XI*	Time of Use Pricing and Energy Use for Demand Management Delivery
Task XII*	Cooperation on Energy Standards (not proceeded with)
Task XIII*	Demand Response Resources
Task XIV*	Market Mechanisms for White Certificates Trading
Task XV*	Network-Driven Demand Side Management
Task XVI	Competitive Energy Services
Task XVII	Integration of Demand Side Management, Energy Efficiency, Distributed Generation and Renewable Energy Sources
Task XVIII	Demand Side Management and Climate Change
Task XIX	Micro Demand Response and Energy Saving
Task XX	Branding of Energy Efficiency
Task XXI	Standardisation of Energy Savings Calculations
Task XXII	Energy Efficiency Portfolio Standards

* Completed Task

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FOREWORD

This report is a result of work which was completed within Task XVIII of the International Energy Agency Demand-Side Management Programme. The title of Task XVIII is "DSM and Climate Change." Task XVIII is a multinational collaborative research project which is investigating circumstances in which DSM can contribute to mitigating greenhouse gas emissions and emissions mitigation measures can achieve benefits for electricity systems.

Task XVIII is organised into six subtasks as follows:

- **Subtask 1:** Interactions between DSM and Climate Change;
- **Subtask 2:** Principles for Assessing Emissions Reductions from DSM Measures;
- **Subtask 3:** Mitigating Emissions and Delivering Electricity System Benefits;
- **Subtask 4:** Fungibility of DSM and Emissions Trading;
- **Subtask 5:** TOU Pricing and Emissions Mitigation;
- **Subtask 6:** Communicating Information about DSM and Climate Change.

This report summarises the results from Subtask 2.

The Operating Agent (Project Director) for Task XVIII is Energy Futures Australia Pty Ltd, based in Sydney, Australia.

The work of Task XVIII is supported (through cost and task sharing) by the four participating countries: Australia, France, India and Spain. Participants provided one or more Country Experts who were responsible for contributing to the work of the Task and for reviewing work as it was completed.

Information for this report was collected, and the document was reviewed by, Country Experts and representatives from the organisations listed in the Table on page vii.

The Principal Investigators for this report are Dr Ajit Pujari of Elite Carbon Pty Ltd and Dr David Crossley of Energy Futures Australia Pty Ltd.

Dr Pujari wrote an initial draft of this report based on a presentation he prepared and gave to a Task XVIII Experts meeting. He was also responsible for the literature review on carbon accounting methodologies and he carried out the example calculations of emissions reductions from four DSM projects.

The final version of this report was written by Dr Crossley who also provides Operating Agent services for Task XVIII through his consultancy company Energy Futures Australia.

Any errors and omissions in this report are the responsibility of Dr Pujari and Dr Crossley.

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EXECUTIVE SUMMARY

The purpose of this report is to identify the principles involved in assessing the GHG emission reductions available from implementing DSM measures. DSM measures are usually implemented as part of a specific DSM project. Calculating emission reductions (or possibly increases) from DSM measures involves measuring the levels of emissions before and after a DSM project is carried out. Any changes in emissions from the baseline established before the project was carried out can then be attributed to the DSM measures implemented during the project.

Accurately calculating the GHG emissions reductions from individual DSM projects requires a methodology that focusses on the impact of energy trading on changing the generation mix in the wholesale electricity market. As the generation mix changes, so will the marginal power plant, ie the plant that would be backed off in response to a load reduction caused by a DSM measure. Since different power plants have different emissions factors, the quantity of emissions reductions achieved by a DSM measure will change over time.

The example calculations of emission reductions from DSM projects in section 4 of this report demonstrate the impact that changes in the generation mix during the day in two Australian States have on the quantity of emissions reductions achieved by DSM projects. The differences would be even more pronounced when comparing two countries with different generation mixes. For example, in Australia the base load generation in most States is dominated by coal-fired power plants with high greenhouse intensities and the load following plants (gas and hydro) have lower greenhouse intensities. In contrast, in France the base load generation is nuclear with essentially zero emissions, while the load following plants (gas and oil) have higher greenhouse intensities. In the case of France, the marginal emissions factor during peak times will be higher than the average emissions factor, and so the emissions reduction calculated using the marginal factor would be higher than reduction calculated using the average factor. In most Australian States, the opposite is the case.

Electricity markets typically operate in 48 daily half hour trading periods. Therefore an effective and accurate methodology for calculating emission reductions from DSM projects must be able to identify changes in marginal power stations over a 30 minute time period. A range of suitable methodologies is available that can track these changes over time with varying levels of accuracy. As the accuracy of the methods increases, larger quantities of electricity market data are required.

Calculations of the GHG emissions reductions from individual DSM projects will always be estimates, the accuracy of which depends on the assumptions made about events in the electricity market and about how various DSM measures operate. Methods that use marginal emissions factors will always be more accurate than methods using average emissions factors, but the methods using marginal factors require much larger quantities of detailed data. The level of resources expended on carrying out such calculations should be appropriate to the level of accuracy required. The required accuracy level is ultimately determined by the purpose for which the emissions reduction are calculated, ie how the estimates of emissions reductions are intended to be used.

1. INTRODUCTION

1.1 Demand-side Management

In the electricity industry, the term 'demand-side management' (DSM) is used to refer to actions which change the electrical demand on the system.

Task XVIII takes a broad view of demand-side management and includes the following measures within the definition of DSM:

- distributed generation, including standby generation and cogeneration;
- energy efficiency;
- fuel substitution;
- load management, including interruptible loads, direct load control, and demand response;
- power factor correction;
- pricing initiatives, including time of use and demand-based tariffs.

1.2 Purpose of Task XVIII

The purpose of Task XVIII is to investigate the potential contribution to mitigating greenhouse gas (GHG) emissions that can be made by DSM measures and the extent to which emission mitigation measures can achieve benefits for electricity systems.

Currently, DSM and emission mitigation measures are implemented quite independently:

- DSM measures are implemented primarily to assist and improve the operation of electricity systems. Any impacts (positive or negative) of DSM measures on climate change are only a minor consideration, if they are considered at all;
- efforts to mitigate GHG emissions from electricity production have focussed on improving the efficiency of both electricity generation and end-use. However, emission mitigation measures focussed on increasing end-use efficiency have usually not considered any benefits to the electricity system (eg peak load reduction) that might be gained through implementing the measures.

The overall aim of Task XVIII is to reconcile these two different approaches so as to identify circumstances in which DSM can contribute to mitigating GHG emissions and emission mitigation measures can achieve benefits for electricity systems. Task XVIII then determines what is required to maximise the emissions reductions and electricity system benefits from these two types of measures.

1.3 Purpose of this Report

The purpose of this report is to identify the principles involved in assessing the GHG emission reductions available from implementing DSM measures. The report examines existing carbon accounting methodologies to identify methods which could be used to assess the GHG emissions reductions available from DSM measures. These methods are then tested by calculating emission reductions from a range of actual DSM projects. Finally, the report draws some conclusions about the principles applicable in assessing the GHG emission reductions available from DSM measures.

2. GHG ACCOUNTING FOR PROJECTS

2.1 Project Accounting

DSM measures are usually implemented as part of a specific project, such as operating a standby generator, installing energy efficient lighting and/or air conditioning in a facility (such as a factory or a commercial building), or cycling household air conditioners during the peak time on an electricity network. Calculating emission reductions (or possibly increases) from DSM measures involves measuring the levels of emissions before and after a DSM project is carried out. Any changes in emissions from the baseline established before the project was carried out can then be attributed to the DSM measures implemented during the project.

The GHG Protocol for Project Accounting[1] ("Project Protocol") provides specific principles, concepts, and methods for quantifying and reporting GHG reductions resulting from projects. The Project Protocol's objectives are:

- to provide a credible and transparent approach for quantifying and reporting GHG reductions from GHG projects;
- to enhance the credibility of GHG project accounting through the application of common accounting concepts, procedures, and principles; and
- to provide a platform for harmonization among different project-based GHG initiatives and programs.

To clarify where specific actions are essential to meeting these objectives, the Project Protocol presents requirements for quantifying and reporting GHG reductions and provides guidance and principles for meeting those requirements.

2.2 Defining a Project

The Project Protocol defines a project as a specific activity or set of activities intended to reduce GHG emissions, increase the storage of carbon, or enhance GHG removals from the atmosphere[2]. A project activity is a specific action or intervention targeted at changing GHG emissions, removals, or storage. An activity may include modifications to existing production, process, consumption, service, delivery or management systems, as well as the introduction of new systems.

In the case of a DSM project, the project's main purpose is usually not to reduce GHG emissions, but rather to provide a benefit to the electricity system. Nevertheless, the methods for quantifying and reporting GHG reductions contained in the Project Protocol can be used for DSM projects. A supplement to the Project Protocol *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*[3] ("Grid-Connected Guidelines") facilitates the use of these methods for projects that involve electricity supplied from the grid, such as DSM projects.

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1 World Business Council for Sustainable Development and World Resources Institute (2005). *The GHG Protocol for Project Accounting*. Geneva, WBCSD.

2 World Business Council for Sustainable Development and World Resources Institute (2005). *Op. cit.*, p 11.

3 World Business Council for Sustainable Development and World Resources Institute (2007). *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*. Geneva, WBCSD.

For DSM projects, the relevant project activity is the implementation of one or more DSM measures. These measures reduce the need for grid-based electricity by either[4]:

- improving the efficiency with which grid electricity is used for a particular application; or
- generating electricity on-site so that supply from the grid is unnecessary.

GHG emissions reductions occur to the extent that combustion emissions on the grid are avoided and, where on-site generation is involved, project activity GHG emissions are lower than emissions from grid sources.

2.3 GHG Effects

The Project Protocol defines GHG effects as changes in GHG emissions, removals, or storage caused by a project activity[5]. Changes in emissions are measured in relation to the emissions under the project's "baseline scenario" (referred to as "baseline emissions")[6].

There are two types of GHG effects: primary effects and secondary effects.

A **primary effect** is the intended change in GHG emissions, removals, or storage caused by a project activity, relative to baseline emissions. Each project activity will generally have only one primary effect. In the case of DSM projects, the primary effect is the reduction of combustion emissions from grid-connected power plants.

A **secondary effect** is an unintended change caused by a project activity in GHG emissions, removals, or storage. Secondary effects are typically small relative to a project activity's primary effect. Secondary effects are classified into two categories:

- **one-time effects**—changes in GHG emissions associated with the construction, installation, and establishment or the decommissioning and termination of the project activity;
- **upstream and downstream effects**—recurring changes in GHG emissions associated with inputs to the project activity (upstream) or products from the project activity (downstream), relative to baseline emissions.

This report will be concerned only with primary GHG effects of DSM projects because the secondary effects of a DSM measure are usually small relative to the measure's primary effect.

2.4 Determining Project Baselines

Quantifying a grid-connected project's GHG emission reductions is done by subtracting actual GHG emissions associated with the project's implementation from an estimate of GHG emissions under its baseline scenario. The baseline scenario describes the situation before the project was implemented or the situation that would occur if the project had not been implemented (see Figure 1, page 4).

4 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, pp 5-6.

5 *Ibid.*

6 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 11.

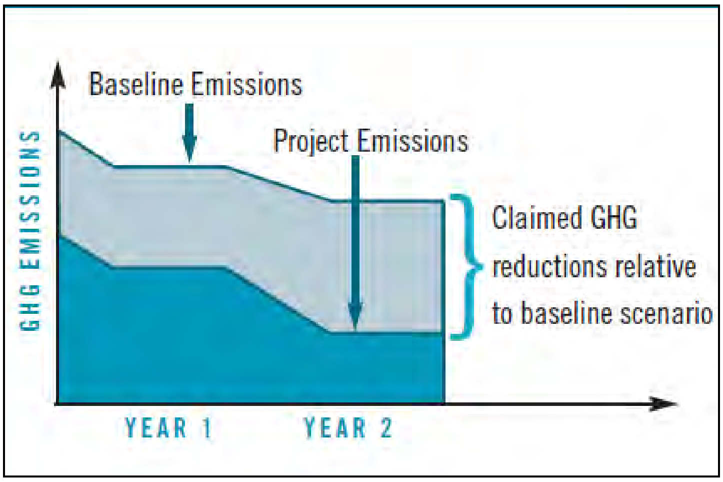

Figure 1. Quantifying GHG Reductions from Projects[7]

The emission reductions achieved by a grid-connected project are the result of a reduction in the quantity of electricity consumed, ie the production of electricity savings. Electricity savings cannot be directly measured. Instead they are determined by comparing actual electricity consumption with estimates of baseline consumption derived from an appropriate analysis.

The term *adjusted consumption baseline* is commonly used to describe the amount of grid electricity that would have been consumed without the project activity[8]. The avoided electricity usage, or electricity saving, is then determined by subtracting actual electricity consumption during the project activity's operation from the adjusted consumption baseline.

The term "adjusted consumption baseline" is used because estimates of baseline electricity usage must often be adjusted to account for changes in usage unrelated to the project activity. For example, if a manufacturing plant's production level drops, the associated reduction in electricity usage should not be confused with any reduction caused by an energy efficiency-enhancing project activity. Thus, baseline estimates of electricity usage must be re-stated using actual measurements of usage with the reduced production levels. Without such adjustment, a portion of the difference between baseline estimates and project activity electricity usage may be attributed to events unrelated to the project activity.

Standard methods for determining an adjusted consumption baseline often rely on historical measurements of electricity usage prior to the implementation of a project activity. Using historical information to characterise the baseline implies that the project activity's baseline scenario involves the "continuation of current activities"[9]. This may be reasonable for many grid-connected project activities. However, in accounting for

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7 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 11.

8 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 20.

9 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 20.

reductions in GHG emissions resulting from a project activity, a full analysis should be conducted to demonstrate that the baseline scenario would not involve an alternative new technology or practice, and would not involve the project activity itself.

For example, some project activities may replace obsolete equipment with a currently available, standard equivalent. Since technology tends to improve over time, the standard replacement is likely to reduce electricity usage relative to historical levels. Also, the replacement would be likely to occur regardless of any considerations about GHG reductions and climate change. Because of this, the projected baseline scenario would involve the same replacement, so no GHG reductions would occur relative to baseline emissions. For the project activity to produce quantifiable GHG reductions, it would have to involve a more energy efficient model than current "standard" equipment.

Well-developed standards exist for determining the adjusted consumption baseline for individual end-user activities. The Efficiency Valuation Organization's *International Performance Measurement and Verification Protocol* (IPMVP), for example, contains extensive guidance for this purpose, including detailed descriptions of computation methodologies and monitoring methods[10].

2.5 Build Margin and Operating Margin

The emissions reductions achieved by a grid-connected project activity (such as implementing DSM measures) are estimated by determining the GHG emissions of the electricity generation that the project activity displaces or avoids. A project activity can displace or avoid the operation of existing grid-connected power plants and/or the construction and operation of new power plants. The Grid-Connected Guidelines assume that these effects can be distinguished and separately assessed[11]. Generation displaced from existing power plants is referred to as the "operating margin". Generation from potential new capacity, whose construction is avoided due to the project activity, is referred to as the "build margin".

Build margins are relevant where grid-connected project activities are able to reduce the need for new electricity generation capacity. In this case, an additional power plant either does not need to be built or can be reduced in size. Build margin emissions are estimated from the GHG emission rates of recent capacity additions, such as new power plants, or in some cases, planned and under-construction capacity[12]. However, most DSM projects are too small to significantly reduce the need for new power plant capacity[13]. Therefore, build margins will not be considered further in this report.

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[10] Efficiency Valuation Organization (2009). *International Performance Measurement and Verification Protocol. Volume I: Concepts and Options for Determining Energy and Water Savings*. San Francisco, EVO.

[11] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 13.

[12] *Ibid.*

[13] However, large scale energy efficiency programs, such as utility-sponsored DSM programs in California or the Bachat Lamp Yojana compact fluorescent lamp replacement program in India, do reduce the need for new power plant capacity. Hence, build margin emissions reductions must be included when estimating emissions reductions from such programs.

Operating margin (OM) emissions are estimated using methods that attempt to approximate the emissions from the specific existing power plants whose operation is displaced by the grid-connected project activity. This estimation requires identifying which power plants are supplying electricity at the margin (ie the last to be switched on-line or first to be switched off-line) during times when the project activity is operating. The metric that estimates the emissions intensity (tCO_2–e/MWh) of electricity supplied from a marginal power plant is called the *marginal emissions factor* (MEF) and is distinguished from the *average emissions factor* (AEF) that estimates the average emissions intensity of electricity supplied from all power plants on the grid.

3. OPERATING MARGIN EMISSIONS REDUCTIONS

3.1 Variation of OM Emissions Over Time

In practice, identifying the marginal power plant during times when a project activity is operating is difficult. The marginal plant may vary over the course of a day, depending on the generation mix available on the grid.

Figure 2 presents a simplified example involving a grid with three different power plants: a 50 MW coal plant (dispatched first); a 30 MW natural gas plant (dispatched second); and a 10 MW oil-fired plant (dispatched only to meet peak loads). The last power plant to be dispatched in each hour is at the Operating Margin, as indicated below the x-axis of the graph. Generation avoided by a project activity might therefore have been provided by a different fuel in each hour, with consequent differences over time in the GHG emissions reductions achieved by the project.

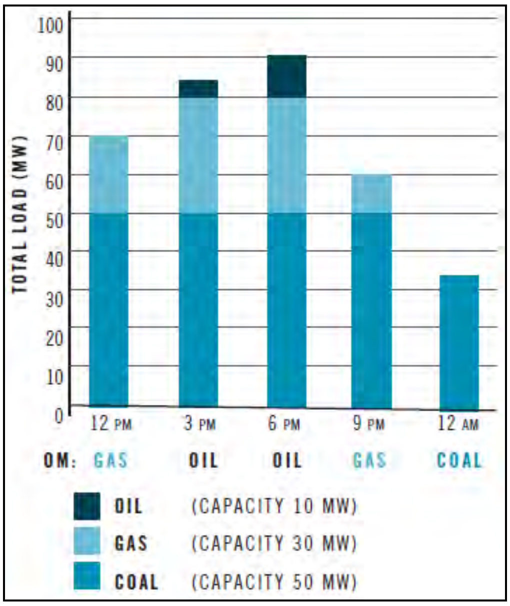

Figure 2. Simplified Example of Changes in the Marginal Power Plant over a Day[14]

[14] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 14.

Operating Margin emissions can vary considerably over time depending on load levels, the types of power plants on the grid, and the order in which they are dispatched to meet load. A study[15] carried out for Task XVIII tracked changes in the generation mix in the New South Wales (NSW) region of the Australian National Electricity Market (NEM) and consequent variations over time in the GHG emissions intensity of electricity supplied through the NEM.

The study calculated the monthly average total emissions (tCO_2-e) for electricity supplied in NSW for each half hour period during a year. The total emissions data were divided by the total quantity of energy supplied to give a monthly average emissions factor (tCO_2-e/MWh) for electricity supplied in NSW for each half hour period. Monthly average half-hourly emission indices were then calculated by dividing the monthly emissions factor for each half hour period by the average of the 12 monthly emissions factors for the same half hour period in each calendar year.

Figure 3 (below) and Figure 4 (page 8) show annual and five-year average GHG emission indices for electricity supplied in NSW for each of the 48 half hour periods during the day over the five calendar years 2003 to 2007. Across the day, there is a variation of 12.1% between the lowest and highest five year average emission indices.

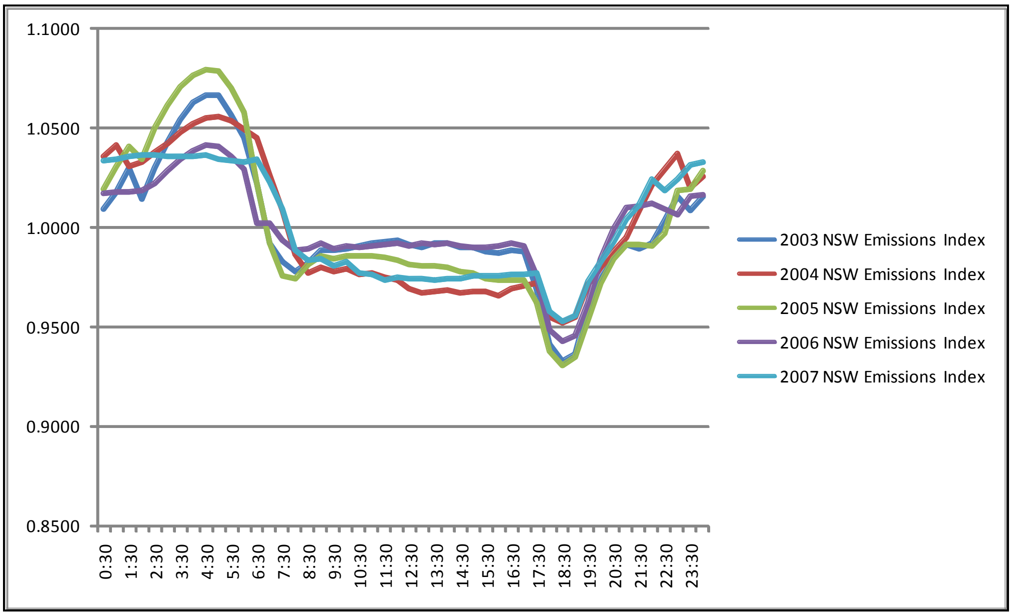

Figure 3. Annual Average GHG Emission Indices for Electricity Supplied in NSW, Calendar Years 2003 to 2007[16]

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[15] Crossley, D. J. (2008a). *Preliminary Study of the Calculation of Time-Varying Greenhouse Gas Emissions Indices*. International Energy Agency Demand Side Management Programme, Task XVIII Working Paper No 1. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

[16] Crossley (2008a), *Op. cit.,* p 4.

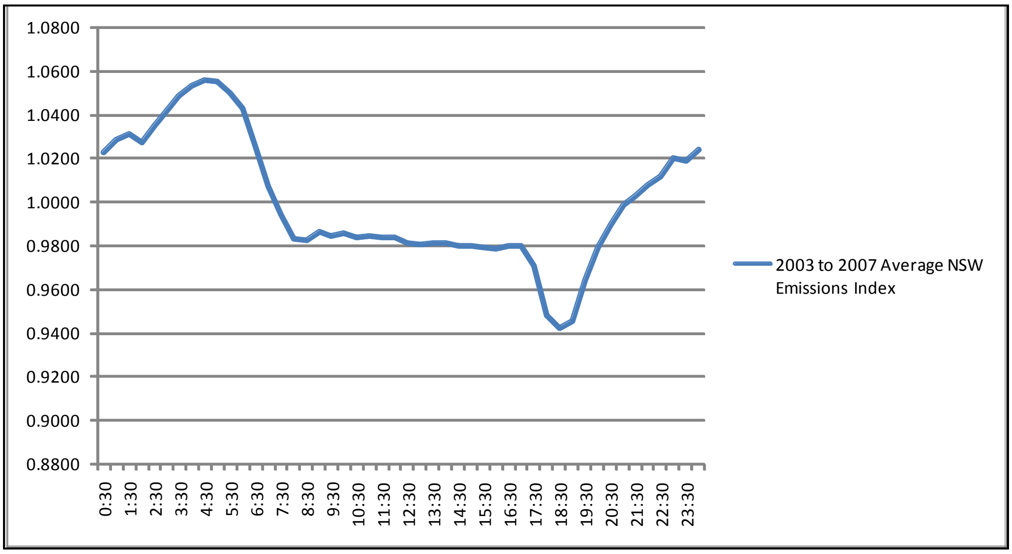

Figure 4. Five Year Average GHG Emission Index for Electricity Supplied in NSW, Calendar Years 2003 to 2007[17]

Figure 5 demonstrates how the emission indices for electricity supplied in NSW vary by days of the week (weekdays versus weekends and public holidays) and by season (summer versus winter). For the purposes of calculating the indices, the southern hemisphere 'summer' was defined as October to March and 'winter' was defined as April to September. Figure 5 demonstrates that there is also significant weekly and seasonal variation in the emissions intensity of electricity supplied through the National Electricity Market.

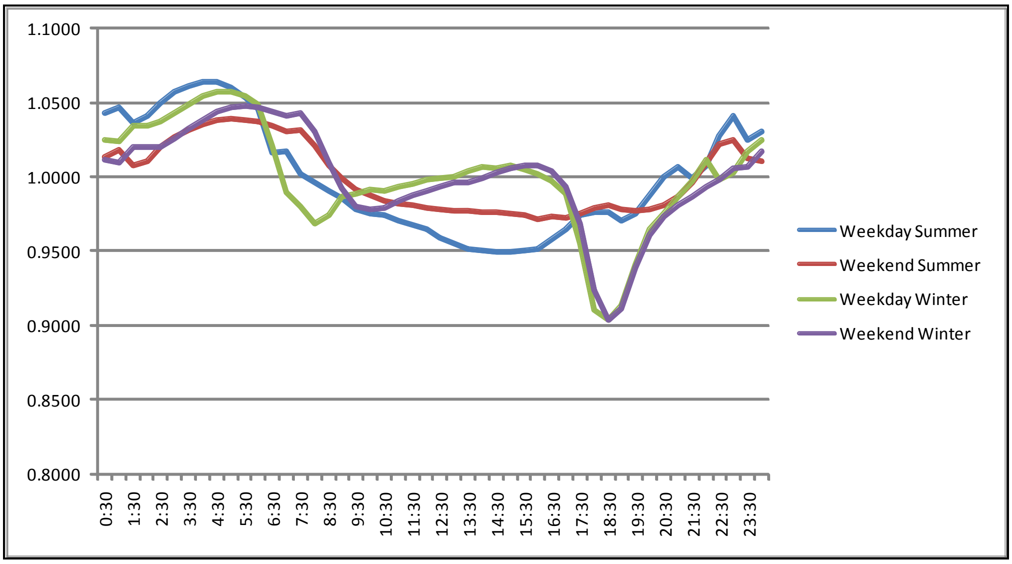

Figure 5. Five Year Average Weekly and Seasonal GHG Emission Indices for Electricity Supplied in NSW, Calendar Years 2003 to 2007[18]

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[17] Crossley (2008a), *Op. cit.,* p 5.
[18] *Ibid.*

A similar result was recently obtained in Great Britain by Hawkes[19]. Figure 6 shows the marginal emissions factor (MEF) and the average emissions factor (AEF) of electricity supplied in Great Britain between 2002 and 2009. Both factors vary over the time of day, with the MEF showing much greater volatility than the MEF. The significant drop in the value of the MEF in the middle of the afternoon is caused by natural flow hydro generation coming on-line in the 3.00 to 3.30 pm market settlement period.

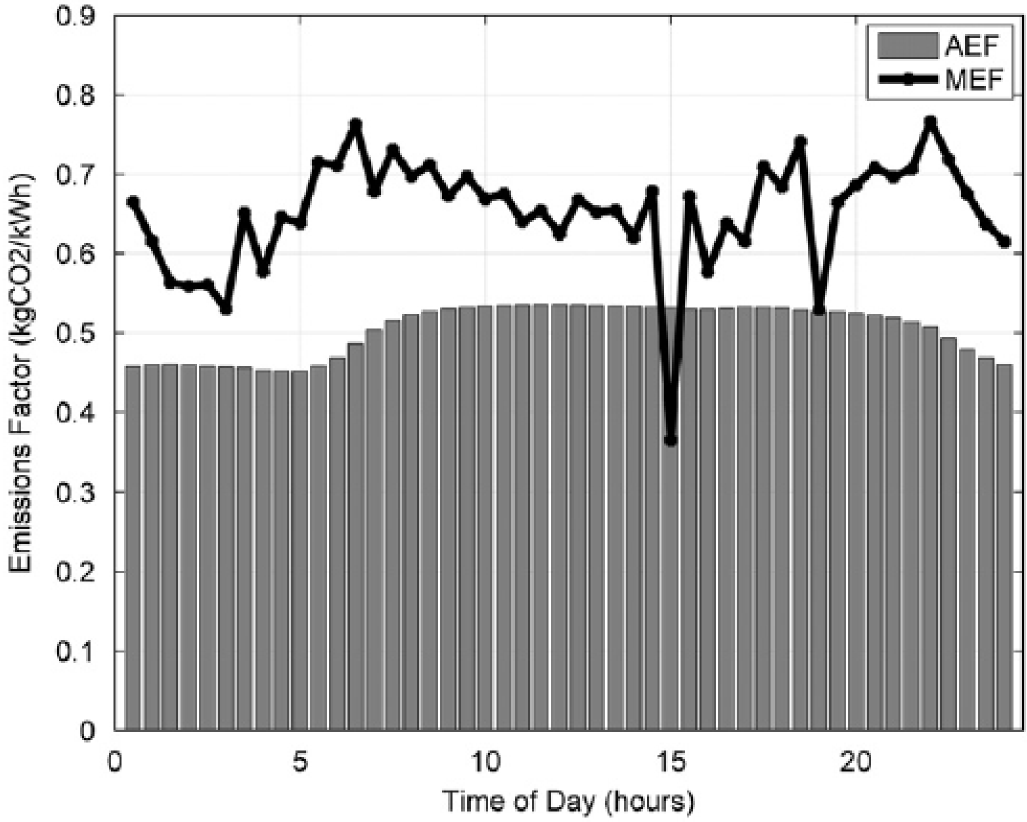

Figure 6. Marginal Emissions Factor and Average Emissions Factor as a Function of Time of Use in Great Britain, Calendar Years 2002 to 2009[20]

In some electricity systems, there can be little variation in the average emissions factor during the day. Figure 7 (page 10) shows the annual average emissions factor in Spain over a three year period. The emissions factor remains relatively constant throughout the day with a maximum variability of +/- 3.4%.

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[19] Hawkes, A. D. (in press). Estimating marginal CO_2 emissions rates for national electricity systems. *Energy Policy*.

[20] Hawkes (in press). *Op cit*, p 7.

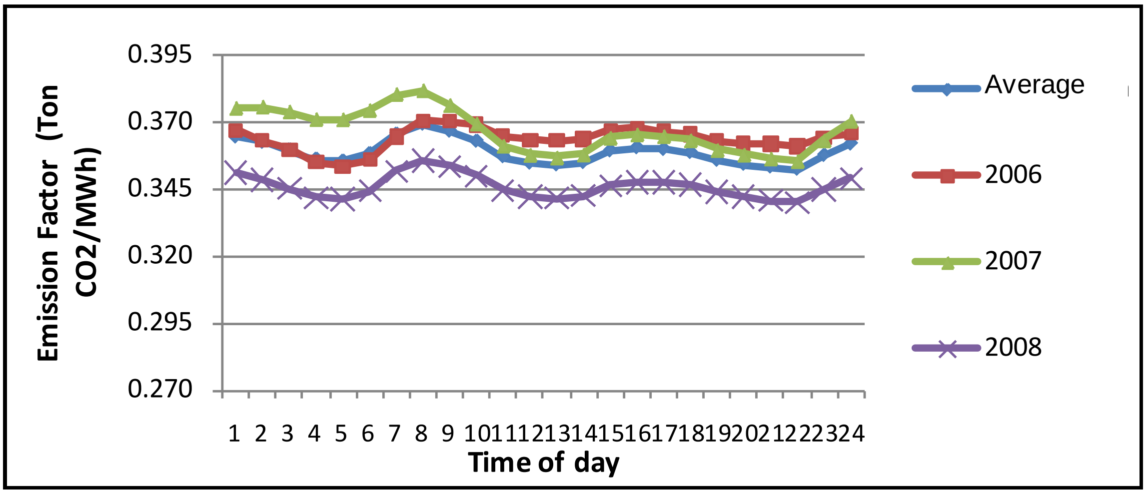

Figure 7. Average Emissions Factor in the Spanish Electricity System, 2006 to 2008[21]

These studies demonstrate that the greenhouse gas emissions intensity of electricity supplied to end-users varies with the time of day, with the days of the week, and with seasons. These variations are relatively small and are specific to different electricity systems depending on the generation mix in each system. The variations can be significant for some common end-uses that occur mainly at certain times of the day (eg lighting). The variations can also be significant for certain facilities that use large quantities of electricity at particular times of day (eg water supply pumping facilities), and/or on specific days of the week (eg sporting venues), and/or during certain times of the year (eg agricultural facilities such as sugar mills and cotton gins).

3.2 Methods for Estimating OM Emission Reductions

In principle, estimating emissions reductions achieved by a project activity is relatively simple. The calculation involves multiplying the quantity of electrical energy savings achieved through the project activity by the relevant emissions factor.

The general formula for this calculation is:

$$\mathbf{ER = Q*EF}$$

where ER is the emissions reduction (in tCO_2–e);

Q is the reduction in electricity consumption as compared with the baseline (in MWh),

and EF is the emissions factor (in tCO_2–e/MWh).

In the case of OM emissions, the emissions factor used should be for the power plant providing electricity at the margin during times when the project activity is operating (ie the marginal emissions factor).

In practice, estimating Operating Margin emission reductions can be a complex process. The ideal method would be to identify precisely which power plants on a grid are backed down in response to a project activity's operation and calculate emissions factors for

[21] Red Eléctrica de España (2008). *Analysis of the CO2 Emissions Factor*. Presentation for IEA DSM Programme Task XVIII. Madrid, REE.

those particular power plants. In practice, identifying marginal power plants is very difficult to do because of the large quantities of data required, and problems in gaining access to this data.

In response to these practical difficulties, a range of methods has been developed to estimate OM emissions. There are two main categories of methods that vary in the rigour with which they estimate emissions:

- methods estimating average emissions factors which require smaller quantities of data and are less rigorous;
- methods estimating marginal emissions factors which require larger quantities of data and are more rigorous.

There are five different types of methods for estimating OM emissions[22]. In order of increasing rigour, the methods are:

- **Average grid emissions**—This method calculates the average emissions from all power plants supplying the grid.
- **Marginal load-following emissions**—This method calculates the emissions of all load-following power plants supplying the grid.
- **Marginal weighted emissions**—This method uses a load-duration curve analysis to calculate weighted emissions of different types of power plants (based on fuel type) that are on the margin for specific time periods.
- **Marginal historic emissions**—This method uses an analysis of historical data (ie a dispatch decrement analysis) to determine a marginal emissions factor for each hour the project activity operates.
- **Marginal modelled emissions**—This method uses dispatch modelling to determine marginal emissions for each hour the project activity operates.

3.2.1 Average Grid Emissions

This method calculates an average emissions factor by dividing the total GHG emissions from all power plants supplying the grid by the total MWh of generation over a given time period (typically one year).

An average grid emissions factor is easy to calculate, but it provides only a rough approximation of OM emissions displaced by a project activity[23]. In particular, it does not account for the variation of OM emissions over time. Calculating a simple average emissions factor may be necessary in situations where data are not available to perform one of the marginal emissions factor methods described below. Because calculating a simple average is significantly less precise than other methods, it should only be used where other methods are not practicable.

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22 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 55.

23 *Ibid.*

Despite this lack of precision, an average grid emissions factor is used in one of the first operational emissions trading schemes in the world, the Greenhouse Gas Reduction Scheme (GGAS) that commenced operation in January 2003 in New South Wales, Australia. Each year, the GGAS Scheme Administrator calculates a "NSW pool coefficient"[24]. This is an indicator of the quantity of greenhouse gases (in tCO_2-e) emitted per MWh of electricity supplied from the 'pool' of major power plants serving the NSW electricity grid. The pool coefficient varies from one calendar year to the next. It is used both to calculate the emissions attributable to parties obligated under GGAS to reduce emissions (mainly electricity retailers) and to calculate the emission reductions achieved by individual emissions mitigation projects. Project implementers may create tradeable certificates equivalent to the emission reductions achieved by their projects.

Calculating an average grid emissions factor is also the general method used to estimate emission reductions achieved by projects implemented under the Clean Development Mechanism (CDM) established by the Kyoto Protocol[25].

3.2.2 Marginal Load-following Emissions

This method calculates a marginal emissions factor by averaging the emissions factors all load-following power plants, ie plants that are not baseload or must-run (including must-run generators based on intermittent resources such as wind). The emissions factor is calculated by dividing the total GHG emissions from load following power plants by the total MWh of generation by the same power plants over a given time period (typically one year).

The logic behind this method is that an emissions mitigation project is likely to avoid generation from a load-following power plant rather than generation from a baseload or must-run plant. The advantage of the method is that it is easy to perform and requires minimal amounts of data. However, the result is an average emissions factor of load-following plants, which may or may not accurately reflect the emissions factors of the power plants that are actually on the margin during the period that a project activity is operating[26].

There are two ways in which the emissions factor of all load-following power plants can be calculated[27].

- The first calculation method requires obtaining data on all power plants on the grid that do not provide baseload or must-run power. It is usually necessary to consult with the grid operator to identify baseload, must-run, and intermittent plants for exclusion. Once the load-following plants have been identified, the average load following emissions factor of these plants can be calculated.

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24 Crossley, D.J. (2008b). Tradeable energy efficiency certificates in Australia. *Energy Efficiency* **1**, 267–281.

25 CDM Executive Board (2009). *Tool to Calculate the Emission Factor for an Electricity System*. Bonn, CDM Executive Board.

26 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 58.

27 *Ibid.*

- The second calculation method requires aggregate information on power generation by fuel type and avoids the need for data on individual power plants. The approach is to rank megawatt-hours of generation by the average cost or capacity factor associated with each fuel type (see Figure 8). The average load following emissions factor can then be calculated as the average emissions factor of the top third[28] (highest cost or lowest capacity factor) of ranked megawatt-hours.

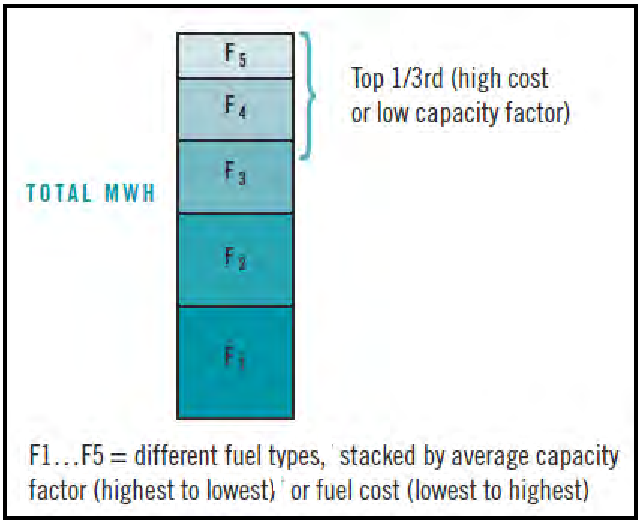

Figure 8. Calculating Average Load-following Emissions Factor from Data on Generation by Fuel Types[29]

The Marginal Load-following Emissions method is used by the New England Independent System Operator (ISO-NE) in the United States to calculate emissions from marginal power plants, referred to as *marginal fossil units*[30]. This subset of power plants on the ISO-NE system is comprised of those fossil units that are fuelled with oil (including distillate, residual, diesel and jet fuel), and/or natural gas. Fossil units fuelled with coal, wood, biomass, or refuse/landfill gas are excluded from the calculation as they typically operate as baseload units and would not be dispatched to higher levels in the event of higher load on the system. Hydro, wind, and nuclear units are also excluded from the marginal calculation.

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[28] Selecting the top third of ranked megawatt-hours is an arbitrary rule of thumb. However, it was recommended in the Grid-connected Guidelines based on the expert opinion of the stakeholders who reviewed the Guidelines.

[29] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 59.

[30] ISO New England (2008). *2006 New England Marginal Emission Rate Analysis*. Holyoke, MA, ISO-NE.

3.2.3 Marginal Weighted Emissions

This method calculates a marginal emissions factor by averaging the emissions factors of different types of power plants (by fuel type), weighted according to the length of time these plants actually provide power on the margin. The length of time on the margin is determined through a load duration curve analysis, which reveals the types of power plants that were used to meet peak system loads over a specific time period.

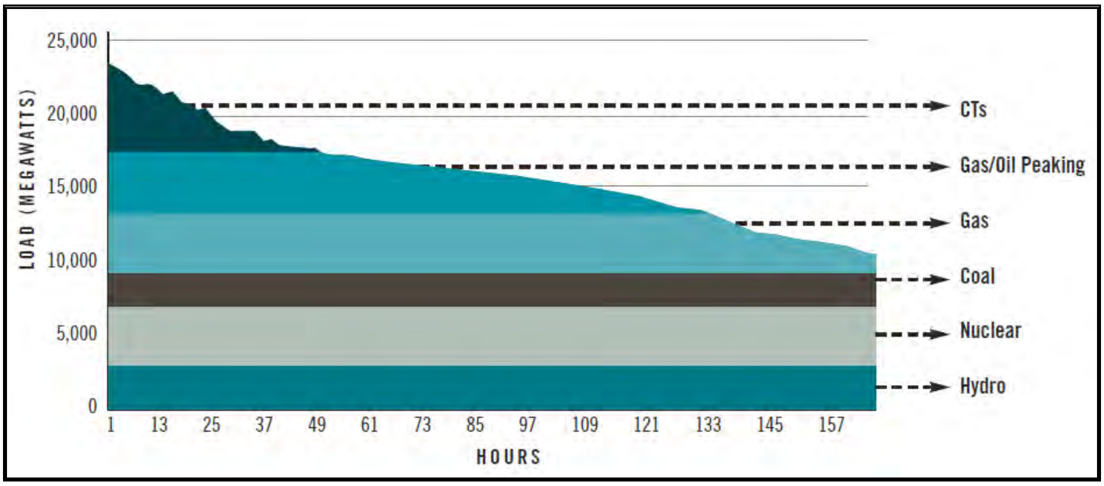

Figure 9. Example of a Weekly Load Duration Curve "Filled" with Generation by Type of Power Plant[31]

Figure 9 is an example of a load duration curve, showing the time (in hours) that different types of power plants were used to generate electricity over a week. Each type of plant that intersects the load-duration curve was on the margin for a proportion of the week covered by the load duration curve. Plant types that do not intersect the curve were not on the margin at any time during the week, ie they supplied baseload power.

The number of hours that a particular power plant type was on the margin can be determined by the difference between the highest and lowest numbered hour for which the power plant type intersects the load duration curve. For example, in Figure 9, gas/oil peaking plants intersect the load duration curve at hour 49 and hour 133; therefore these plants were on the margin for 84 hours out of the total of 168 hours in the week, ie 50% of the time.

To calculate the marginal weighted emissions factor, the individual emissions factors for each type of power plant on the margin are calculated and then multiplied by the proportion of time each plant type was on the margin. For example, in the case shown in Figure 8, the emissions factor for gas/oil peaking plants would be multiplied by 0.5.

[31] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 62.

The level of detail required for this analysis can vary, as can some of the specifics for determining marginal power plants. Key variables include[32]:

- **Time periods**—Load-duration curve analyses can be used to calculate an annual marginal weighted emissions factor using an entire year's worth of data, or to calculate emission factors using data for shorter time periods. Emission factors calculated for shorter periods will generally be more accurate, especially where marginal power plants are expected to vary significantly over the year (eg by week, month, or season), or if a project activity is expected to be operating only in certain time periods (eg energy efficient lighting).
- **Distinctions between types of power plants**—Accuracy will be improved by distinguishing multiple types of power plants and their associated emission rates and times on the margin. Distinctions between types of plants can be made by fuel and/or by function (eg baseload plants, peaking plants, etc.).
- **Ranking criteria**—With a load-duration curve analysis, different types of power plants are assigned an overall dispatch priority rank in order to determine which plants are used to meet different load levels. Typically, plants are ranked by average operating cost. However, where cost data are not available (or where other criteria play a significant role in dispatch priorities), other ranking criteria may be used.

3.2.4 Marginal Historical Emissions

This method involves an analysis of historical data to determine which power plants were in the dispatch order for the grid during each hour of a year. A project activity's operation can then be matched to the marginal generation mix in each hour to calculate an emissions factor for generation displaced by the project. Ideally, this analysis is done with historical data derived from the same time period over which the project activity operates (*ex post* analysis), although it can also be done, with less accuracy, using prior year data matched to project activity in the current year (*ex ante* analysis).

The basic approach involves using historical data to determine the amount of generation (in MWh) from each power plant on the grid for each hour in which the project activity operates and the merit order of dispatch for each power plant. These data must usually be obtained from the grid or market operator. The main factor determining the merit order in which power plants are dispatched is the cost of generation, with the power plants with the lowest cost of generation being dispatched first and the highest cost plants being dispatched only when required to meet the load (typically during times of peak load).

To carry out the analysis, the generation output from each power plant in each hour is "stacked" in a graph according to the merit order. Figure 10 (page 16) shows an example of such a stacked graph in which each colour represents a different power plant.

[32] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 62.

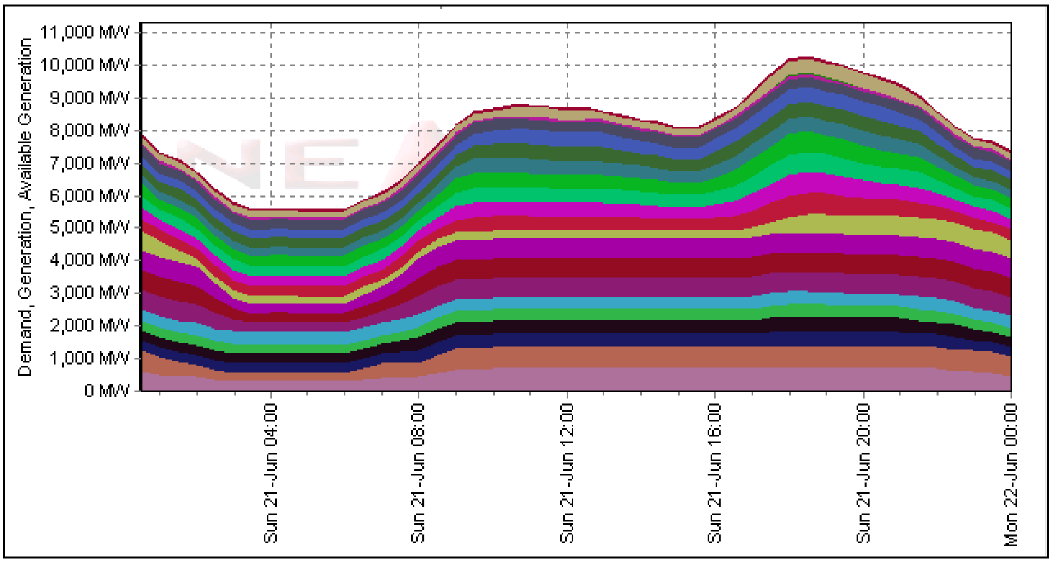

Figure 10. Example of Generation Output Stacked by Merit Order[33]

The OM emissions reductions from the generation displaced by the project activity can then be calculated. There are two ways in which this can be done[34]:

- the generation displaced by the project activity in each hour can be matched to an equal amount of generation at the top of the dispatch order (excluding must-run power plants[35]), and the weighted average emissions of this generation calculated using the emissions factors for each individual power plant supplying the generation;
- the average emissions factor of power plants supplying the top 10 percent of generation in each hour (excluding must-run power plants), as determined by the dispatch merit order, can be calculated and then used to calculate OM emissions reductions from the generation displaced by the project activity.

The second method is generally preferred, since the apparent precision of the first method can be somewhat illusory depending on whether the available data records the way that power plants are actually dispatched, including any variations from the merit order. Such variations occur because, in practice, plant dispatch is more complicated than the simple merit order determined by the cost of generation[36].

First, system operators do not treat individual power plants as single entities in the dispatch process. In competitive markets, plant owners typically bid generating units in several blocks (at different prices) rather than as a single block of capacity. These bids reflect the unit's efficiency at different output levels, the unit's low operating limit

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33 Prepared with data on actual historical generation available from the relevant market operator. Each colour represents a different power plant.

34 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 64.

35 Must-run power plants would not be backed off in response to load reductions resulting from the operation of project activities. Therefore they must be excluded from the calculation of OM emission reductions.

36 Keith, G. and Biewald, B. (2005). *Methods for Estimating Emissions Avoided by Renewable Energy and Energy Efficiency*. Cambridge, Massachusetts, Synapse Energy Economics Inc.

(below which the owner will not run the plant) and the owner's bidding strategy. Consequently, the supply curve consists of many blocks of generating capacity, not entire power plants, and the blocks from a given plant can be at different places in the curve.

Second, it is time consuming to start and stop large generating units, and limitations on unit ramp rates force system operators to keep some units running during periods when they are not needed, in order to have the units available when they are needed. In such cases, units are said to be running "out of merit order".

Finally, transmission constraints may also require operators to dispatch certain units out of merit order, ie a more expensive unit may be dispatched when less expensive units are available because transmission constraints prevent the cheaper units from serving the load.

3.2.5 Marginal Modelled Emissions

This method uses a model of the grid electricity system to simulate the dispatch of power plants under typical operating conditions. Globally, a number of models are available for this purpose and they can be used and applied in different ways.

There are two basic approaches to this type of dispatch modelling[37]:

- a "generic" modelling run for the grid can be used to calculate a typical OM emissions factor for each hour in which the project activity displaces generation. This approach is analogous to the marginal historic emissions method, but relies on modelled rather than actual historical dispatch and generation data;
- separate modelling runs can be done that simulate grid operation under identical circumstances with and without the project activity. OM emissions of generation displaced by the project activity are estimated by comparing the results of the modelling runs.

The second approach requires more effort and produces project-specific results, so it generally used only for large project activities.

3.3 Accounting for Electricity Imports

Each method for estimating the OM emissions reductions from the generation displaced by the project activity requires a definition of the grid boundary where the project activity is located. The grid boundary will determine which power plants' emissions are factored into the calculation of the OM emissions factor.

Generation on a grid must be coordinated in order for it to function properly, so a central grid operator is required to dispatch power plants in accordance with engineering and economic constraints. Consequently, the simplest way to define grid boundaries (that also accords with practical reality) is by the set of power plants and transmission lines under the control of a single grid operator. In most cases, determining the appropriate grid boundary should be straightforward since the data will be provided by the grid or market operator.

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[37] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 65.

In addition to the electricity generated on the local grid, the project activity may sometimes displace electricity imported from neighbouring grids. As a general rule, if power imports constitute 5 percent or more of the total generation consumed on the local grid, then these imports should be factored into the calculation of the OM emission factor[38].

Specific procedures for factoring in electricity imports will depend on the type of method used to calculate the OM emissions factor. There are two general steps for dealing with imports[39].

The *emissions factor* for imported electricity can be determined using any of the same methods used to calculate the OM emission factor for the local grid. In practice, it may not be worthwhile to expend the same level of effort. In most cases, using the average load-following emissions method will be appropriate.

It is reasonable to assume that the *proportion of imported electricity that is on the margin* is 100% (ie all imported electricity is load following) unless these imports constitute more than 20 percent of total generation on the local grid[40]. If this 20 percent threshold is exceeded, it will be necessary to consult with grid operators to determine what portion of the imports can be considered baseload and therefore excluded from OM emission factor calculations.

3.4 Choosing Between Methods

3.4.1 Comparison Between Methods

Studies that have used several methods to estimate average and marginal emissions factors have reported significant differences between methods in the results obtained. For example, a study in California by Lawrence Berkeley National Laboratory[41] found that:

- differentiating between marginal and average emissions is essential to accurately estimate the CO_2 savings from reducing electricity use;
- careful effort is required to interpret and apply the results of the Marginal Modelled Emissions method, including matching of historic data, checking and standardising of emission data, and modelling of imports, exports, and trades;
- the Marginal Weighted Emissions was the most promising of the three methods used.

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38 The 5 percent threshold for considering imports is recommended based on the expert opinion of the stakeholders who reviewed the Grid-connected Guidelines. It is not a “scientific” number and should be used as a general rule of thumb.

39 World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 57.

40 The 20 percent threshold for treating imports as load following is recommended based on the expert opinion of the stakeholders who reviewed the Grid-connected Guidelines.

41 Marnay, C., Fisher, D., Murtishaw, S., Phadke, A., Price, L., Sathaye, J. (2002). *Estimating Carbon Dioxide Emissions Factors for the California Electric Power Sector*. Berkeley, California, LBNL.

Keith and Biewald[42] concluded that Marginal Weighted Emissions and Marginal Historical Emissions are reasonable methods for making rough estimates of displaced emissions. However, both of these methods make simplifying assumptions about plant dispatch, a critical dynamic in displaced emissions. The authors do not recommend these methods for situations in which a high level of accuracy is needed.

Keith and Biewald do recommend a method based on hourly operation and emissions data from fossil-fuelled generators collected in five-minute intervals from Continuous Emissions Monitors (CEMS) at power plants[43]. This method is extremely credible in that it captures the actual dispatch of these generators, giving the method an empirical basis which the other methods do not have. However, this method does not account for situations in which hydro generation or imported energy are on the margin. In grid regions where hydro units and imported energy are rarely used to follow load, this method would generate highly accurate estimates of displacement. In regions where hydro units and imported energy are regularly used to follow load, the method would be less accurate.

3.4.2 Relevant Timeframe

One factor that is important in choosing an appropriate method to estimate average and marginal emissions factors is the timeframe over which the method is intended to operate. Hawkes[44] has identified three timeframes that are important:

1. **Short-term 'balancing' impact —** seconds to 90 minutes ahead.
2. **Systematic energy trading impact —** typically, energy is traded one hour to one year ahead.
3. **Long-term infrastructure impact —** five to 15 years ahead.

Short term impacts relate to the elements of the existing electricity system that respond to unpredictable changes in demand. These can be very short-lived responses, stemming from events such as intermittency of some generator types or unplanned power plant outage, where the system operator performs actions to balance the system in real time.

In contrast, systematic impacts relate to changes in the supply mix that occur after a predictable change in demand, where (for example) the specific power plants on line at a particular time change due to a consistent change in aggregate demand.

Finally, long-term systematic changes in demand can also lead to particular infrastructure investment choices, where alternative technologies may be chosen or investment deferred or avoided based on consistent long-term changes in demand. Examples of long-term infrastructure impacts include deferring the building of a new power plant, electricity line or substation due to insufficient increase in peak electricity demand.

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[42] Keith, G. and Biewald, B. (2005). *Op. cit*., p 2.

[43] This method is not otherwise considered in this report because installation of Continuous Emissions Monitors at power plants is not common outside the United States.

[44] Hawkes (in press). *Op cit*, p 2.

3.4.3 Selection Criteria

In choosing one or more methods for estimating the OM emissions reductions achieved by a project, the following selection criteria should be kept in mind[45].

- **Relevance**—The method chosen should be appropriate for the context in which the estimate of the OM emissions reductions will be used. Relevance can be determined by asking whether the emissions reductions should be estimated with greater rigour or greater transparency, or by a method with the greatest ease-of-use?
- **Completeness**—The method chosen should be able to be used with readily available data.
- **Consistency—**The method chosen should be able to be consistently applied and reproduced over time in the context where the project activity is operating and should also be consistent with the method(s) used by other relevant grid-based GHG.
- **Transparency—**The method chosen should be transparent for relevant stakeholders and the data used by the method should be easily accessible and open to review by the stakeholders.
- **Accuracy**—The method chosen should be the most accurate possible, given data constraints and the need for consistency, transparency and relevance to the project activity's context. Generally, the more rigorous methods will be more accurate.
- **Conservativeness**—Where data and resources allow, OM emissions reductions should be estimated by using several methods and choosing the most conservative (lowest) result.

4. EXAMPLE CALCULATIONS OF EMISSIONS REDUCTIONS

Following are calculations of emission reductions achieved by four DSM projects. However, the calculations should not be regarded as definitive. Instead they should be regarded as illustrative examples of methods that could be used in real world situations.

4.1 Methodology

4.1.1 DSM Projects

The four DSM projects selected for the calculation of emissions reductions are all Task XVIII case studies from Australia. Australian DSM projects were selected because a comprehensive suite of data from the Australian National Electricity Market is readily available[46]. The projects are as follows:

- **DSM-AU01 ETSA Utilities Air Conditioner Direct Load Control Program**. This demand response program carried out cycling of residential air conditioners to reduce load at peak times on the electricity network.

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[45] World Business Council for Sustainable Development and World Resources Institute (2007). *Op. cit.*, p 55.

[46] Unfortunately, comparable data were not readily for the case studies from other countries

- **DSM-AU02 Drummoyne Demand Management Program**. This energy efficiency program replaced incandescent lamps with compact florescent lamps in residential and small commercial premises located in a geographical area served by a substation that was close to its maximum rated demand.
- **DSM-AU03 Binda-Bigga Demand Management Project**. This fuel substitution project replaced electrical cooking and room heating appliances with gas appliances in a rural area served by a network feeder that was subject to voltage fluctuations.
- **DSM-AU04 Castle Hill Demand Management Program**. This program implemented energy efficiency measures in a commercial sector shopping sector located in a geographical area served by a substation that was close to its maximum rated demand.

4.1.2 Electricity Market Data

Calculating emissions reductions achieved by the DSM projects involved tracking changes in the generation mix in two regions of the Australian National Electricity Market (NEM). The structure of the NEM is shown in Figure 11 (page 22). A striking feature of the NEM is that the individual regions are interconnected by a small number of transmission lines of relatively low capacity compared with the total generation capacity of each region.

A comprehensive suite of data about the operation of the NEM can be obtained from the Australian Energy Market Operator (AEMO). AEMO data used in the calculation of the emissions reductions were supplied by Global-Roam Pty Ltd with their computer software program *NEM-Review*[47]. Emissions factors (tCO2-e/MWh) for relevant marginal power plants were obtained from a report by ACIL Tasman[48].

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47 Information about *NEM-Review* is available at: http://v6.nem-review.info/.

48 ACIL Tasman Pty Ltd (2009). *Fuel Resource, New Entry and Generation Costs in the NEM*. Brisbane, ACIL Tasman.

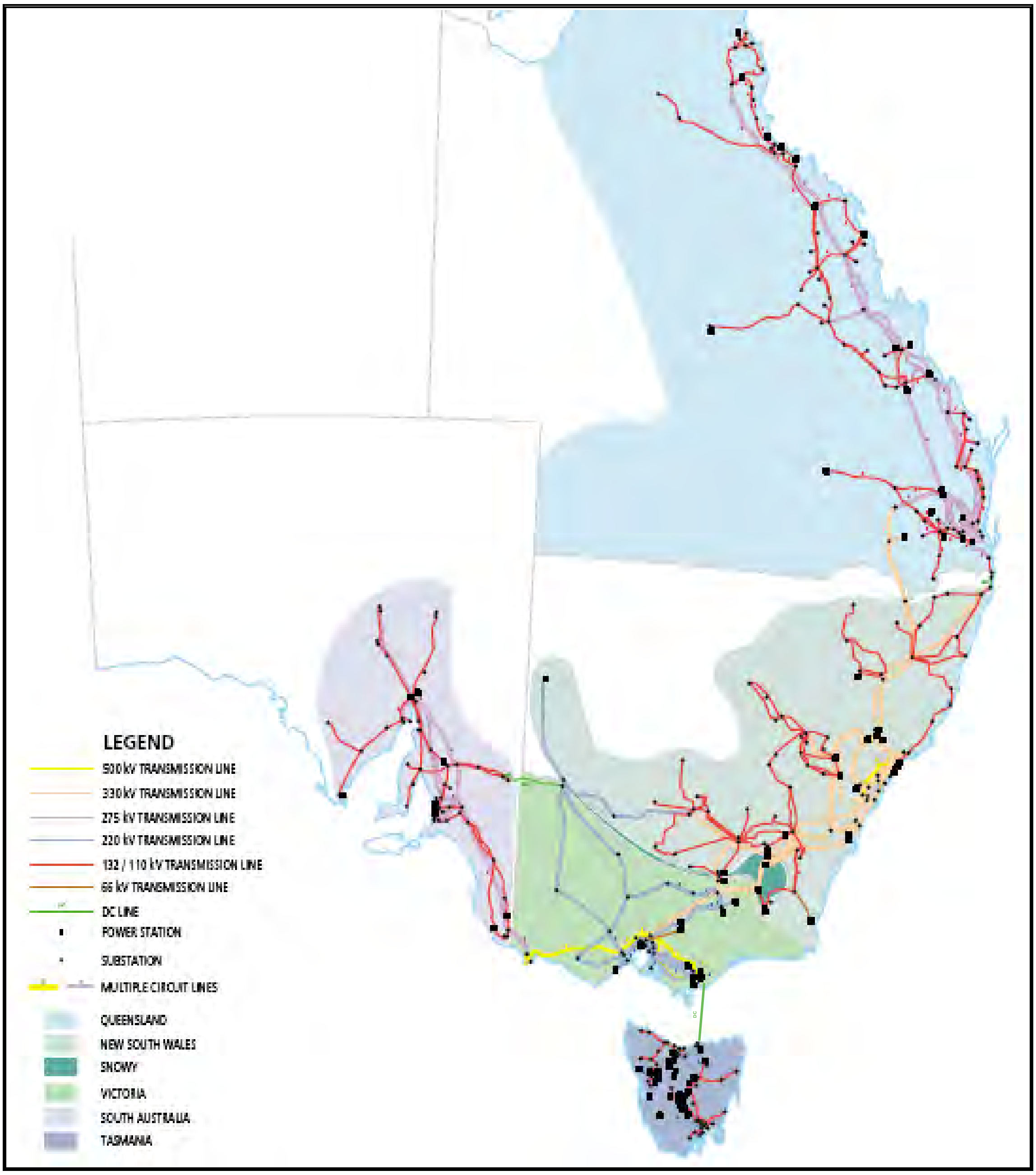

Figure 11. The Australian National Electricity Market (NEM)

4.1.3 Calculation of Emissions Reductions

The calculation of emissions reductions achieved by each of the four DSM projects was calculated by two methods:

- the Average Grid Emissions method; and
- a method based on the Marginal Historical Emissions method, modified to work with the available data.

In addition, a method was devised to account for losses in the transmission and distribution systems.

4.1.3.1 Average Grid Emissions Method

The reduction in greenhouse gas emissions resulting from a project was calculated by multiplying the energy saving achieved by the project by the average grid emissions factor for the relevant region of the Australian National Electricity Market obtained from a handbook of emissions factors published by the Australian (federal) Government[49].

4.1.3.2 Modified Marginal Historical Emissions Method

Historical data were obtained of the electrical energy (MWh) sent out daily by each major power plant located in the NEM region in which the DSM project being considered was located. The *NEM-Review* program was used to tabulate the energy sent out data in each of the 48 daily half hour trading periods in the NEM.

The marginal power plant for each day was identified by visual inspection of the table of generation output data for the time period over which the DSM measures in the project were operating[50]. The table showed which power plants had varying generation output during the selected time period. Ignoring must-run power plants, the plant with the most varied output was determined to be the marginal plant. Most power plants had steady generation output over the time period selected. Only plants with varying output would be backed off in response to load reductions resulting from the operation of DSM measures.

When the marginal power plant changed during the time period that the DSM measures were operating, the marginal plant was deemed to be the plant that was on the margin for the longest proportion of the period.

The quantity of electrical energy (MWh) displaced by the DSM measures over the relevant time period was then multiplied by the emissions factor for the marginal power plant (tCO_2-e/MWh) to give the daily emissions reductions achieved by the project.

An example of the methodology used to identify marginal power plants is shown in Table 1 (page 25). This table shows generation in South Australia on 28 January 2009, a particularly hot day with a maximum temperature of 45.7 ^{o}C. The project DSM measures were operating

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[49] Department of Climate Change (2010). *National Greenhouse Accounts (NGA) Factors*. Canberra, DCC.

[50] Graphs of power plant generation stacked in merit order could not be used to identify marginal power plants because the current version of the *NEM-Review* software (version 6.2) does not include market bidding data for individual power plants and therefore could not be used to produce such graphs. The software developer Global-Roam Pty Ltd advises that it is intended to include market bidding data in later versions of the *NEM-Review* software.

between 1.00 pm and 5.00 pm on this day (shaded in Table 1). Ignoring must-run wind farms, there were three power plants with varying generation output during this period: Dry Creek, Torrens Island A and Torrens Island B. Torrens Island A was determined to be the marginal power plant because it had the most variable output.

This calculation method does not account for imports from other NEM regions. This could affect the calculation of emissions reductions if the generation outputs from all of the power stations in the region are steady during the relevant time period and the level of imports is varying. In this situation imports are effectively on the margin.

4.1.3.3 Accounting for Transmission and Distribution Losses

The emissions factor used in the Average Grid Emissions method included an allowance for losses in the transmission and distribution system. However, the calculations in the Modified Marginal Historical Emissions Method were based on energy savings at the point of end-use. To account for transmission and distribution losses, the values for energy saved were increased by the following loss factors[51]:

- South Australia: 6.7%;
- New South Wales: 7.5%

[51] George Wilkenfeld and Associates (2002). *Regulatory Impact Statement: Minimum Energy Performance Standards and Alternative Strategies for Electricity Distribution Transformers*. Sydney, GWA.

Table 1. Generation in the South Australian Region of the Australian National Electricity Market on 28 January 2009[52]

Time at End of Settlement Period	Angaston	Dry Creek	Hallett	Hallett Wind Farm	Ladbroke Grove	Lake Bonney 2 Wind Farm	Mintaro	Northern	Osborne	Pelican Point	Playford B	Port Lincoln	Quarantine	Snowtown Wind Farm	Snuggery	Torrens Island A	Torrens Island B
0:30	0	0	0	13	0	53	0	541	155	430	125	0	44	55	0	100	180
1:00	0	0	0	12	0	70	0	540	148	393	125	0	44	58	0	100	180
1:30	0	0	0	21	0	77	0	540	140	363	125	0	44	67	0	100	180
2:00	0	0	0	27	0	81	0	517	130	350	125	0	44	63	0	100	120
2:30	0	0	0	30	0	71	0	480	119	350	129	0	44	63	0	100	120
3:00	0	0	0	28	0	63	0	480	117	350	143	0	44	62	0	100	120
3:30	0	0	0	31	0	49	0	480	117	350	145	0	44	66	0	100	120
4:00	0	0	0	47	0	44	0	480	117	350	145	0	44	68	0	100	121
4:30	0	0	0	60	0	67	0	480	126	350	140	0	40	72	0	100	120
5:00	0	0	0	46	0	79	0	486	133	350	140	0	40	73	0	100	120
5:30	0	0	0	42	0	80	0	531	133	350	140	0	40	74	0	100	120
6:00	0	0	0	49	0	73	0	540	138	404	142	0	40	73	0	100	184
6:30	0	0	0	55	0	54	0	542	154	443	145	0	40	72	0	100	190
7:00	0	0	0	56	0	63	0	540	147	454	147	0	40	73	0	100	266
7:30	0	0	0	60	16	64	0	540	146	454	150	0	68	74	0	150	208
8:00	0	0	0	64	73	69	0	540	145	454	150	0	80	70	0	159	201
8:30	0	0	0	55	78	70	0	540	145	454	150	0	80	74	0	177	326
9:00	0	0	0	67	76	70	0	540	155	454	150	0	78	62	0	260	408
9:30	0	0	0	75	72	56	0	540	180	454	150	0	78	53	0	280	425
10:00	0	0	31	68	72	38	0	540	183	454	153	0	78	50	0	281	443
10:30	0	0	55	56	72	27	0	540	183	454	155	0	74	45	0	281	514
11:00	0	9	75	51	72	20	0	540	183	454	155	0	74	36	0	282	574
11:30	0	19	83	50	72	12	20	540	183	451	155	0	73	38	0	292	672

52 Prepared with the *NEM-Review* software program using data on actual historical generation in the Australian National Electricity Market from the market operator.

Tine at End of Settlement Period	Angaston	Dry Creek	Hallett	Hallett Wind Farm	Ladbroke Grove	Lake Bonney 2 Wind Farm	Mintaro	Northern	Osborne	Pelican Point	Playford B	Port Lincoln	Quarantine	Snowtown Wind Farm	Snuggery	Torrens Island A	Torrens Island B
12:00	0	26	120	39	72	20	30	539	183	445	152	0	71	46	0	300	719
12:30	0	51	132	28	68	27	50	540	183	445	150	10	71	70	24	300	725
13:00	0	104	145	14	68	31	56	540	184	445	150	24	74	66	36	293	730
13:30	29	101	145	3	68	20	69	541	184	446	152	23	74	67	36	289	715
14:00	50	114	145	0	68	14	69	540	182	448	150	30	74	57	36	300	694
14:30	50	126	145	0	68	27	69	541	182	449	150	40	74	55	36	307	695
15:00	50	124	145	0	68	34	68	540	182	448	150	43	74	56	37	333	657
15:30	50	123	145	0	68	10	69	541	182	448	150	43	74	55	37	356	683
16:00	50	122	145	0	68	4	70	541	182	447	150	43	74	50	37	379	656
16:30	50	119	145	0	68	4	71	541	182	449	150	43	74	38	37	363	657
17:00	50	119	145	0	68	3	71	540	182	450	150	43	76	25	37	387	597
17:30	50	80	127	0	72	4	70	541	182	451	150	24	76	15	37	350	716
18:00	0	69	149	2	74	9	68	538	182	449	142	18	74	3	18	358	745
18:30	0	119	145	5	74	16	64	531	180	445	130	43	75	2	15	298	637
19:00	0	119	117	5	74	22	69	530	180	445	130	43	75	19	0	274	570
19:30	0	71	115	4	74	33	72	530	182	445	130	7	75	66	0	287	560
20:00	0	43	75	5	76	38	42	530	183	445	130	0	75	85	0	324	568
20:30	0	45	70	5	76	33	30	530	184	445	130	0	75	84	0	319	569
21:00	0	15	53	4	76	32	30	530	184	445	130	0	75	76	0	317	576
21:30	0	0	50	4	76	32	0	530	184	445	130	0	75	69	0	301	524
22:00	0	0	50	4	76	35	0	530	185	445	130	0	75	69	0	259	444
22:30	0	0	34	3	76	41	0	506	187	445	130	0	75	46	0	220	420
23:00	0	0	0	5	76	23	0	467	178	445	130	0	75	30	0	203	402
23:30	0	0	0	4	76	23	0	436	182	445	130	0	75	23	0	190	413
0:00	0	0	0	5	76	29	0	446	176	445	130	0	75	22	0	176	384

4.2 ETSA Utilities Air Conditioner Direct Load Control Program

4.2.1 Project Description

ETSA Utilities is the sole distributor of electricity in the State of South Australia, serving over 800,000 customers with a distribution network covering 178,000 square kilometres.

South Australia has a very peaky electricity demand profile. The major contribution to the peak is from the residential sector, particularly air conditioning use on hot days. ETSA Utilities estimates that peak demand on hot days, primarily due to air-conditioning load, is about 1,000 MW higher than average daily peak demand over the summer.

In September 2003, the electricity industry regulator, the Essential Services Commission of South Australia (ESCOSA), approved an amount of AUD20.4 million (December 2004 values) as operating expenditure over the 2005-2010 regulatory period for ETSA Utilities to trial specified DSM measures that may reduce the requirement for peak-driven network expansion.

One of the DSM measures investigated by ETSA Utilities was the application of direct load control technologies to carry out cycling of residential air conditioners during a time period coinciding with the system peak. Between 2006 and 2008, ETSA Utilities carried out several trials of air conditioner cycling in about 1000 residential properties in various suburbs of Adelaide.

Cycling involved air conditioner compressors being switched off (with fans continuing to operate) for various periods during the afternoon on hot days. A typical cycling strategy involved compressors being switched off for 15 minutes and then on for 15 minutes over a four hour period. The switching was staggered across different groups of air conditioners and this diversity achieved a fairly steady peak load reduction of about 2.2 MVA over the four hour period.

4.2.2 Example Calculation of Emissions Reduction

The example calculation was carried out for the six month period from October 2008 to March 2009 (spring and summer in the southern hemisphere). We assumed that air conditioner cycling was carried out on all hot days during this period with maximum temperatures of 30^{o}C or more. Cycling of air conditioners was assumed to occur between 1.00 pm and 5.00 pm, achieving a load reduction of 2.2 MVA (2.34 MVA including losses) throughout these four hours.

4.2.2.1 Average Grid Emissions Method

Shown below is an example calculation, using the Average Grid Emissions Method. of the total emissions reduction that would be achieved by the ETSA Utilities Air Conditioner Direct Load Control Program during the summer of 2008/09, based on the assumptions outlined above.

Total number of days with maximum temperatures of 30^{o}C or more: 52

Total energy saving achieved by the project (including losses): 486.7 MWh

Average grid emissions factor for South Australia: 0.72 tCO2-e/MWh

Emissions reduction achieved by the project: 350.4 tCO2-e

4.2.2.1 Modified Marginal Historical Emissions Method

Table 2 presents an example calculation, using the Modified Marginal Historical Emissions Method, of the total emissions reduction that would be achieved by the ETSA Utilities Air Conditioner Direct Load Control Program during the summer of 2008/09, based on the assumptions outlined above. The table shows the marginal power plant between 1.00 pm and 5.00 pm on each day between October 2008 and March 2009 with a maximum temperatures of 30°C or more. Table 2 also shows the emissions factors of each of these power plants and the corresponding daily emissions reductions resulting from load reductions of 2.34 MVA (including losses) during the four hour period 1.00 to 5.00 pm. The total emissions reduction that would be achieved from the ETSA Utilities program is shown at the bottom of the table.

Table 2. Example Calculation of Emissions Reduction Achieved by the ETSA Utilities Air Conditioner Direct Load Control Program

Date	Maximum Temperature (°C)	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
12-Oct-08	31.9	Osborne	0.6	2.34	4.0	5.62
17-Oct-08	31.0	Hallet	1.05	2.34	4.0	9.83
18-Oct-08	34.6	Playford B	1.51	2.34	4.0	14.13
24-Oct-08	30.9	Ladbroke Grove	0.84	2.34	4.0	7.86
25-Oct-08	34.7	Pelican Point	0.52	2.34	4.0	4.87
11-Nov-08	34.6	Torrens Island B	0.84	2.34	4.0	7.86
12-Nov-08	36.6	Hallet	1.05	2.34	4.0	9.83
25-Nov-08	31.5	Torrens Island B	0.84	2.34	4.0	7.86
20-Dec-08	30.5	Torrens Island B	0.84	2.34	4.0	7.86
21-Dec-08	34.5	Northern	0.95	2.34	4.0	8.89
24-Dec-08	30.1	Torrens Island B	0.84	2.34	4.0	7.86
25-Dec-08	30.8	Torrens Island B	0.84	2.34	4.0	7.86
26-Dec-08	33.6	Northern	0.84	2.34	4.0	7.86
4-Jan-09	33.3	Pelican Point	0.52	2.34	4.0	4.87
5-Jan-09	30.5	Torrens Island B	0.84	2.34	4.0	7.86
6-Jan-09	31.0	Northern	0.95	2.34	4.0	8.89
12-Jan-09	35.2	Torrens Island A	0.91	2.34	4.0	8.52
13-Jan-09	41.3	Port Lincoln	1.01	2.34	4.0	9.45
14-Jan-09	32.3	Osborne	0.6	2.34	4.0	5.62
18-Jan-09	32.9	Torrens Island B	0.84	2.34	4.0	7.86
19-Jan-09	38.5	Torrens Island A	0.91	2.34	4.0	8.52
20-Jan-09	36.9	Playford B	1.51	2.34	4.0	14.13
25-Jan-09	30.4	Torrens Island B	0.84	2.34	4.0	7.86
26-Jan-09	36.6	Torrens Island B	0.84	2.34	4.0	7.86
27-Jan-09	43.2	Mintaro	0.9	2.34	4.0	8.42
28-Jan-09	45.7	Torrens Island A	0.91	2.34	4.0	8.52
29-Jan-09	43.4	Dry Creek	0.97	2.34	4.0	9.08
30-Jan-09	43.1	Dry Creek	0.97	2.34	4.0	9.08
31-Jan-09	41.1	Mintaro	0.9	2.34	4.0	8.42
1-Feb-09	40.6	Northern	0.95	2.34	4.0	8.89
2-Feb-09	38.8	Torrens Island B	0.84	2.34	4.0	7.86
3-Feb-09	36.3	Northern	0.95	2.34	4.0	8.89
4-Feb-09	33.0	Torrens Island B	0.84	2.34	4.0	7.86
5-Feb-09	35.6	Torrens Island B	0.84	2.34	4.0	7.86

Date	Maximum Temperature (ºC)	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
6-Feb-09	43.9	Torrens Island B	0.84	2.34	4.0	7.86
7-Feb-09	41.5	Dry Creek	0.97	2.34	4.0	9.08
14-Feb-09	31.3	Torrens Island A	0.91	2.34	4.0	8.52
15-Feb-09	30.0	Northern	0.95	2.34	4.0	8.89
16-Feb-09	31.7	Torrens Island B	0.84	2.34	4.0	7.86
17-Feb-09	34.2	Torrens Island B	0.84	2.34	4.0	7.86
18-Feb-09	35.4	Torrens Island B	0.84	2.34	4.0	7.86
19-Feb-09	33.0	Torrens Island B	0.84	2.34	4.0	7.86
22-Feb-09	31.4	Pelican Point	0.52	2.34	4.0	4.87
25-Feb-09	32.4	Torrens Island A	0.91	2.34	4.0	8.52
26-Feb-09	38.4	Playford B	1.51	2.34	4.0	14.13
27-Feb-09	32.2	Torrens Island B	0.84	2.34	4.0	7.86
12-Mar-09	30.1	Torrens Island B	0.84	2.34	4.0	7.86
13-Mar-09	32.7	Torrens Island B	0.84	2.34	4.0	7.86
21-Mar-09	35.0	Torrens Island B	0.84	2.34	4.0	7.86
29-Mar-09	31.6	Pelican Point	0.52	2.34	4.0	4.87
30-Mar-09	32.0	Torrens Island B	0.84	2.34	4.0	7.86
31-Mar-09	33.1	Torrens Island B	0.84	2.34	4.0	7.86
					Total	429.90

4.3 Drummoyne Demand Management Program

4.3.1 Project Description

EnergyAustralia Network, operates one of the leading electricity networks in Australia, distributing electricity to the Sydney, Central Coast and Hunter regions of the State of New South Wales within a 22,275 square kilometre radius.

Drummoyne is a suburb in the inner west of Sydney, in New South Wales, located six kilometres west of the Sydney central business district. Drummoyne is mostly residential with some commercial developments, and still retains some of its industrial heritage.

EnergyAustralia's objective for the Drummoyne demand management project was to implement DSM measures that would maintain network performance at the required level at a lower cost than investing AUD4 million for an additional transformer at the Drummoyne zone substation which was approaching its design rating. Based on the load profiles for the substation, the key drivers for load growth appeared to be a mix of residential loads and a sizeable proportion of retail or commercial load. The area had experienced steady load growth in the years prior to 2005 that might be attributable to new residential development and multi-unit residential construction.

EnergyAustralia publicly sought proposals for DSM options capable of contributing to deferring the construction of the new transformer. EnergyAustralia also identified 20 major customers in the Drummoyne area, based on their peak demands, visited their sites and collected information about their usage of energy and possible DSM options. Using these various sources and information from experience in other areas, EnergyAustralia assembled a list of DSM options for analysis. Each of the options was assessed in relation to the likely size of demand reduction that would result at the time of network peak at the Drummoyne zone substation. The cost to EnergyAustralia of establishing and utilising each option at this level for varying periods of availability from one to three years was also estimated. Based on these estimates, EnergyAustralia ranked the options and compared them to the value of deferring the proposed investment.

A project to install compact fluorescent lamps (CFLs) in residential and small commercial premises was selected for implementation. Between October 2006 and May 2007, high power factor, 15 watt CFLs were packaged in boxes of five for distribution to households in the target area. Each household was given one box of five CFLs and these were installed free of charge. Door-to-door delivery and installation were carried out during specific times and days to maximise the number of people at home. For each box of CFLs delivered, delivery staff completed forms that included the householders' names, addresses and signatures plus answers to a short survey. The signed forms provided verification of the number of boxes of CFLs distributed. For households where no one was home, a flyer containing project information and a mail order form was left at the house. A follow-up phone survey was conducted during the delivery period to assess how many CFLs were actually installed.

The overall penetration rate for the installation of CFLs was about 26.1%. The project installed 81,347 CFLs in 5,865 properties and achieved an estimated 0.9 MVA reduction in winter evening peak demand (153 VA per household).

4.3.2 Example Calculation of Emissions Reduction

The example calculation was carried out for the 12 months between October 2008 and September 2009. We assumed that lighting was switched on for two hours a day (8.00 to 10.00 pm) from October to March ("summer") and for 3.5 hours a day (6.30 pm to 10.00 pm) from April to September ("winter"). We also assumed that the load reduction from the use of CFLs during these periods was 0.9 MVA (as reported by EnergyAustralia), which is 0.97 MVA including losses.

4.3.2.1 Average Grid Emissions Method

Shown below is an example calculation, using the Average Grid Emissions Method, of the total emissions reduction that would be achieved by the Drummoyne Demand Management Program during the summer of 2008/09, based on the assumptions outlined above.

Total energy saving achieved by the project (including losses): 1047.4 MWh

Average grid emissions factor for New South Wales: 0.90 tCO2-e/MWh

Emissions reduction achieved by the project: 942.6 tCO2-e

4.3.2.1 Modified Marginal Historical Emissions Method

Table 3 (page 31) presents an example calculation, using the Modified Marginal Historical Emissions Method, of the total emissions reduction that would be achieved by the Drummoyne Demand Management Program during the 12 month period, based on the assumptions outlined above. The table shows the marginal power plant between 8.00 pm and 10.00 pm on each day from October to March and between 6.30 pm and 10.00 pm on each day from April to September. Table 3 also shows the emissions factors of each of these power plants and the corresponding daily emissions reductions resulting from load reductions of 0.97 MVA (including losses) during the specified time periods.

The total emissions reduction that would be achieved from the Drummoyne program is shown at the bottom of the table.

Table 3. Example Calculation of Emissions Reduction Achieved by the Drummoyne Demand Management Program

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
1-Oct-08	Eraring	1.00	0.97	2.0	1.94
2-Oct-08	Tumut 1&2	0.00	0.97	2.0	0.00
3-Oct-08	Eraring	1.00	0.97	2.0	1.94
4-Oct-08	Eraring	1.00	0.97	2.0	1.94
5-Oct-08	Bayswater	0.99	0.97	2.0	1.92
6-Oct-08	Bayswater	0.99	0.97	2.0	1.92
7-Oct-08	Eraring	1.00	0.97	2.0	1.94
8-Oct-08	Bayswater	0.99	0.97	2.0	1.92
9-Oct-08	Eraring	1.00	0.97	2.0	1.94
10-Oct-08	Eraring	1.00	0.97	2.0	1.94
11-Oct-08	Bayswater	0.99	0.97	2.0	1.92
12-Oct-08	Liddell	1.08	0.97	2.0	2.10
13-Oct-08	Bayswater	0.99	0.97	2.0	1.92
14-Oct-08	Bayswater	0.99	0.97	2.0	1.92
15-Oct-08	Bayswater	0.99	0.97	2.0	1.92
16-Oct-08	Bayswater	0.99	0.97	2.0	1.92
17-Oct-08	Bayswater	0.99	0.97	2.0	1.92
18-Oct-08	Vales Point B	1.00	0.97	2.0	1.94
19-Oct-08	Bayswater	0.99	0.97	2.0	1.92
20-Oct-08	Bayswater	0.99	0.97	2.0	1.92
21-Oct-08	Bayswater	0.99	0.97	2.0	1.92
22-Oct-08	Bayswater	0.99	0.97	2.0	1.92
23-Oct-08	Tumut 1&2	0.00	0.97	2.0	0.00
24-Oct-08	Bayswater	0.99	0.97	2.0	1.92
25-Oct-08	Bayswater	0.99	0.97	2.0	1.92
26-Oct-08	Bayswater	0.99	0.97	2.0	1.92
27-Oct-08	Liddell	1.08	0.97	2.0	2.10
28-Oct-08	Tumut 1&2	0.00	0.97	2.0	0.00
29-Oct-08	Bayswater	0.99	0.97	2.0	1.92
30-Oct-08	Liddell	1.08	0.97	2.0	2.10
31-Oct-08	Tumut 1&2	0.00	0.97	2.0	0.00
1-Nov-08	Liddell	1.08	0.97	2.0	2.10
2-Nov-08	Liddell	1.08	0.97	2.0	2.10
3-Nov-08	Bayswater	0.99	0.97	2.0	1.92
4-Nov-08	Bayswater	0.99	0.97	2.0	1.92
5-Nov-08	Bayswater	0.99	0.97	2.0	1.92
6-Nov-08	Bayswater	0.99	0.97	2.0	1.92
7-Nov-08	Bayswater	0.99	0.97	2.0	1.92
8-Nov-08	Bayswater	0.99	0.97	2.0	1.92
9-Nov-08	Bayswater	0.99	0.97	2.0	1.92
10-Nov-08	Bayswater	0.99	0.97	2.0	1.92
11-Nov-08	Bayswater	0.99	0.97	2.0	1.92
12-Nov-08	Eraring	1.00	0.97	2.0	1.94

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
13-Nov-08	Eraring	1.00	0.97	2.0	1.94
14-Nov-08	Eraring	1.00	0.97	2.0	1.94
15-Nov-08	Bayswater	0.99	0.97	2.0	1.92
16-Nov-08	Bayswater	0.99	0.97	2.0	1.92
17-Nov-08	Bayswater	0.99	0.97	2.0	1.92
18-Nov-08	Eraring	1.00	0.97	2.0	1.94
19-Nov-08	Bayswater	0.99	0.97	2.0	1.92
20-Nov-08	Tallawarra	0.47	0.97	2.0	0.91
21-Nov-08	Bayswater	0.99	0.97	2.0	1.92
22-Nov-08	Bayswater	0.99	0.97	2.0	1.92
23-Nov-08	Bayswater	0.99	0.97	2.0	1.92
24-Nov-08	Bayswater	0.99	0.97	2.0	1.92
25-Nov-08	Bayswater	0.99	0.97	2.0	1.92
26-Nov-08	Bayswater	0.99	0.97	2.0	1.92
27-Nov-08	Bayswater	0.99	0.97	2.0	1.92
28-Nov-08	Bayswater	0.99	0.97	2.0	1.92
29-Nov-08	Bayswater	0.99	0.97	2.0	1.92
30-Nov-08	Bayswater	0.99	0.97	2.0	1.92
1-Dec-08	Bayswater	0.99	0.97	2.0	1.92
2-Dec-08	Bayswater	0.99	0.97	2.0	1.92
3-Dec-08	Bayswater	0.99	0.97	2.0	1.92
4-Dec-08	Bayswater	0.99	0.97	2.0	1.92
5-Dec-08	Eraring	1.00	0.97	2.0	1.94
6-Dec-08	Bayswater	0.99	0.97	2.0	1.92
7-Dec-08	Bayswater	0.99	0.97	2.0	1.92
8-Dec-08	Bayswater	0.99	0.97	2.0	1.92
9-Dec-08	Bayswater	0.99	0.97	2.0	1.92
10-Dec-08	Bayswater	0.99	0.97	2.0	1.92
11-Dec-08	Bayswater	0.99	0.97	2.0	1.92
12-Dec-08	Mt Piper	0.94	0.97	2.0	1.82
13-Dec-08	Mt Piper	0.94	0.97	2.0	1.82
14-Dec-08	Mt Piper	0.94	0.97	2.0	1.82
15-Dec-08	Bayswater	0.99	0.97	2.0	1.92
16-Dec-08	Bayswater	0.99	0.97	2.0	1.92
17-Dec-08	Bayswater	0.99	0.97	2.0	1.92
18-Dec-08	Bayswater	0.99	0.97	2.0	1.92
19-Dec-08	Bayswater	0.99	0.97	2.0	1.92
20-Dec-08	Eraring	1.00	0.97	2.0	1.94
21-Dec-08	Vales Point B	1.00	0.97	2.0	1.94
22-Dec-08	Bayswater	0.99	0.97	2.0	1.92
23-Dec-08	Bayswater	0.99	0.97	2.0	1.92
24-Dec-08	Bayswater	0.99	0.97	2.0	1.92
25-Dec-08	Eraring	1.00	0.97	2.0	1.94
26-Dec-08	Bayswater	0.99	0.97	2.0	1.92
27-Dec-08	Bayswater	0.99	0.97	2.0	1.92
28-Dec-08	Bayswater	0.99	0.97	2.0	1.92
29-Dec-08	Bayswater	0.99	0.97	2.0	1.92
30-Dec-08	Bayswater	0.99	0.97	2.0	1.92
31-Dec-08	Mt Piper	0.94	0.97	2.0	1.82

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
1-Jan-09	Bayswater	0.99	0.97	2.0	1.92
2-Jan-09	Bayswater	0.99	0.97	2.0	1.92
3-Jan-09	Bayswater	0.99	0.97	2.0	1.92
4-Jan-09	Bayswater	0.99	0.97	2.0	1.92
5-Jan-09	Eraring	1.00	0.97	2.0	1.94
6-Jan-09	Eraring	1.00	0.97	2.0	1.94
7-Jan-09	Eraring	1.00	0.97	2.0	1.94
8-Jan-09	Bayswater	0.99	0.97	2.0	1.92
9-Jan-09	Liddell	1.08	0.97	2.0	2.10
10-Jan-09	Bayswater	0.99	0.97	2.0	1.92
11-Jan-09	Bayswater	0.99	0.97	2.0	1.92
12-Jan-09	Bayswater	0.99	0.97	2.0	1.92
13-Jan-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
14-Jan-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
15-Jan-09	Bayswater	0.99	0.97	2.0	1.92
16-Jan-09	Bayswater	0.99	0.97	2.0	1.92
17-Jan-09	Bayswater	0.99	0.97	2.0	1.92
18-Jan-09	Bayswater	0.99	0.97	2.0	1.92
19-Jan-09	Eraring	1.00	0.97	2.0	1.94
20-Jan-09	Bayswater	0.99	0.97	2.0	1.92
21-Jan-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
22-Jan-09	Bayswater	0.99	0.97	2.0	1.92
23-Jan-09	Liddell	1.08	0.97	2.0	2.10
24-Jan-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
25-Jan-09	Eraring	1.00	0.97	2.0	1.94
26-Jan-09	Tallawarra	0.47	0.97	2.0	0.91
27-Jan-09	Bayswater	0.99	0.97	2.0	1.92
28-Jan-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
29-Jan-09	Tumut 3	0.00	0.97	2.0	0.00
30-Jan-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
31-Jan-09	Eraring	1.00	0.97	2.0	1.94
1-Feb-09	Bayswater	0.99	0.97	2.0	1.92
2-Feb-09	Bayswater	0.99	0.97	2.0	1.92
3-Feb-09	Bayswater	0.99	0.97	2.0	1.92
4-Feb-09	Bayswater	0.99	0.97	2.0	1.92
5-Feb-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
6-Feb-09	Tumut 3	0.00	0.97	2.0	0.00
7-Feb-09	Tumut 3	0.00	0.97	2.0	0.00
8-Feb-09	Tumut 1 & 2	0.00	0.97	2.0	0.00
9-Feb-09	Bayswater	0.99	0.97	2.0	1.92
10-Feb-09	Bayswater	0.99	0.97	2.0	1.92
11-Feb-09	Eraring	1.00	0.97	2.0	1.94
12-Feb-09	Bayswater	0.99	0.97	2.0	1.92
13-Feb-09	Bayswater	0.99	0.97	2.0	1.92
14-Feb-09	Bayswater	0.99	0.97	2.0	1.92
15-Feb-09	Bayswater	0.99	0.97	2.0	1.92
16-Feb-09	Bayswater	0.99	0.97	2.0	1.92
17-Feb-09	Bayswater	0.99	0.97	2.0	1.92
18-Feb-09	Bayswater	0.99	0.97	2.0	1.92

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
19-Feb-09	Bayswater	0.99	0.97	2.0	1.92
20-Feb-09	Bayswater	0.99	0.97	2.0	1.92
21-Feb-09	Bayswater	0.99	0.97	2.0	1.92
22-Feb-09	Bayswater	0.99	0.97	2.0	1.92
23-Feb-09	Bayswater	0.99	0.97	2.0	1.92
24-Feb-09	Bayswater	0.99	0.97	2.0	1.92
25-Feb-09	Bayswater	0.99	0.97	2.0	1.92
26-Feb-09	Tallawarra	0.47	0.97	2.0	0.91
27-Feb-09	Bayswater	0.99	0.97	2.0	1.92
28-Feb-09	Mt Piper	0.94	0.97	2.0	1.82
1-Mar-09	Bayswater	0.99	0.97	2.0	1.92
2-Mar-09	Bayswater	0.99	0.97	2.0	1.92
3-Mar-09	Bayswater	0.99	0.97	2.0	1.92
4-Mar-09	Bayswater	0.99	0.97	2.0	1.92
5-Mar-09	Bayswater	0.99	0.97	2.0	1.92
6-Mar-09	Bayswater	0.99	0.97	2.0	1.92
7-Mar-09	Bayswater	0.99	0.97	2.0	1.92
8-Mar-09	Mt Piper	0.94	0.97	2.0	1.82
9-Mar-09	Bayswater	0.99	0.97	2.0	1.92
10-Mar-09	Bayswater	0.99	0.97	2.0	1.92
11-Mar-09	Bayswater	0.99	0.97	2.0	1.92
12-Mar-09	Bayswater	0.99	0.97	2.0	1.92
13-Mar-09	Bayswater	0.99	0.97	2.0	1.92
14-Mar-09	Bayswater	0.99	0.97	2.0	1.92
15-Mar-09	Bayswater	0.99	0.97	2.0	1.92
16-Mar-09	Bayswater	0.99	0.97	2.0	1.92
17-Mar-09	Bayswater	0.99	0.97	2.0	1.92
18-Mar-09	Bayswater	0.99	0.97	2.0	1.92
19-Mar-09	Bayswater	0.99	0.97	2.0	1.92
20-Mar-09	Bayswater	0.99	0.97	2.0	1.92
21-Mar-09	Bayswater	0.99	0.97	2.0	1.92
22-Mar-09	Bayswater	0.99	0.97	2.0	1.92
23-Mar-09	Bayswater	0.99	0.97	2.0	1.92
24-Mar-09	Bayswater	0.99	0.97	2.0	1.92
25-Mar-09	Bayswater	0.99	0.97	2.0	1.92
26-Mar-09	Bayswater	0.99	0.97	2.0	1.92
27-Mar-09	Bayswater	0.99	0.97	2.0	1.92
28-Mar-09	Bayswater	0.99	0.97	2.0	1.92
29-Mar-09	Bayswater	0.99	0.97	2.0	1.92
30-Mar-09	Bayswater	0.99	0.97	2.0	1.92
31-Mar-09	Bayswater	0.99	0.97	2.0	1.92
1-Apr-09	Bayswater	0.99	0.97	3.5	3.36
2-Apr-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
3-Apr-09	Bayswater	0.99	0.97	3.5	3.36
4-Apr-09	Bayswater	0.99	0.97	3.5	3.36
5-Apr-09	Bayswater	0.99	0.97	3.5	3.36
6-Apr-09	Bayswater	0.99	0.97	3.5	3.36
7-Apr-09	Eraring	1.00	0.97	3.5	3.40
8-Apr-09	Bayswater	0.99	0.97	3.5	3.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
9-Apr-09	Bayswater	0.99	0.97	3.5	3.36
10-Apr-09	Bayswater	0.99	0.97	3.5	3.36
11-Apr-09	Bayswater	0.99	0.97	3.5	3.36
12-Apr-09	Bayswater	0.99	0.97	3.5	3.36
13-Apr-09	Bayswater	0.99	0.97	3.5	3.36
14-Apr-09	Mt Piper	0.94	0.97	3.5	3.19
15-Apr-09	Tallawarra	0.47	0.97	3.5	1.60
16-Apr-09	Tallawarra	0.47	0.97	3.5	1.60
17-Apr-09	Uranquinty	0.74	0.97	3.5	2.51
18-Apr-09	Tallawarra	0.47	0.97	3.5	1.60
19-Apr-09	Tallawarra	0.47	0.97	3.5	1.60
20-Apr-09	Uranquinty	0.74	0.97	3.5	2.51
21-Apr-09	Uranquinty	0.74	0.97	3.5	2.51
22-Apr-09	Mt Piper	0.94	0.97	3.5	3.19
23-Apr-09	Bayswater	0.99	0.97	3.5	3.36
24-Apr-09	Bayswater	0.99	0.97	3.5	3.36
25-Apr-09	Bayswater	0.99	0.97	3.5	3.36
26-Apr-09	Eraring	1.00	0.97	3.5	3.40
27-Apr-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
28-Apr-09	Uranquinty	0.74	0.97	3.5	2.51
29-Apr-09	Uranquinty	0.74	0.97	3.5	2.51
30-Apr-09	Uranquinty	0.74	0.97	3.5	2.51
1-May-09	Tallawarra	0.47	0.97	3.5	1.60
2-May-09	Tallawarra	0.47	0.97	3.5	1.60
3-May-09	Tallawarra	0.47	0.97	3.5	1.60
4-May-09	Tallawarra	0.47	0.97	3.5	1.60
5-May-09	Uranquinty	0.74	0.97	3.5	2.51
6-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
7-May-09	Eraring	1.00	0.97	3.5	3.40
8-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
9-May-09	Eraring	1.00	0.97	3.5	3.40
10-May-09	Tallawarra	0.47	0.97	3.5	1.60
11-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
12-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
13-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
14-May-09	Tallawarra	0.47	0.97	3.5	1.60
15-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
16-May-09	Liddell	1.08	0.97	3.5	3.67
17-May-09	Liddell	1.08	0.97	3.5	3.67
18-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
19-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
20-May-09	Tallawarra	0.47	0.97	3.5	1.60
21-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
22-May-09	Liddell	1.08	0.97	3.5	3.67
23-May-09	Vales Point B	1.00	0.97	3.5	3.40
24-May-09	Bayswater	0.99	0.97	3.5	3.36
25-May-09	Tallawarra	0.47	0.97	3.5	1.60
26-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
27-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
28-May-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
29-May-09	Uranquinty	0.74	0.97	3.5	2.51

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
30-May-09	Liddell	1.08	0.97	3.5	3.67
31-May-09	Tallawarra	0.47	0.97	3.5	1.60
1-Jun-09	Uranquinty	0.74	0.97	3.5	2.51
2-Jun-09	Uranquinty	0.74	0.97	3.5	2.51
3-Jun-09	Uranquinty	0.74	0.97	3.5	2.51
4-Jun-09	Uranquinty	0.74	0.97	3.5	2.51
5-Jun-09	Liddell	1.08	0.97	3.5	3.67
6-Jun-09	Bayswater	0.99	0.97	3.5	3.36
7-Jun-09	Bayswater	0.99	0.97	3.5	3.36
8-Jun-09	Mt Piper	0.94	0.97	3.5	3.19
9-Jun-09	Tumut 3	0.00	0.97	3.5	0.00
10-Jun-09	Tumut 3	0.00	0.97	3.5	0.00
11-Jun-09	Tumut 3	0.00	0.97	3.5	0.00
12-Jun-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
13-Jun-09	Bayswater	0.99	0.97	3.5	3.36
14-Jun-09	Uranquinty	0.74	0.97	3.5	2.51
15-Jun-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
16-Jun-09	Bayswater	0.99	0.97	3.5	3.36
17-Jun-09	Bayswater	0.99	0.97	3.5	3.36
18-Jun-09	Uranquinty	0.74	0.97	3.5	2.51
19-Jun-09	Bayswater	0.99	0.97	3.5	3.36
20-Jun-09	Bayswater	0.99	0.97	3.5	3.36
21-Jun-09	Bayswater	0.99	0.97	3.5	3.36
22-Jun-09	Bayswater	0.99	0.97	3.5	3.36
23-Jun-09	Bayswater	0.99	0.97	3.5	3.36
24-Jun-09	Bayswater	0.99	0.97	3.5	3.36
25-Jun-09	Bayswater	0.99	0.97	3.5	3.36
26-Jun-09	Liddell	1.08	0.97	3.5	3.67
27-Jun-09	Liddell	1.08	0.97	3.5	3.67
28-Jun-09	Bayswater	0.99	0.97	3.5	3.36
29-Jun-09	Bayswater	0.99	0.97	3.5	3.36
30-Jun-09	Bayswater	0.99	0.97	3.5	3.36
1-Jul-09	Bayswater	0.99	0.97	3.5	3.36
2-Jul-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
3-Jul-09	Tumut 3	0.00	0.97	3.5	0.00
4-Jul-09	Eraring	1.00	0.97	3.5	3.40
5-Jul-09	Eraring	1.00	0.97	3.5	3.40
6-Jul-09	Eraring	1.00	0.97	3.5	3.40
7-Jul-09	Eraring	1.00	0.97	3.5	3.40
8-Jul-09	Eraring	1.00	0.97	3.5	3.40
9-Jul-09	Eraring	1.00	0.97	3.5	3.40
10-Jul-09	Eraring	1.00	0.97	3.5	3.40
11-Jul-09	Eraring	1.00	0.97	3.5	3.40
12-Jul-09	Eraring	1.00	0.97	3.5	3.40
13-Jul-09	Eraring	1.00	0.97	3.5	3.40
14-Jul-09	Eraring	1.00	0.97	3.5	3.40
15-Jul-09	Eraring	1.00	0.97	3.5	3.40
16-Jul-09	Eraring	1.00	0.97	3.5	3.40
17-Jul-09	Eraring	1.00	0.97	3.5	3.40
18-Jul-09	Eraring	1.00	0.97	3.5	3.40

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
19-Jul-09	Eraring	1.00	0.97	3.5	3.40
20-Jul-09	Eraring	1.00	0.97	3.5	3.40
21-Jul-09	Eraring	1.00	0.97	3.5	3.40
22-Jul-09	Eraring	1.00	0.97	3.5	3.40
23-Jul-09	Eraring	1.00	0.97	3.5	3.40
24-Jul-09	Eraring	1.00	0.97	3.5	3.40
25-Jul-09	Eraring	1.00	0.97	3.5	3.40
26-Jul-09	Eraring	1.00	0.97	3.5	3.40
27-Jul-09	Uranquinty	0.74	0.97	3.5	2.51
28-Jul-09	Tumut 3	0.00	0.97	3.5	0.00
29-Jul-09	Tumut 3	0.00	0.97	3.5	0.00
30-Jul-09	Tumut 3	0.00	0.97	3.5	0.00
31-Jul-09	Tumut 3	0.00	0.97	3.5	0.00
1-Aug-09	Bayswater	0.99	0.97	3.5	3.36
2-Aug-09	Liddell	1.08	0.97	3.5	3.67
3-Aug-09	Eraring	1.00	0.97	3.5	3.40
4-Aug-09	Uranquinty	0.74	0.97	3.5	2.51
5-Aug-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
6-Aug-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
7-Aug-09	Colongra	0.74	0.97	3.5	2.51
8-Aug-09	Liddell	1.08	0.97	3.5	3.67
9-Aug-09	Liddell	1.08	0.97	3.5	3.67
10-Aug-09	Mt Piper	0.94	0.97	3.5	3.19
11-Aug-09	Uranquinty	0.74	0.97	3.5	2.51
12-Aug-09	Bayswater	0.99	0.97	3.5	3.36
13-Aug-09	Bayswater	0.99	0.97	3.5	3.36
14-Aug-09	Bayswater	0.99	0.97	3.5	3.36
15-Aug-09	Bayswater	0.99	0.97	3.5	3.36
16-Aug-09	Bayswater	0.99	0.97	3.5	3.36
17-Aug-09	Liddell	1.08	0.97	3.5	3.67
18-Aug-09	Liddell	1.08	0.97	3.5	3.67
19-Aug-09	Bayswater	0.99	0.97	3.5	3.36
20-Aug-09	Bayswater	0.99	0.97	3.5	3.36
21-Aug-09	Bayswater	0.99	0.97	3.5	3.36
22-Aug-09	Liddell	1.08	0.97	3.5	3.67
23-Aug-09	Bayswater	0.99	0.97	3.5	3.36
24-Aug-09	Bayswater	0.99	0.97	3.5	3.36
25-Aug-09	Uranquinty	0.74	0.97	3.5	2.51
26-Aug-09	Bayswater	0.99	0.97	3.5	3.36
27-Aug-09	Bayswater	0.99	0.97	3.5	3.36
28-Aug-09	Mt Piper	0.94	0.97	3.5	3.19
29-Aug-09	Liddell	1.08	0.97	3.5	3.67
30-Aug-09	Liddell	1.08	0.97	3.5	3.67
31-Aug-09	Bayswater	0.99	0.97	3.5	3.36
1-Sep-09	Tallawarra	0.47	0.97	3.5	1.60
2-Sep-09	Tumut 1 & 2	0.00	0.97	3.5	0.00
3-Sep-09	Liddell	1.08	0.97	3.5	3.67
4-Sep-09	Uranquinty	0.74	0.97	3.5	2.51
5-Sep-09	Tallawarra	0.47	0.97	3.5	1.60
6-Sep-09	Bayswater	0.99	0.97	3.5	3.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
7-Sep-09	Tallawarra	0.47	0.97	3.5	1.60
8-Sep-09	Eraring	1.00	0.97	3.5	3.40
9-Sep-09	Tumut 3	0.00	0.97	3.5	0.00
10-Sep-09	Bayswater	0.99	0.97	3.5	3.36
11-Sep-09	Bayswater	0.99	0.97	3.5	3.36
12-Sep-09	Bayswater	0.99	0.97	3.5	3.36
13-Sep-09	Bayswater	0.99	0.97	3.5	3.36
14-Sep-09	Tallawarra	0.47	0.97	3.5	1.60
15-Sep-09	Tallawarra	0.47	0.97	3.5	1.60
16-Sep-09	Bayswater	0.99	0.97	3.5	3.36
17-Sep-09	Uranquinty	0.74	0.97	3.5	2.51
18-Sep-09	Bayswater	0.99	0.97	3.5	3.36
19-Sep-09	Tallawarra	0.47	0.97	3.5	1.60
20-Sep-09	Bayswater	0.99	0.97	3.5	3.36
21-Sep-09	Bayswater	0.99	0.97	3.5	3.36
22-Sep-09	Bayswater	0.99	0.97	3.5	3.36
23-Sep-09	Bayswater	0.99	0.97	3.5	3.36
24-Sep-09	Bayswater	0.99	0.97	3.5	3.36
25-Sep-09	Liddell	1.08	0.97	3.5	3.67
26-Sep-09	Bayswater	0.99	0.97	3.5	3.36
27-Sep-09	Bayswater	0.99	0.97	3.5	3.36
28-Sep-09	Uranquinty	0.74	0.97	3.5	2.51
29-Sep-09	Tumut 3	0.00	0.97	3.5	0.00
30-Sep-09	Bayswater	0.99	0.97	3.5	3.36
				Total	786.17

4.4 Binda-Bigga Demand Management Project

4.4.1 Project Description

The electricity distributor, Country Energy Network manages Australia's largest energy supply network in regional and rural areas across 95 per cent of the State of New South Wales, serving around 870,000 customers.

Binda and Bigga are two small rural settlements near Crookwell about 230 km south-west of Sydney. The Binda-Bigga area has about 250 electricity customers, mostly residential.

As peak electricity use increased in the area, the electricity line that runs from Crookwell through Binda and Bigga and then on to Grabine was reaching its maximum capacity. Fault levels and voltage levels were a concern along the line, especially during storm events, due to the length of the line and the rugged country through which the line passes. Many customers in Binda and Bigga were experiencing unacceptable voltage fluctuations which could be resolved only by extensive reconductoring of the line.

In 2004, Country Energy contracted the Sustainable Energy Development Authority (SEDA) to relieve the electrical demand on the Crookwell to Grabine feeder during times of winter evening peaks. The aim of the contract was to defer the need for the upgrade of the feeder by reducing electricity demand during the winter evening peak periods (the four hours from 6 pm to 10 pm).

SEDA developed an Energy Saver Package as the primary mechanism to achieve the required load reduction of 200kVA. To reduce the demand on the electricity feeder during the peak time, the Package was structured around appliances that would reduce electricity demand from residents cooking an evening meal and heating their homes. The Package enabled residents to affordably switch from electric to gas appliances. It offered residents:

- discounted gas room heaters and cooking stoves (a maximum of two appliances per household);
- free installation of gas appliances and gas bottles, and removal of electrical appliances for metal recycling; and
- gas credits of AUD 170 per appliance – equivalent to free gas for a year.

Overall 70 customers purchased an Energy Saver Package, purchasing 106 appliances in total, between July and October 2004. This exceeded the target of 98 appliances and included:

- 60 unflued room heaters (56%);
- 42 cooking stoves (40%); and
- 4 flued room heaters (4%).

Country Energy estimated that the average electricity usage per household in the Binda-Bigga area was 4 kWh per day for room heating and 3 kWh per day for cooking.

4.4.2 Example Calculation of Emissions Reduction

The example calculation was carried out for the 12 months between October 2008 and September 2009. We assumed that the 30 households who switched from electrical to gas cookers spent 30 minutes every day cooking their evening meal between 6.30 and 7.00 pm. The total electricity use for cooking by these households was 90 kWh per day, or 101 kWh including losses. We also assumed that the 47 households who switched from electrical to gas room heaters used room heating for two hours between 8.00 pm and 10.00 pm during September to March (“summer”) and for four hours between 6.00 pm and 10.00 pm during April to September (“winter”). Heating was required in summer because the Binda-Bigga area is at an elevation of about 650 metres in Australia’s Great Dividing Range. Minimum temperatures at night are quite low, seldom exceeding 18ºC even in the middle of summer.

We further assumed that the electricity usage by these households for room heating was 2 kWh per household per day in “summer” (a total of 94 kWh per day, or 101 kWh including losses) and 4 kWh per household per day in “winter” (a total of 188 kWh per day, or 202 kWh including losses).

The emissions reduction achieved by this fuel substitution DSM project was estimated by first calculating the total emissions that would be released by the households using electrical appliances for cooking and room heating. Then the total emissions released by the same households using gas appliances for cooking and room heating were calculated. The total emissions reduction achieved by the project was then the difference between these two figures.

4.4.2.1 Average Grid Emissions Method

Shown below is an example calculation, using the Average Grid Emissions Method, of the total emissions that would be released by the households by using electrical appliances for cooking and room heating.

Cooking

Total energy consumption for cooking (including losses): 39.6 MWh

Average grid emissions factor for New South Wales: 0.90 tCO2-e/MWh

Emissions released by cooking: 35.6 tCO2-e

Room Heating

Total energy consumption for room heating (including losses): 59.5 MWh

Average grid emissions factor for New South Wales: 0.90 tCO2-e/MWh

Emissions released by room heating: 53.5 tCO2-e

Total emissions released from using electrical appliances: 89.1 tCO2-e

Table 4 presents an example calculation of the total emissions that would be released by the households using gas cookers and gas room heaters. The calculation assumes that the same quantity of energy is used by the gas appliances as the electrical appliances[53]: for cooking 90kWh per day of electricity = 0.324 GJ of gas; for room heating 94 kWh of electricity in "summer" = 0.3384 GJ of gas and 188 kWh of electricity in "winter" = 0.6768 GJ of gas). The emissions factor for LPG (bottled gas) used in Table 5 was obtained from a handbook of emissions factors published by the Australian (federal) Government[54].

Table 4. Example Calculation of Emissions Released from Cooking and Room Heating with Gas Appliances in the Binda-Bigga Demand Management Project

Activity	Daily LPG Use (GJ)	No Days	Emissions Factor (tCO_2-e/GJ)	Emissions Released (tCO2-e)
Cooking	0.324	365	0.0599	7.1
Room heating ("summer")	0.3384	182	0.0599	3.7
Room heating ("winter')	0.6768	183	0.0599	7.4
			Total	18.2

Therefore, the emissions reduction achieved by the Binda-Bigga Demand Management Project:

$$89.1 - 18.2 = 70.9 \text{ } tCO_2\text{-e}$$

[53] This assumption was made to simplify the calculation. However, it is unlikely to be accurate, given the different conversion efficiencies of electrical and gas appliances.

[54] Department of Climate Change (2010). Op. cit.

4.4.2.1 Modified Marginal Historical Emissions Method

Table 5 presents an example calculation, using the Modified Marginal Historical Emissions Method, of the total emissions that would be released by the households by cooking with electrical appliances. The table shows the marginal power plant between 6.30 pm and 7.00 pm on each day during the 12 month period. Table 4 also shows the emissions factors of each of these power plants and the corresponding daily emissions resulting from the 101 kWh (including losses) of electricity used during the specified time period.

Table 5. Example Calculation of Emissions Released from Cooking with Electrical Appliances in the Binda-Bigga Demand Management Project

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
1-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
2-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
3-Oct-08	Vales Point B	1.00	0.101	0.10
4-Oct-08	Eraring	1.00	0.101	0.10
5-Oct-08	Bayswater	0.99	0.101	0.10
6-Oct-08	Liddell	1.08	0.101	0.11
7-Oct-08	Eraring	1.00	0.101	0.10
8-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
9-Oct-08	Eraring	1.00	0.101	0.10
10-Oct-08	Vales Point B	1.00	0.101	0.10
11-Oct-08	Bayswater	0.99	0.101	0.10
12-Oct-08	Eraring	1.00	0.101	0.10
13-Oct-08	Vales Point B	1.00	0.101	0.10
14-Oct-08	Mt Piper	0.94	0.101	0.09
15-Oct-08	Vales Point B	1.00	0.101	0.10
16-Oct-08	Wallerawang C	1.05	0.101	0.11
17-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
18-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
19-Oct-08	Vales Point B	1.00	0.101	0.10
20-Oct-08	Tumut 3	0.00	0.101	0.00
21-Oct-08	Mt Piper	0.94	0.101	0.09
22-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
23-Oct-08	Liddell	1.08	0.101	0.11
24-Oct-08	Tumut 3	0.00	0.101	0.00
25-Oct-08	Bayswater	0.99	0.101	0.10
26-Oct-08	Vales Point B	1.00	0.101	0.10
27-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
28-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
29-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
30-Oct-08	Tumut 1 & 2	0.00	0.101	0.00
31-Oct-08	Shoalhaven	0.00	0.101	0.00
1-Nov-08	Mt Piper	0.94	0.101	0.09
2-Nov-08	Tumut 1 & 2	0.00	0.101	0.00
3-Nov-08	Tumut 1 & 2	0.00	0.101	0.00
4-Nov-08	Liddell	1.08	0.101	0.11

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
5-Nov-08	Vales Point B	1.00	0.101	0.10
6-Nov-08	Tumut 1 & 2	0.00	0.101	0.00
7-Nov-08	Bayswater	0.99	0.101	0.10
8-Nov-08	Tallawarra	0.47	0.101	0.05
9-Nov-08	Vales Point B	1.00	0.101	0.10
10-Nov-08	Tumut 3	0.00	0.101	0.00
11-Nov-08	Bayswater	0.99	0.101	0.10
12-Nov-08	Bayswater	0.99	0.101	0.10
13-Nov-08	Bayswater	0.99	0.101	0.10
14-Nov-08	Bayswater	0.99	0.101	0.10
15-Nov-08	Bayswater	0.99	0.101	0.10
16-Nov-08	Eraring	1.00	0.101	0.10
17-Nov-08	Liddell	1.08	0.101	0.11
18-Nov-08	Eraring	1.00	0.101	0.10
19-Nov-08	Tallawarra	0.47	0.101	0.05
20-Nov-08	Tallawarra	0.47	0.101	0.05
21-Nov-08	Bayswater	0.99	0.101	0.10
22-Nov-08	Uranquinty	0.74	0.101	0.07
23-Nov-08	Eraring	1.00	0.101	0.10
24-Nov-08	Bayswater	0.99	0.101	0.10
25-Nov-08	Bayswater	0.99	0.101	0.10
26-Nov-08	Eraring	1.00	0.101	0.10
27-Nov-08	Mt Piper	0.94	0.101	0.09
28-Nov-08	Liddell	1.08	0.101	0.11
29-Nov-08	Bayswater	0.99	0.101	0.10
30-Nov-08	Bayswater	0.99	0.101	0.10
1-Dec-08	Tumut 3	0.00	0.101	0.00
2-Dec-08	Tumut 3	0.00	0.101	0.00
3-Dec-08	Bayswater	0.99	0.101	0.10
4-Dec-08	Liddell	1.08	0.101	0.11
5-Dec-08	Tumut 3	0.00	0.101	0.00
6-Dec-08	Bayswater	0.99	0.101	0.10
7-Dec-08	Bayswater	0.99	0.101	0.10
8-Dec-08	Bayswater	0.99	0.101	0.10
9-Dec-08	Bayswater	0.99	0.101	0.10
10-Dec-08	Bayswater	0.99	0.101	0.10
11-Dec-08	Tumut 3	0.00	0.101	0.00
12-Dec-08	Bayswater	0.99	0.101	0.10
13-Dec-08	Bayswater	0.99	0.101	0.10
14-Dec-08	Bayswater	0.99	0.101	0.10
15-Dec-08	Tumut 3	0.00	0.101	0.00
16-Dec-08	Bayswater	0.99	0.101	0.10
17-Dec-08	Eraring	1.00	0.101	0.10
18-Dec-08	Eraring	1.00	0.101	0.10
19-Dec-08	Bayswater	0.99	0.101	0.10
20-Dec-08	Tallawarra	0.47	0.101	0.05
21-Dec-08	Liddell	1.08	0.101	0.11
22-Dec-08	Bayswater	0.99	0.101	0.10
23-Dec-08	Tumut 3	0.00	0.101	0.00

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
24-Dec-08	Bayswater	0.99	0.101	0.10
25-Dec-08	Wallerawang C	1.05	0.101	0.11
26-Dec-08	Bayswater	0.99	0.101	0.10
27-Dec-08	Bayswater	0.99	0.101	0.10
28-Dec-08	Eraring	1.00	0.101	0.10
29-Dec-08	Bayswater	0.99	0.101	0.10
30-Dec-08	Bayswater	0.99	0.101	0.10
31-Dec-08	Bayswater	0.99	0.101	0.10
1-Jan-09	Eraring	1.00	0.101	0.10
2-Jan-09	Bayswater	0.99	0.101	0.10
3-Jan-09	Bayswater	0.99	0.101	0.10
4-Jan-09	Bayswater	0.99	0.101	0.10
5-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
6-Jan-09	Uranquinty	0.74	0.101	0.07
7-Jan-09	Eraring	1.00	0.101	0.10
8-Jan-09	Eraring	1.00	0.101	0.10
9-Jan-09	Bayswater	0.99	0.101	0.10
10-Jan-09	Bayswater	0.99	0.101	0.10
11-Jan-09	Vales Point B	1.00	0.101	0.10
12-Jan-09	Eraring	1.00	0.101	0.10
13-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
14-Jan-09	Uranquinty	0.74	0.101	0.07
15-Jan-09	Eraring	1.00	0.101	0.10
16-Jan-09	Eraring	1.00	0.101	0.10
17-Jan-09	Bayswater	0.99	0.101	0.10
18-Jan-09	Eraring	1.00	0.101	0.10
19-Jan-09	Bayswater	0.99	0.101	0.10
20-Jan-09	Bayswater	0.99	0.101	0.10
21-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
22-Jan-09	Bayswater	0.99	0.101	0.10
23-Jan-09	Bayswater	0.99	0.101	0.10
24-Jan-09	Bayswater	0.99	0.101	0.10
25-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
26-Jan-09	Bayswater	0.99	0.101	0.10
27-Jan-09	Bayswater	0.99	0.101	0.10
28-Jan-09	Tumut 3	0.00	0.101	0.00
29-Jan-09	Tumut 3	0.00	0.101	0.00
30-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
31-Jan-09	Uranquinty	0.74	0.101	0.07
1-Feb-09	Tallawarra	0.47	0.101	0.05
2-Feb-09	Tumut 1 & 2	0.00	0.101	0.00
3-Feb-09	Uranquinty	0.74	0.101	0.07
4-Feb-09	Uranquinty	0.74	0.101	0.07
5-Feb-09	Tumut 1 & 2	0.00	0.101	0.00
6-Feb-09	Uranquinty	0.74	0.101	0.07
7-Feb-09	Eraring	1.00	0.101	0.10
8-Feb-09	Uranquinty	0.74	0.101	0.07
9-Feb-09	Bayswater	0.99	0.101	0.10
10-Feb-09	Tallawarra	0.47	0.101	0.05

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
11-Feb-09	Wallerawang C	1.05	0.101	0.11
12-Feb-09	Liddell	1.08	0.101	0.11
13-Feb-09	Bayswater	0.99	0.101	0.10
14-Feb-09	Bayswater	0.99	0.101	0.10
15-Feb-09	Bayswater	0.99	0.101	0.10
16-Feb-09	Eraring	1.00	0.101	0.10
17-Feb-09	Bayswater	0.99	0.101	0.10
18-Feb-09	Bayswater	0.99	0.101	0.10
19-Feb-09	Bayswater	0.99	0.101	0.10
20-Feb-09	Tallawarra	0.47	0.101	0.05
21-Feb-09	Bayswater	0.99	0.101	0.10
22-Feb-09	Mt Piper	0.94	0.101	0.09
23-Feb-09	Tumut 1 & 2	0.00	0.101	0.00
24-Feb-09	Tumut 1 & 2	0.00	0.101	0.00
25-Feb-09	Tallawarra	0.47	0.101	0.05
26-Feb-09	Bayswater	0.99	0.101	0.10
27-Feb-09	Tallawarra	0.47	0.101	0.05
28-Feb-09	Bayswater	0.99	0.101	0.10
1-Mar-09	Eraring	1.00	0.101	0.10
2-Mar-09	Eraring	1.00	0.101	0.10
3-Mar-09	Tallawarra	0.47	0.101	0.05
4-Mar-09	Bayswater	0.99	0.101	0.10
5-Mar-09	Liddell	1.08	0.101	0.11
6-Mar-09	Bayswater	0.99	0.101	0.10
7-Mar-09	Bayswater	0.99	0.101	0.10
8-Mar-09	Bayswater	0.99	0.101	0.10
9-Mar-09	Bayswater	0.99	0.101	0.10
10-Mar-09	Bayswater	0.99	0.101	0.10
11-Mar-09	Bayswater	0.99	0.101	0.10
12-Mar-09	Vales Point B	1.00	0.101	0.10
13-Mar-09	Vales Point B	1.00	0.101	0.10
14-Mar-09	Bayswater	0.99	0.101	0.10
15-Mar-09	Bayswater	0.99	0.101	0.10
16-Mar-09	Tumut 1 & 2	0.00	0.101	0.00
17-Mar-09	Eraring	1.00	0.101	0.10
18-Mar-09	Bayswater	0.99	0.101	0.10
19-Mar-09	Bayswater	0.99	0.101	0.10
20-Mar-09	Eraring	1.00	0.101	0.10
21-Mar-09	Bayswater	0.99	0.101	0.10
22-Mar-09	Vales Point B	1.00	0.101	0.10
23-Mar-09	Bayswater	0.99	0.101	0.10
24-Mar-09	Eraring	1.00	0.101	0.10
25-Mar-09	Mt Piper	0.94	0.101	0.09
26-Mar-09	Tallawarra	0.47	0.101	0.05
27-Mar-09	Bayswater	0.99	0.101	0.10
28-Mar-09	Bayswater	0.99	0.101	0.10
29-Mar-09	Wallerawang C	1.05	0.101	0.11
30-Mar-09	Liddell	1.08	0.101	0.11
31-Mar-09	Eraring	1.00	0.101	0.10

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
1-Apr-09	Liddell	1.08	0.101	0.11
2-Apr-09	Tumut 1 & 2	0.00	0.101	0.00
3-Apr-09	Wallerawang C	1.05	0.101	0.11
4-Apr-09	Wallerawang C	1.05	0.101	0.11
5-Apr-09	Eraring	1.00	0.101	0.10
6-Apr-09	Bayswater	0.99	0.101	0.10
7-Apr-09	Bayswater	0.99	0.101	0.10
8-Apr-09	Tallawarra	0.47	0.101	0.05
9-Apr-09	Bayswater	0.99	0.101	0.10
10-Apr-09	Bayswater	0.99	0.101	0.10
11-Apr-09	Liddell	1.08	0.101	0.11
12-Apr-09	Bayswater	0.99	0.101	0.10
13-Apr-09	Bayswater	0.99	0.101	0.10
14-Apr-09	Wallerawang C	1.05	0.101	0.11
15-Apr-09	Wallerawang C	1.05	0.101	0.11
16-Apr-09	Wallerawang C	1.05	0.101	0.11
17-Apr-09	Tallawarra	0.47	0.101	0.05
18-Apr-09	Wallerawang C	1.05	0.101	0.11
19-Apr-09	Eraring	1.00	0.101	0.10
20-Apr-09	Eraring	1.00	0.101	0.10
21-Apr-09	Eraring	1.00	0.101	0.10
22-Apr-09	Mt Piper	0.94	0.101	0.09
23-Apr-09	Uranquinty	0.74	0.101	0.07
24-Apr-09	Tumut 1 & 2	0.00	0.101	0.00
25-Apr-09	Liddell	1.08	0.101	0.11
26-Apr-09	Eraring	1.00	0.101	0.10
27-Apr-09	Tumut 1 & 2	0.00	0.101	0.00
28-Apr-09	Uranquinty	0.74	0.101	0.07
29-Apr-09	Tumut 1 & 2	0.00	0.101	0.00
30-Apr-09	Eraring	1.00	0.101	0.10
1-May-09	Guthega	0.00	0.101	0.00
2-May-09	Tallawarra	0.47	0.101	0.05
3-May-09	Guthega	0.00	0.101	0.00
4-May-09	Tumut 1 & 2	0.00	0.101	0.00
5-May-09	Tumut 1 & 2	0.00	0.101	0.00
6-May-09	Bayswater	0.99	0.101	0.10
7-May-09	Eraring	1.00	0.101	0.10
8-May-09	Tumut 3	0.00	0.101	0.00
9-May-09	Vales Point B	1.00	0.101	0.10
10-May-09	Vales Point B	1.00	0.101	0.10
11-May-09	Tumut 3	0.00	0.101	0.00
12-May-09	Vales Point B	1.00	0.101	0.10
13-May-09	Tumut 3	0.00	0.101	0.00
14-May-09	Tumut 1 & 2	0.00	0.101	0.00
15-May-09	Tumut 1 & 2	0.00	0.101	0.00
16-May-09	Tumut 1 & 2	0.00	0.101	0.00
17-May-09	Liddell	1.08	0.101	0.11
18-May-09	Uranquinty	0.74	0.101	0.07
19-May-09	Bayswater	0.99	0.101	0.10

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
20-May-09	Tumut 1 & 2	0.00	0.101	0.00
21-May-09	Vales Point B	1.00	0.101	0.10
22-May-09	Vales Point B	1.00	0.101	0.10
23-May-09	Eraring	1.00	0.101	0.10
24-May-09	Eraring	1.00	0.101	0.10
25-May-09	Uranquinty	0.74	0.101	0.07
26-May-09	Tumut 1 & 2	0.00	0.101	0.00
27-May-09	Uranquinty	0.74	0.101	0.07
28-May-09	Vales Point B	1.00	0.101	0.10
29-May-09	Tumut 1 & 2	0.00	0.101	0.00
30-May-09	Tumut 1 & 2	0.00	0.101	0.00
31-May-09	Uranquinty	0.00	0.101	0.00
1-Jun-09	Vales Point B	1.00	0.101	0.10
2-Jun-09	Uranquinty	0.74	0.101	0.07
3-Jun-09	Uranquinty	0.74	0.101	0.07
4-Jun-09	Vales Point B	1.00	0.101	0.10
5-Jun-09	Guthega	0.00	0.101	0.00
6-Jun-09	Vales Point B	1.00	0.101	0.10
7-Jun-09	Vales Point B	1.00	0.101	0.10
8-Jun-09	Eraring	1.00	0.101	0.10
9-Jun-09	Vales Point B	1.00	0.101	0.10
10-Jun-09	Mt Piper	0.94	0.101	0.09
11-Jun-09	Tumut 3	0.00	0.101	0.00
12-Jun-09	Uranquinty	0.74	0.101	0.07
13-Jun-09	Mt Piper	0.94	0.101	0.09
14-Jun-09	Vales Point B	1.00	0.101	0.10
15-Jun-09	Tumut 3	0.00	0.101	0.00
16-Jun-09	Liddell	1.08	0.101	0.11
17-Jun-09	Bayswater	0.99	0.101	0.10
18-Jun-09	Tumut 1 & 2	0.00	0.101	0.00
19-Jun-09	Mt Piper	0.94	0.101	0.09
20-Jun-09	Bayswater	0.99	0.101	0.10
21-Jun-09	Bayswater	0.99	0.101	0.10
22-Jun-09	Vales Point B	1.00	0.101	0.10
23-Jun-09	Bayswater	0.99	0.101	0.10
24-Jun-09	Liddell	1.08	0.101	0.11
25-Jun-09	Vales Point B	1.00	0.101	0.10
26-Jun-09	Liddell	1.08	0.101	0.11
27-Jun-09	Vales Point B	1.00	0.101	0.10
28-Jun-09	Bayswater	0.99	0.101	0.10
29-Jun-09	Bayswater	0.99	0.101	0.10
30-Jun-09	Bayswater	0.99	0.101	0.10
1-Jul-09	Bayswater	0.99	0.101	0.10
2-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
3-Jul-09	Colongra	0.74	0.101	0.07
4-Jul-09	Eraring	1.00	0.101	0.10
5-Jul-09	Vales Point B	1.00	0.101	0.10
6-Jul-09	Uranquinty	0.74	0.101	0.07
7-Jul-09	Colongra	0.74	0.101	0.07

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
8-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
9-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
10-Jul-09	Uranquinty	0.74	0.101	0.07
11-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
12-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
13-Jul-09	Uranquinty	0.74	0.101	0.07
14-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
15-Jul-09	Uranquinty	0.74	0.101	0.07
16-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
17-Jul-09	Uranquinty	0.74	0.101	0.07
18-Jul-09	Colongra	0.74	0.101	0.07
19-Jul-09	Liddell	1.08	0.101	0.11
20-Jul-09	Vales Point B	1.00	0.101	0.10
21-Jul-09	Colongra	0.74	0.101	0.07
22-Jul-09	Wallerawang C	1.05	0.101	0.11
23-Jul-09	Mt Piper	0.94	0.101	0.09
24-Jul-09	Colongra	0.74	0.101	0.07
25-Jul-09	Colongra	0.74	0.101	0.07
26-Jul-09	Tumut 3	0.00	0.101	0.00
27-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
28-Jul-09	Uranquinty	0.74	0.101	0.07
29-Jul-09	Vales Point B	1.00	0.101	0.10
30-Jul-09	Tumut 1 & 2	0.00	0.101	0.00
31-Jul-09	Vales Point B	1.00	0.101	0.10
1-Aug-09	Colongra	0.74	0.101	0.07
2-Aug-09	Liddell	1.08	0.101	0.11
3-Aug-09	Bayswater	0.99	0.101	0.10
4-Aug-09	Bayswater	0.99	0.101	0.10
5-Aug-09	Wallerawang C	1.05	0.101	0.11
6-Aug-09	Wallerawang C	1.05	0.101	0.11
7-Aug-09	Colongra	0.74	0.101	0.07
8-Aug-09	Colongra	0.74	0.101	0.07
9-Aug-09	Wallerawang C	1.05	0.101	0.11
10-Aug-09	Colongra	0.74	0.101	0.07
11-Aug-09	Colongra	0.74	0.101	0.07
12-Aug-09	Bayswater	0.99	0.101	0.10
13-Aug-09	Wallerawang C	1.05	0.101	0.11
14-Aug-09	Liddell	1.08	0.101	0.11
15-Aug-09	Bayswater	0.99	0.101	0.10
16-Aug-09	Vales Point B	1.00	0.101	0.10
17-Aug-09	Bayswater	0.99	0.101	0.10
18-Aug-09	Liddell	1.08	0.101	0.11
19-Aug-09	Bayswater	0.99	0.101	0.10
20-Aug-09	Mt Piper	0.94	0.101	0.09
21-Aug-09	Bayswater	0.99	0.101	0.10
22-Aug-09	Bayswater	0.99	0.101	0.10
23-Aug-09	Colongra	0.74	0.101	0.07
24-Aug-09	Eraring	1.00	0.101	0.10
25-Aug-09	Uranquinty	0.74	0.101	0.07

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
26-Aug-09	Vales Point B	1.00	0.101	0.10
27-Aug-09	Bayswater	0.99	0.101	0.10
28-Aug-09	Munmorah	1.16	0.101	0.12
29-Aug-09	Bayswater	0.99	0.101	0.10
30-Aug-09	Bayswater	0.99	0.101	0.10
31-Aug-09	Bayswater	0.99	0.101	0.10
1-Sep-09	Tumut 1 & 2	0.00	0.101	0.00
2-Sep-09	Tumut 1 & 2	0.00	0.101	0.00
3-Sep-09	Tumut 1 & 2	0.00	0.101	0.00
4-Sep-09	Wallerawang C	1.05	0.101	0.11
5-Sep-09	Vales Point B	1.00	0.101	0.10
6-Sep-09	Tallawarra	0.47	0.101	0.05
7-Sep-09	Tumut 3	0.00	0.101	0.00
8-Sep-09	Tumut 1 & 2	0.00	0.101	0.00
9-Sep-09	Vales Point B	1.00	0.101	0.10
10-Sep-09	Munmorah	1.16	0.101	0.12
11-Sep-09	Bayswater	0.99	0.101	0.10
12-Sep-09	Bayswater	0.99	0.101	0.10
13-Sep-09	Liddell	1.08	0.101	0.11
14-Sep-09	Vales Point B	1.00	0.101	0.10
15-Sep-09	Tallawarra	0.47	0.101	0.05
16-Sep-09	Vales Point B	1.00	0.101	0.10
17-Sep-09	Uranquinty	0.74	0.101	0.07
18-Sep-09	Colongra	0.74	0.101	0.07
19-Sep-09	Wallerawang C	1.05	0.101	0.11
20-Sep-09	Wallerawang C	1.05	0.101	0.11
21-Sep-09	Colongra	0.74	0.101	0.07
22-Sep-09	Vales Point B	1.00	0.101	0.10
23-Sep-09	Wallerawang C	1.05	0.101	0.11
24-Sep-09	Tallawarra	0.47	0.101	0.05
25-Sep-09	Munmorah	1.16	0.101	0.12
26-Sep-09	Wallerawang C	1.05	0.101	0.11
27-Sep-09	Vales Point B	1.00	0.101	0.10
28-Sep-09	Wallerawang C	1.05	0.101	0.11
29-Sep-09	Wallerawang C	1.05	0.101	0.11
30-Sep-09	Wallerawang C	1.05	0.101	0.11
			Total	27.75

Table 6 (page 49) presents an example calculation, using the Modified Marginal Historical Emissions Method, of the total emissions that would be released by the households using electrical room heaters. The table shows the marginal power plant between 6.00 pm and 10.00 pm on each of the days during the 12 month period. Table 5 also shows the emissions factors of each of these power plants and the corresponding daily emissions resulting from the 101 kWh (including losses) each day of electricity used during the specified time period in “summer” period and 202 kWh (including losses) of electricity used during the during the specified time period in “winter”.

Table 6. Example Calculation of Emissions Released from Room Heating with Electrical Appliances in the Binda-Bigga Demand Management Project				
Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
1-Oct-08	Eraring	1.00	0.101	0.10
2-Oct-08	Tumut 1&2	0.00	0.101	0.00
3-Oct-08	Eraring	1.00	0.101	0.10
4-Oct-08	Eraring	1.00	0.101	0.10
5-Oct-08	Bayswater	0.99	0.101	0.10
6-Oct-08	Bayswater	0.99	0.101	0.10
7-Oct-08	Eraring	1.00	0.101	0.10
8-Oct-08	Bayswater	0.99	0.101	0.10
9-Oct-08	Eraring	1.00	0.101	0.10
10-Oct-08	Eraring	1.00	0.101	0.10
11-Oct-08	Bayswater	0.99	0.101	0.10
12-Oct-08	Liddell	1.08	0.101	0.11
13-Oct-08	Bayswater	0.99	0.101	0.10
14-Oct-08	Bayswater	0.99	0.101	0.10
15-Oct-08	Bayswater	0.99	0.101	0.10
16-Oct-08	Bayswater	0.99	0.101	0.10
17-Oct-08	Bayswater	0.99	0.101	0.10
18-Oct-08	Vales Point B	1.00	0.101	0.10
19-Oct-08	Bayswater	0.99	0.101	0.10
20-Oct-08	Bayswater	0.99	0.101	0.10
21-Oct-08	Bayswater	0.99	0.101	0.10
22-Oct-08	Bayswater	0.99	0.101	0.10
23-Oct-08	Tumut 1&2	0.00	0.101	0.00
24-Oct-08	Bayswater	0.99	0.101	0.10
25-Oct-08	Bayswater	0.99	0.101	0.10
26-Oct-08	Bayswater	0.99	0.101	0.10
27-Oct-08	Liddell	1.08	0.101	0.11
28-Oct-08	Tumut 1&2	0.00	0.101	0.00
29-Oct-08	Bayswater	0.99	0.101	0.10
30-Oct-08	Liddell	1.08	0.101	0.11
31-Oct-08	Tumut 1&2	0.00	0.101	0.00
1-Nov-08	Liddell	1.08	0.101	0.11
2-Nov-08	Liddell	1.08	0.101	0.11
3-Nov-08	Bayswater	0.99	0.101	0.10
4-Nov-08	Bayswater	0.99	0.101	0.10
5-Nov-08	Bayswater	0.99	0.101	0.10
6-Nov-08	Bayswater	0.99	0.101	0.10
7-Nov-08	Bayswater	0.99	0.101	0.10
8-Nov-08	Bayswater	0.99	0.101	0.10
9-Nov-08	Bayswater	0.99	0.101	0.10
10-Nov-08	Bayswater	0.99	0.101	0.10
11-Nov-08	Bayswater	0.99	0.101	0.10

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
12-Nov-08	Eraring	1.00	0.101	0.10
13-Nov-08	Eraring	1.00	0.101	0.10
14-Nov-08	Eraring	1.00	0.101	0.10
15-Nov-08	Bayswater	0.99	0.101	0.10
16-Nov-08	Bayswater	0.99	0.101	0.10
17-Nov-08	Bayswater	0.99	0.101	0.10
18-Nov-08	Eraring	1.00	0.101	0.10
19-Nov-08	Bayswater	0.99	0.101	0.10
20-Nov-08	Tallawarra	0.47	0.101	0.05
21-Nov-08	Bayswater	0.99	0.101	0.10
22-Nov-08	Bayswater	0.99	0.101	0.10
23-Nov-08	Bayswater	0.99	0.101	0.10
24-Nov-08	Bayswater	0.99	0.101	0.10
25-Nov-08	Bayswater	0.99	0.101	0.10
26-Nov-08	Bayswater	0.99	0.101	0.10
27-Nov-08	Bayswater	0.99	0.101	0.10
28-Nov-08	Bayswater	0.99	0.101	0.10
29-Nov-08	Bayswater	0.99	0.101	0.10
30-Nov-08	Bayswater	0.99	0.101	0.10
1-Dec-08	Bayswater	0.99	0.101	0.10
2-Dec-08	Bayswater	0.99	0.101	0.10
3-Dec-08	Bayswater	0.99	0.101	0.10
4-Dec-08	Bayswater	0.99	0.101	0.10
5-Dec-08	Eraring	1.00	0.101	0.10
6-Dec-08	Bayswater	0.99	0.101	0.10
7-Dec-08	Bayswater	0.99	0.101	0.10
8-Dec-08	Bayswater	0.99	0.101	0.10
9-Dec-08	Bayswater	0.99	0.101	0.10
10-Dec-08	Bayswater	0.99	0.101	0.10
11-Dec-08	Bayswater	0.99	0.101	0.10
12-Dec-08	Mt Piper	0.94	0.101	0.09
13-Dec-08	Mt Piper	0.94	0.101	0.09
14-Dec-08	Mt Piper	0.94	0.101	0.09
15-Dec-08	Bayswater	0.99	0.101	0.10
16-Dec-08	Bayswater	0.99	0.101	0.10
17-Dec-08	Bayswater	0.99	0.101	0.10
18-Dec-08	Bayswater	0.99	0.101	0.10
19-Dec-08	Bayswater	0.99	0.101	0.10
20-Dec-08	Eraring	1.00	0.101	0.10
21-Dec-08	Vales Point B	1.00	0.101	0.10
22-Dec-08	Bayswater	0.99	0.101	0.10
23-Dec-08	Bayswater	0.99	0.101	0.10
24-Dec-08	Bayswater	0.99	0.101	0.10
25-Dec-08	Eraring	1.00	0.101	0.10
26-Dec-08	Bayswater	0.99	0.101	0.10
27-Dec-08	Bayswater	0.99	0.101	0.10
28-Dec-08	Bayswater	0.99	0.101	0.10
29-Dec-08	Bayswater	0.99	0.101	0.10
30-Dec-08	Bayswater	0.99	0.101	0.10
31-Dec-08	Mt Piper	0.94	0.101	0.09
1-Jan-09	Bayswater	0.99	0.101	0.10

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
2-Jan-09	Bayswater	0.99	0.101	0.10
3-Jan-09	Bayswater	0.99	0.101	0.10
4-Jan-09	Bayswater	0.99	0.101	0.10
5-Jan-09	Eraring	1.00	0.101	0.10
6-Jan-09	Eraring	1.00	0.101	0.10
7-Jan-09	Eraring	1.00	0.101	0.10
8-Jan-09	Bayswater	0.99	0.101	0.10
9-Jan-09	Liddell	1.08	0.101	0.11
10-Jan-09	Bayswater	0.99	0.101	0.10
11-Jan-09	Bayswater	0.99	0.101	0.10
12-Jan-09	Bayswater	0.99	0.101	0.10
13-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
14-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
15-Jan-09	Bayswater	0.99	0.101	0.10
16-Jan-09	Bayswater	0.99	0.101	0.10
17-Jan-09	Bayswater	0.99	0.101	0.10
18-Jan-09	Bayswater	0.99	0.101	0.10
19-Jan-09	Eraring	1.00	0.101	0.10
20-Jan-09	Bayswater	0.99	0.101	0.10
21-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
22-Jan-09	Bayswater	0.99	0.101	0.10
23-Jan-09	Liddell	1.08	0.101	0.11
24-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
25-Jan-09	Eraring	1.00	0.101	0.10
26-Jan-09	Tallawarra	0.47	0.101	0.05
27-Jan-09	Bayswater	0.99	0.101	0.10
28-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
29-Jan-09	Tumut 3	0.00	0.101	0.00
30-Jan-09	Tumut 1 & 2	0.00	0.101	0.00
31-Jan-09	Eraring	1.00	0.101	0.10
1-Feb-09	Bayswater	0.99	0.101	0.10
2-Feb-09	Bayswater	0.99	0.101	0.10
3-Feb-09	Bayswater	0.99	0.101	0.10
4-Feb-09	Bayswater	0.99	0.101	0.10
5-Feb-09	Tumut 1 & 2	0.00	0.101	0.00
6-Feb-09	Tumut 3	0.00	0.101	0.00
7-Feb-09	Tumut 3	0.00	0.101	0.00
8-Feb-09	Tumut 1 & 2	0.00	0.101	0.00
9-Feb-09	Bayswater	0.99	0.101	0.10
10-Feb-09	Bayswater	0.99	0.101	0.10
11-Feb-09	Eraring	1.00	0.101	0.10
12-Feb-09	Bayswater	0.99	0.101	0.10
13-Feb-09	Bayswater	0.99	0.101	0.10
14-Feb-09	Bayswater	0.99	0.101	0.10
15-Feb-09	Bayswater	0.99	0.101	0.10
16-Feb-09	Bayswater	0.99	0.101	0.10
17-Feb-09	Bayswater	0.99	0.101	0.10
18-Feb-09	Bayswater	0.99	0.101	0.10
19-Feb-09	Bayswater	0.99	0.101	0.10

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
20-Feb-09	Bayswater	0.99	0.101	0.10
21-Feb-09	Bayswater	0.99	0.101	0.10
22-Feb-09	Bayswater	0.99	0.101	0.10
23-Feb-09	Bayswater	0.99	0.101	0.10
24-Feb-09	Bayswater	0.99	0.101	0.10
25-Feb-09	Bayswater	0.99	0.101	0.10
26-Feb-09	Tallawarra	0.47	0.101	0.05
27-Feb-09	Bayswater	0.99	0.101	0.10
28-Feb-09	Mt Piper	0.94	0.101	0.09
1-Mar-09	Bayswater	0.99	0.101	0.10
2-Mar-09	Bayswater	0.99	0.101	0.10
3-Mar-09	Bayswater	0.99	0.101	0.10
4-Mar-09	Bayswater	0.99	0.101	0.10
5-Mar-09	Bayswater	0.99	0.101	0.10
6-Mar-09	Bayswater	0.99	0.101	0.10
7-Mar-09	Bayswater	0.99	0.101	0.10
8-Mar-09	Mt Piper	0.94	0.101	0.09
9-Mar-09	Bayswater	0.99	0.101	0.10
10-Mar-09	Bayswater	0.99	0.101	0.10
11-Mar-09	Bayswater	0.99	0.101	0.10
12-Mar-09	Bayswater	0.99	0.101	0.10
13-Mar-09	Bayswater	0.99	0.101	0.10
14-Mar-09	Bayswater	0.99	0.101	0.10
15-Mar-09	Bayswater	0.99	0.101	0.10
16-Mar-09	Bayswater	0.99	0.101	0.10
17-Mar-09	Bayswater	0.99	0.101	0.10
18-Mar-09	Bayswater	0.99	0.101	0.10
19-Mar-09	Bayswater	0.99	0.101	0.10
20-Mar-09	Bayswater	0.99	0.101	0.10
21-Mar-09	Bayswater	0.99	0.101	0.10
22-Mar-09	Bayswater	0.99	0.101	0.10
23-Mar-09	Bayswater	0.99	0.101	0.10
24-Mar-09	Bayswater	0.99	0.101	0.10
25-Mar-09	Bayswater	0.99	0.101	0.10
26-Mar-09	Bayswater	0.99	0.101	0.10
27-Mar-09	Bayswater	0.99	0.101	0.10
28-Mar-09	Bayswater	0.99	0.101	0.10
29-Mar-09	Bayswater	0.99	0.101	0.10
30-Mar-09	Bayswater	0.99	0.101	0.10
31-Mar-09	Bayswater	0.99	0.101	0.10
1-Apr-09	Bayswater	0.99	0.202	0.20
2-Apr-09	Tumut 1 & 2	0.00	0.202	0.00
3-Apr-09	Bayswater	0.99	0.202	0.20
4-Apr-09	Bayswater	0.99	0.202	0.20
5-Apr-09	Bayswater	0.99	0.202	0.20
6-Apr-09	Uranquinty	0.74	0.202	0.15
7-Apr-09	Bayswater	0.99	0.202	0.20
8-Apr-09	Bayswater	0.99	0.202	0.20
9-Apr-09	Bayswater	0.99	0.202	0.20

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
10-Apr-09	Bayswater	0.99	0.202	0.20
11-Apr-09	Bayswater	0.99	0.202	0.20
12-Apr-09	Bayswater	0.99	0.202	0.20
13-Apr-09	Bayswater	0.99	0.202	0.20
14-Apr-09	Mt Piper	0.94	0.202	0.19
15-Apr-09	Tumut 1 & 2	0.00	0.202	0.00
16-Apr-09	Tumut 1 & 2	0.00	0.202	0.00
17-Apr-09	Uranquinty	0.74	0.202	0.15
18-Apr-09	Tallawarra	0.47	0.202	0.09
19-Apr-09	Tallawarra	0.47	0.202	0.09
20-Apr-09	Uranquinty	0.74	0.202	0.15
21-Apr-09	Uranquinty	0.74	0.202	0.15
22-Apr-09	Uranquinty	0.74	0.202	0.15
23-Apr-09	Tallawarra	0.47	0.202	0.09
24-Apr-09	Bayswater	0.99	0.202	0.20
25-Apr-09	Bayswater	0.99	0.202	0.20
26-Apr-09	Eraring	1.00	0.202	0.20
27-Apr-09	Tumut 1 & 2	0.00	0.202	0.00
28-Apr-09	Tumut 3	0.00	0.202	0.00
29-Apr-09	Uranquinty	0.74	0.202	0.15
30-Apr-09	Uranquinty	0.74	0.202	0.15
1-May-09	Tallawarra	0.47	0.202	0.09
2-May-09	Tallawarra	0.47	0.202	0.09
3-May-09	Tallawarra	0.47	0.202	0.09
4-May-09	Tallawarra	0.47	0.202	0.09
5-May-09	Uranquinty	0.74	0.202	0.15
6-May-09	Tumut 1 & 2	0.00	0.202	0.00
7-May-09	Eraring	1.00	0.202	0.20
8-May-09	Tumut 1 & 2	0.00	0.202	0.00
9-May-09	Eraring	1.00	0.202	0.20
10-May-09	Tallawarra	0.47	0.202	0.09
11-May-09	Uranquinty	0.74	0.202	0.15
12-May-09	Tumut 1 & 2	0.00	0.202	0.00
13-May-09	Tumut 1 & 2	0.00	0.202	0.00
14-May-09	Tumut 3	0.00	0.202	0.00
15-May-09	Tumut 1 & 2	0.00	0.202	0.00
16-May-09	Liddell	1.08	0.202	0.22
17-May-09	Liddell	1.08	0.202	0.22
18-May-09	Uranquinty	0.74	0.202	0.15
19-May-09	Uranquinty	0.74	0.202	0.15
20-May-09	Uranquinty	0.74	0.202	0.15
21-May-09	Tumut 1 & 2	0.00	0.202	0.00
22-May-09	Liddell	1.08	0.202	0.22
23-May-09	Bayswater	0.99	0.202	0.20
24-May-09	Bayswater	0.99	0.202	0.20
25-May-09	Uranquinty	0.74	0.202	0.15
26-May-09	Tumut 1 & 2	0.00	0.202	0.00
27-May-09	Tumut 1 & 2	0.00	0.202	0.00
28-May-09	Tumut 1 & 2	0.00	0.202	0.00

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
29-May-09	Uranquinty	0.74	0.202	0.15
30-May-09	Liddell	1.08	0.202	0.22
31-May-09	Mt Piper	0.94	0.202	0.19
1-Jun-09	Uranquinty	0.74	0.202	0.15
2-Jun-09	Vales Point B	1.00	0.202	0.20
3-Jun-09	Uranquinty	0.74	0.202	0.15
4-Jun-09	Uranquinty	0.74	0.202	0.15
5-Jun-09	Liddell	1.08	0.202	0.22
6-Jun-09	Bayswater	0.99	0.202	0.20
7-Jun-09	Mt Piper	0.94	0.202	0.19
8-Jun-09	Bayswater	0.99	0.202	0.20
9-Jun-09	Tumut 3	0.00	0.202	0.00
10-Jun-09	Tumut 3	0.00	0.202	0.00
11-Jun-09	Tumut 3	0.00	0.202	0.00
12-Jun-09	Uranquinty	0.74	0.202	0.15
13-Jun-09	Bayswater	0.99	0.202	0.20
14-Jun-09	Uranquinty	0.74	0.202	0.15
15-Jun-09	Tumut 1 & 2	0.00	0.202	0.00
16-Jun-09	Bayswater	0.99	0.202	0.20
17-Jun-09	Bayswater	0.99	0.202	0.20
18-Jun-09	Uranquinty	0.74	0.202	0.15
19-Jun-09	Bayswater	0.99	0.202	0.20
20-Jun-09	Bayswater	0.99	0.202	0.20
21-Jun-09	Bayswater	0.99	0.202	0.20
22-Jun-09	Bayswater	0.99	0.202	0.20
23-Jun-09	Bayswater	0.99	0.202	0.20
24-Jun-09	Bayswater	0.99	0.202	0.20
25-Jun-09	Bayswater	0.99	0.202	0.20
26-Jun-09	Bayswater	0.99	0.202	0.20
27-Jun-09	Liddell	1.08	0.202	0.22
28-Jun-09	Bayswater	0.99	0.202	0.20
29-Jun-09	Bayswater	0.99	0.202	0.20
30-Jun-09	Bayswater	0.99	0.202	0.20
1-Jul-09	Bayswater	0.99	0.202	0.20
2-Jul-09	Bayswater	0.99	0.202	0.20
3-Jul-09	Tumut 3	0.00	0.202	0.00
4-Jul-09	Eraring	1.00	0.202	0.20
5-Jul-09	Eraring	1.00	0.202	0.20
6-Jul-09	Tumut 3	0.00	0.202	0.00
7-Jul-09	Eraring	1.00	0.202	0.20
8-Jul-09	Eraring	1.00	0.202	0.20
9-Jul-09	Eraring	1.00	0.202	0.20
10-Jul-09	Eraring	1.00	0.202	0.20
11-Jul-09	Eraring	1.00	0.202	0.20
12-Jul-09	Eraring	1.00	0.202	0.20
13-Jul-09	Eraring	1.00	0.202	0.20
14-Jul-09	Eraring	1.00	0.202	0.20
15-Jul-09	Eraring	1.00	0.202	0.20
16-Jul-09	Eraring	1.00	0.202	0.20

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
17-Jul-09	Eraring	1.00	0.202	0.20
18-Jul-09	Eraring	1.00	0.202	0.20
19-Jul-09	Eraring	1.00	0.202	0.20
20-Jul-09	Eraring	1.00	0.202	0.20
21-Jul-09	Eraring	1.00	0.202	0.20
22-Jul-09	Eraring	1.00	0.202	0.20
23-Jul-09	Eraring	1.00	0.202	0.20
24-Jul-09	Eraring	1.00	0.202	0.20
25-Jul-09	Eraring	1.00	0.202	0.20
26-Jul-09	Eraring	1.00	0.202	0.20
27-Jul-09	Eraring	1.00	0.202	0.20
28-Jul-09	Eraring	1.00	0.202	0.20
29-Jul-09	Tumut 3	0.00	0.202	0.00
30-Jul-09	Tumut 3	0.00	0.202	0.00
31-Jul-09	Colongra	0.74	0.202	0.15
1-Aug-09	Liddell	1.08	0.202	0.22
2-Aug-09	Liddell	1.08	0.202	0.22
3-Aug-09	Eraring	1.00	0.202	0.20
4-Aug-09	Uranquinty	0.74	0.202	0.15
5-Aug-09	Tumut 1 & 2	0.00	0.202	0.00
6-Aug-09	Bayswater	0.99	0.202	0.20
7-Aug-09	Tallawarra	0.47	0.202	0.09
8-Aug-09	Liddell	1.08	0.202	0.22
9-Aug-09	Bayswater	0.99	0.202	0.20
10-Aug-09	Mt Piper	0.94	0.202	0.19
11-Aug-09	Eraring	1.00	0.202	0.20
12-Aug-09	Bayswater	0.99	0.202	0.20
13-Aug-09	Bayswater	0.99	0.202	0.20
14-Aug-09	Bayswater	0.99	0.202	0.20
15-Aug-09	Vales Point B	1.00	0.202	0.20
16-Aug-09	Vales Point B	1.00	0.202	0.20
17-Aug-09	Liddell	1.08	0.202	0.22
18-Aug-09	Eraring	1.00	0.202	0.20
19-Aug-09	Bayswater	0.99	0.202	0.20
20-Aug-09	Bayswater	0.99	0.202	0.20
21-Aug-09	Bayswater	0.99	0.202	0.20
22-Aug-09	Bayswater	0.99	0.202	0.20
23-Aug-09	Bayswater	0.99	0.202	0.20
24-Aug-09	Bayswater	0.99	0.202	0.20
25-Aug-09	Uranquinty	0.74	0.202	0.15
26-Aug-09	Bayswater	0.99	0.202	0.20
27-Aug-09	Bayswater	0.99	0.202	0.20
28-Aug-09	Mt Piper	0.94	0.202	0.19
29-Aug-09	Liddell	1.08	0.202	0.22
30-Aug-09	Liddell	1.08	0.202	0.22
31-Aug-09	Bayswater	0.99	0.202	0.20
1-Sep-09	Tumut 1 & 2	0.00	0.202	0.00
2-Sep-09	Tumut 1 & 2	0.00	0.202	0.00
3-Sep-09	Liddell	1.08	0.202	0.22

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Electricity Use (including losses) (MWh)	Emissions Released (tCO2-e)
4-Sep-09	Uranquinty	0.74	0.202	0.15
5-Sep-09	Tallawarra	0.47	0.202	0.09
6-Sep-09	Bayswater	0.99	0.202	0.20
7-Sep-09	Uranquinty	0.74	0.202	0.15
8-Sep-09	Eraring	1.00	0.202	0.20
9-Sep-09	Tumut 3	0.00	0.202	0.00
10-Sep-09	Tallawarra	0.47	0.202	0.09
11-Sep-09	Bayswater	0.99	0.202	0.20
12-Sep-09	Bayswater	0.99	0.202	0.20
13-Sep-09	Bayswater	0.99	0.202	0.20
14-Sep-09	Tallawarra	0.47	0.202	0.09
15-Sep-09	Tallawarra	0.47	0.202	0.09
16-Sep-09	Bayswater	0.99	0.202	0.20
17-Sep-09	Uranquinty	0.74	0.202	0.15
18-Sep-09	Bayswater	0.99	0.202	0.20
19-Sep-09	Eraring	1.00	0.202	0.20
20-Sep-09	Bayswater	0.99	0.202	0.20
21-Sep-09	Bayswater	0.99	0.202	0.20
22-Sep-09	Bayswater	0.99	0.202	0.20
23-Sep-09	Bayswater	0.99	0.202	0.20
24-Sep-09	Bayswater	0.99	0.202	0.20
25-Sep-09	Tallawarra	0.47	0.202	0.09
26-Sep-09	Eraring	1.00	0.202	0.20
27-Sep-09	Bayswater	0.99	0.202	0.20
28-Sep-09	Uranquinty	0.74	0.202	0.15
29-Sep-09	Tumut 3	0.00	0.202	0.00
30-Sep-09	Bayswater	0.99	0.202	0.20
			Total	45.02

From Table 4 (page 40), the emissions released from cooking and room heating with gas appliances = 18.2 tCO_2-e.

Table 7 shows the total emissions reduction that would be achieved by the Binda-Bigga Demand Management Project during the 12 month period, based on the assumptions outlined above.

Table 7. Example Calculation of Emissions Reduction Achieved by the Binda-Bigga Demand Management Project	
Activity	**Emissions (tCO2-e)**
Use of Electrical Appliances	72.8
Use of Gas Appliances	18.2
Emissions Reduction Achieved	**54.6**

4.5 Castle Hill Demand Management Program

4.5.1 Project Description

Integral Energy Network distributes electricity to over 2.1 million people in households and businesses across 24,500 square kilometres of Greater Western Sydney, the Illawarra region and the Southern Highlands of the State of New South Wales.

Castle Hill is a rapidly developing suburb located 32 kilometres north west of the Sydney central business district. In 2005, the Castle Hill local electricity network had 5,320 residential customer connections and 679 business and community connections.

Over the five years from 2000 to 2005, electricity consumption in Castle Hill increased by 32% and Integral Energy forecasts showed that this would grow by a further 54% over the subsequent 10 years. Increasing penetration and use of air conditioners in the Castle Hill commercial centre and surrounding residential areas would result in summer peak loads exceeding system capability.

Peak demand in the Castle Hill area is primarily driven by use of domestic and commercial air-conditioning on hot summer days, particularly when there are several days in a row with temperatures exceeding 35^{o}C.

In 2003, the Sustainable Energy Development Authority (SEDA) was contracted by Integral Energy to work with electricity customers to relieve the peak summer electrical demand on the Castle Hill zone substation by 1,350kVA, approximately 4% of the peak electrical load on the local network, over a three year period. The aim of the contract was to defer the need for the upgrade of the Castle Hill zone substation by reducing the demand for electricity during peak periods, namely from 1pm until 5pm on summer weekdays when the temperature reached or exceeded 35^{o}C.

Initial investigations into the top 20 energy users in the area served by the Castle Hill zone substation identified the Castle Towers Shopping Centre and its major retail tenants as potential targets for peak demand management initiatives. The top ten commercial energy users had a combined electrical load of greater than 10MVA. Consequently, 1.35MVA represented an average drop of 13% of their load.

Preliminary walk through energy audits of the shopping centre and the major retail tenants suggested good potential to improve the efficiency of lighting, ventilation and air conditioning systems. These systems account for an estimated 70% of commercial sector electricity demand during times of the peak summer load on the New South Wales network.

SEDA modified its existing Energy Smart Business program to assist the major energy consumers in the Castle Towers Shopping Centre to identify and implement cost effective peak demand reduction projects. The DSM measures targeted included interruptible loads, the installation of high efficiency air conditioning (and the upgrading of existing air conditioning systems), and the installation of efficient lighting and power factor correction equipment in new and replacement applications. The contracts with electricity customers were performance based, with payment on verification of demand reduction.

4.5.2 Example Calculation of Emissions Reduction

The example calculation was carried out for the 12 months between October 2008 and September 2009. We assumed that the DSM measures implemented in the Castle Towers Shopping Centre operated over a 10 hour period from 8 am to 6 pm every day[55]. We also assumed that the load reduction from these measures was 1.35MVA (1.45 MVA including losses).

4.5.2.1 Average Grid Emissions Method

Shown below is an example calculation, using the Average Grid Emissions Method, of the total emissions reduction that would be achieved by the Castle Hill Demand Management Program during the summer of 2008/09, based on the assumptions outlined above.

Total energy saving achieved by the project (including losses): 5689.4 MWh

Average grid emissions factor for New South Wales: 0.90 tCO2-e/MWh

Emissions reduction achieved by the project: 5120.5 tCO2-e

4.5.2.1 Modified Marginal Historical Emissions Method

Table 8 (page 59) presents an example calculation, using the Modified Marginal Historical Emissions Method, of the total emissions reduction that would be achieved by the Castle Hill Demand Management Program during the 12 month period, based on the assumptions outlined above. The table shows the marginal power plant between 8.00 am and 6.00 pm on each day during the 12 month period[56]. Table 8 also shows the emissions factors of each of these power plants and the corresponding daily emissions reductions resulting from load reductions of 1.45 MVA (including losses) during the 10 hour period. The total emissions reduction that would be achieved from the Drummoyne program is shown at the bottom of the table.

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[55] The Castle Towers Shopping Centre is open every day on both weekdays and weekends. While the Castle Hill Demand Management Program was targeted at reducing peak load, most of the DSM measures implemented would be operating the whole time that the shopping centre was open.

[56] Because 10 hours is a relatively long time period, the marginal power plant was likely to change during the period. When this occurred, the marginal power plant was deemed to be the plant that was on the margin for the longest proportion of the 10 hour period.

Table 8. Example Calculation of Emissions Reduction Achieved by the Castle Hill Demand Management Program					
Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
1-Oct-08	Vales Point B	1.00	1.45	10.0	14.50
2-Oct-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
3-Oct-08	Liddell	1.08	1.45	10.0	15.66
4-Oct-08	Bayswater	0.99	1.45	10.0	14.36
5-Oct-08	Bayswater	0.99	1.45	10.0	14.36
6-Oct-08	Mt Piper	0.94	1.45	10.0	13.63
7-Oct-08	Mt Piper	0.94	1.45	10.0	13.63
8-Oct-08	Mt Piper	0.94	1.45	10.0	13.63
9-Oct-08	Bayswater	0.99	1.45	10.0	14.36
10-Oct-08	Eraring	1.00	1.45	10.0	14.50
11-Oct-08	Bayswater	0.99	1.45	10.0	14.36
12-Oct-08	Bayswater	0.99	1.45	10.0	14.36
13-Oct-08	Eraring	1.00	1.45	10.0	14.50
14-Oct-08	Eraring	1.00	1.45	10.0	14.50
15-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
16-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
17-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
18-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
19-Oct-08	Bayswater	0.99	1.45	10.0	14.36
20-Oct-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
21-Oct-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
22-Oct-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
23-Oct-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
24-Oct-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
25-Oct-08	Bayswater	0.99	1.45	10.0	14.36
26-Oct-08	Bayswater	0.99	1.45	10.0	14.36
27-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
28-Oct-08	Vales Point B	1.00	1.45	10.0	14.50
29-Oct-08	Munmorah	1.16	1.45	10.0	16.82
30-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
31-Oct-08	Tumut 3	0.00	1.45	10.0	0.00
1-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
2-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
3-Nov-08	Vales Point B	1.00	1.45	10.0	14.50
4-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
5-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
6-Nov-08	Tumut 1 & 2	0.00	1.45	10.0	0.00
7-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
8-Nov-08	Tallawarra	0.47	1.45	10.0	6.82
9-Nov-08	Liddell	1.08	1.45	10.0	15.66
10-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
11-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
12-Nov-08	Uranquinty	0.74	1.45	10.0	10.73
13-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
14-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
15-Nov-08	Tallawarra	0.47	1.45	10.0	6.82
16-Nov-08	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
17-Nov-08	Bayswater	0.99	1.45	10.0	14.36
18-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
19-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
20-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
21-Nov-08	Bayswater	0.99	1.45	10.0	14.36
22-Nov-08	Tallawarra	0.47	1.45	10.0	6.82
23-Nov-08	Bayswater	0.99	1.45	10.0	14.36
24-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
25-Nov-08	Tumut 3	0.00	1.45	10.0	0.00
26-Nov-08	Eraring	1.00	1.45	10.0	14.50
27-Nov-08	Eraring	1.00	1.45	10.0	14.50
28-Nov-08	Eraring	1.00	1.45	10.0	14.50
29-Nov-08	Bayswater	0.99	1.45	10.0	14.36
30-Nov-08	Mt Piper	0.94	1.45	10.0	13.63
1-Dec-08	Bayswater	0.99	1.45	10.0	14.36
2-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
3-Dec-08	Eraring	1.00	1.45	10.0	14.50
4-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
5-Dec-08	Eraring	1.00	1.45	10.0	14.50
6-Dec-08	Eraring	1.00	1.45	10.0	14.50
7-Dec-08	Bayswater	0.99	1.45	10.0	14.36
8-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
9-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
10-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
11-Dec-08	Eraring	1.00	1.45	10.0	14.50
12-Dec-08	Bayswater	0.99	1.45	10.0	14.36
13-Dec-08	Bayswater	0.99	1.45	10.0	14.36
14-Dec-08	Vales Point B	1.00	1.45	10.0	14.50
15-Dec-08	Bayswater	0.99	1.45	10.0	14.36
16-Dec-08	Bayswater	0.99	1.45	10.0	14.36
17-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
18-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
19-Dec-08	Tumut 3	0.00	1.45	10.0	0.00
20-Dec-08	Bayswater	0.99	1.45	10.0	14.36
21-Dec-08	Eraring	1.00	1.45	10.0	14.50
22-Dec-08	Bayswater	0.99	1.45	10.0	14.36
23-Dec-08	Bayswater	0.99	1.45	10.0	14.36
24-Dec-08	Bayswater	0.99	1.45	10.0	14.36
25-Dec-08	Eraring	1.00	1.45	10.0	14.50
26-Dec-08	Bayswater	0.99	1.45	10.0	14.36
27-Dec-08	Bayswater	0.99	1.45	10.0	14.36
28-Dec-08	Bayswater	0.99	1.45	10.0	14.36
29-Dec-08	Bayswater	0.99	1.45	10.0	14.36
30-Dec-08	Bayswater	0.99	1.45	10.0	14.36
31-Dec-08	Bayswater	0.99	1.45	10.0	14.36
1-Jan-09	Bayswater	0.99	1.45	10.0	14.36
2-Jan-09	Bayswater	0.99	1.45	10.0	14.36
3-Jan-09	Bayswater	0.99	1.45	10.0	14.36
4-Jan-09	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
5-Jan-09	Eraring	1.00	1.45	10.0	14.50
6-Jan-09	Tumut 3	0.00	1.45	10.0	0.00
7-Jan-09	Eraring	1.00	1.45	10.0	14.50
8-Jan-09	Eraring	1.00	1.45	10.0	14.50
9-Jan-09	Eraring	1.00	1.45	10.0	14.50
10-Jan-09	Bayswater	0.99	1.45	10.0	14.36
11-Jan-09	Bayswater	0.99	1.45	10.0	14.36
12-Jan-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
13-Jan-09	Eraring	1.00	1.45	10.0	14.50
14-Jan-09	Eraring	1.00	1.45	10.0	14.50
15-Jan-09	Tumut 3	0.00	1.45	10.0	0.00
16-Jan-09	Eraring	1.00	1.45	10.0	14.50
17-Jan-09	Eraring	1.00	1.45	10.0	14.50
18-Jan-09	Bayswater	0.99	1.45	10.0	14.36
19-Jan-09	Bayswater	0.99	1.45	10.0	14.36
20-Jan-09	Tumut 3	0.00	1.45	10.0	0.00
21-Jan-09	Bayswater	0.99	1.45	10.0	14.36
22-Jan-09	Bayswater	0.99	1.45	10.0	14.36
23-Jan-09	Bayswater	0.99	1.45	10.0	14.36
24-Jan-09	Bayswater	0.99	1.45	10.0	14.36
25-Jan-09	Bayswater	0.99	1.45	10.0	14.36
26-Jan-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
27-Jan-09	Bayswater	0.99	1.45	10.0	14.36
28-Jan-09	Tumut 3	0.00	1.45	10.0	0.00
29-Jan-09	Tumut 3	0.00	1.45	10.0	0.00
30-Jan-09	Tumut 3	0.00	1.45	10.0	0.00
31-Jan-09	Bayswater	0.99	1.45	10.0	14.36
1-Feb-09	Bayswater	0.99	1.45	10.0	14.36
2-Feb-09	Tumut 3	0.00	1.45	10.0	0.00
3-Feb-09	Bayswater	0.99	1.45	10.0	14.36
4-Feb-09	Bayswater	0.99	1.45	10.0	14.36
5-Feb-09	Tumut 3	0.00	1.45	10.0	0.00
6-Feb-09	Tumut 3	0.00	1.45	10.0	0.00
7-Feb-09	Bayswater	0.99	1.45	10.0	14.36
8-Feb-09	Tumut 3	0.00	1.45	10.0	0.00
9-Feb-09	Bayswater	0.99	1.45	10.0	14.36
10-Feb-09	Eraring	1.00	1.45	10.0	14.50
11-Feb-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
12-Feb-09	Eraring	1.00	1.45	10.0	14.50
13-Feb-09	Tallawarra	0.47	1.45	10.0	6.82
14-Feb-09	Bayswater	0.99	1.45	10.0	14.36
15-Feb-09	Bayswater	0.99	1.45	10.0	14.36
16-Feb-09	Tallawarra	0.47	1.45	10.0	6.82
17-Feb-09	Bayswater	0.99	1.45	10.0	14.36
18-Feb-09	Tallawarra	0.47	1.45	10.0	6.82
19-Feb-09	Tallawarra	0.47	1.45	10.0	6.82
20-Feb-09	Eraring	1.00	1.45	10.0	14.50
21-Feb-09	Bayswater	0.99	1.45	10.0	14.36
22-Feb-09	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
23-Feb-09	Bayswater	0.99	1.45	10.0	14.36
24-Feb-09	Bayswater	0.99	1.45	10.0	14.36
25-Feb-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
26-Feb-09	Tallawarra	0.47	1.45	10.0	6.82
27-Feb-09	Liddell	1.08	1.45	10.0	15.66
28-Feb-09	Bayswater	0.99	1.45	10.0	14.36
1-Mar-09	Bayswater	0.99	1.45	10.0	14.36
2-Mar-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
3-Mar-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
4-Mar-09	Bayswater	0.99	1.45	10.0	14.36
5-Mar-09	Bayswater	0.99	1.45	10.0	14.36
6-Mar-09	Bayswater	0.99	1.45	10.0	14.36
7-Mar-09	Bayswater	0.99	1.45	10.0	14.36
8-Mar-09	Vales Point B	1.00	1.45	10.0	14.50
9-Mar-09	Liddell	1.08	1.45	10.0	15.66
10-Mar-09	Bayswater	0.99	1.45	10.0	14.36
11-Mar-09	Tallawarra	0.47	1.45	10.0	6.82
12-Mar-09	Tallawarra	0.47	1.45	10.0	6.82
13-Mar-09	Liddell	1.08	1.45	10.0	15.66
14-Mar-09	Bayswater	0.99	1.45	10.0	14.36
15-Mar-09	Bayswater	0.99	1.45	10.0	14.36
16-Mar-09	Vales Point B	1.00	1.45	10.0	14.50
17-Mar-09	Liddell	1.08	1.45	10.0	15.66
18-Mar-09	Mt Piper	0.94	1.45	10.0	13.63
19-Mar-09	Uranquinty	0.74	1.45	10.0	10.73
20-Mar-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
21-Mar-09	Eraring	1.00	1.45	10.0	14.50
22-Mar-09	Eraring	1.00	1.45	10.0	14.50
23-Mar-09	Liddell	1.08	1.45	10.0	15.66
24-Mar-09	Tallawarra	0.47	1.45	10.0	6.82
25-Mar-09	Mt Piper	0.94	1.45	10.0	13.63
26-Mar-09	Tumut 3	0.00	1.45	10.0	0.00
27-Mar-09	Mt Piper	0.94	1.45	10.0	13.63
28-Mar-09	Mt Piper	0.94	1.45	10.0	13.63
29-Mar-09	Bayswater	0.99	1.45	10.0	14.36
30-Mar-09	Uranquinty	0.74	1.45	10.0	10.73
31-Mar-09	Bayswater	0.99	1.45	10.0	14.36
1-Apr-09	Uranquinty	0.74	1.45	10.0	10.73
2-Apr-09	Uranquinty	0.74	1.45	10.0	10.73
3-Apr-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
4-Apr-09	Wallerawang C	1.05	1.45	10.0	15.23
5-Apr-09	Bayswater	0.99	1.45	10.0	14.36
6-Apr-09	Uranquinty	0.74	1.45	10.0	10.73
7-Apr-09	Eraring	1.00	1.45	10.0	14.50
8-Apr-09	Wallerawang C	1.05	1.45	10.0	15.23
9-Apr-09	Tallawarra	0.47	1.45	10.0	6.82
10-Apr-09	Bayswater	0.99	1.45	10.0	14.36
11-Apr-09	Vales Point B	1.00	1.45	10.0	14.50
12-Apr-09	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
13-Apr-09	Bayswater	0.99	1.45	10.0	14.36
14-Apr-09	Liddell	1.08	1.45	10.0	15.66
15-Apr-09	Tallawarra	0.47	1.45	10.0	6.82
16-Apr-09	Tallawarra	0.47	1.45	10.0	6.82
17-Apr-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
18-Apr-09	Bayswater	0.99	1.45	10.0	14.36
19-Apr-09	Bayswater	0.99	1.45	10.0	14.36
20-Apr-09	Liddell	1.08	1.45	10.0	15.66
21-Apr-09	Wallerawang C	1.05	1.45	10.0	15.23
22-Apr-09	Wallerawang C	1.05	1.45	10.0	15.23
23-Apr-09	Liddell	1.08	1.45	10.0	15.66
24-Apr-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
25-Apr-09	Bayswater	0.99	1.45	10.0	14.36
26-Apr-09	Bayswater	0.99	1.45	10.0	14.36
27-Apr-09	Uranquinty	0.74	1.45	10.0	10.73
28-Apr-09	Uranquinty	0.74	1.45	10.0	10.73
29-Apr-09	Uranquinty	0.74	1.45	10.0	10.73
30-Apr-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
1-May-09	Wallerawang C	1.05	1.45	10.0	15.23
2-May-09	Bayswater	0.99	1.45	10.0	14.36
3-May-09	Bayswater	0.99	1.45	10.0	14.36
4-May-09	Tallawarra	0.47	1.45	10.0	6.82
5-May-09	Tallawarra	0.47	1.45	10.0	6.82
6-May-09	Tallawarra	0.47	1.45	10.0	6.82
7-May-09	Tallawarra	0.47	1.45	10.0	6.82
8-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
9-May-09	Vales Point B	1.00	1.45	10.0	14.50
10-May-09	Bayswater	0.99	1.45	10.0	14.36
11-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
12-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
13-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
14-May-09	Tallawarra	0.47	1.45	10.0	6.82
15-May-09	Wallerawang C	1.05	1.45	10.0	15.23
16-May-09	Bayswater	0.99	1.45	10.0	14.36
17-May-09	Bayswater	0.99	1.45	10.0	14.36
18-May-09	Uranquinty	0.74	1.45	10.0	10.73
19-May-09	Tallawarra	0.47	1.45	10.0	6.82
20-May-09	Vales Point B	1.00	1.45	10.0	14.50
21-May-09	Tallawarra	0.47	1.45	10.0	6.82
22-May-09	Vales Point B	1.00	1.45	10.0	14.50
23-May-09	Bayswater	0.99	1.45	10.0	14.36
24-May-09	Bayswater	0.99	1.45	10.0	14.36
25-May-09	Uranquinty	0.74	1.45	10.0	10.73
26-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
27-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
28-May-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
29-May-09	Uranquinty	0.74	1.45	10.0	10.73
30-May-09	Liddell	1.08	1.45	10.0	15.66
31-May-09	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
1-Jun-09	Uranquinty	0.74	1.45	10.0	10.73
2-Jun-09	Uranquinty	0.74	1.45	10.0	10.73
3-Jun-09	Uranquinty	0.74	1.45	10.0	10.73
4-Jun-09	Uranquinty	0.74	1.45	10.0	10.73
5-Jun-09	Vales Point B	1.00	1.45	10.0	14.50
6-Jun-09	Bayswater	0.99	1.45	10.0	14.36
7-Jun-09	Bayswater	0.99	1.45	10.0	14.36
8-Jun-09	Bayswater	0.99	1.45	10.0	14.36
9-Jun-09	Liddell	1.08	1.45	10.0	15.66
10-Jun-09	Uranquinty	0.74	1.45	10.0	10.73
11-Jun-09	Tumut 3	0.00	1.45	10.0	0.00
12-Jun-09	Vales Point B	1.00	1.45	10.0	14.50
13-Jun-09	Vales Point B	1.00	1.45	10.0	14.50
14-Jun-09	Bayswater	0.99	1.45	10.0	14.36
15-Jun-09	Bayswater	0.99	1.45	10.0	14.36
16-Jun-09	Bayswater	0.99	1.45	10.0	14.36
17-Jun-09	Bayswater	0.99	1.45	10.0	14.36
18-Jun-09	Bayswater	0.99	1.45	10.0	14.36
19-Jun-09	Bayswater	0.99	1.45	10.0	14.36
20-Jun-09	Bayswater	0.99	1.45	10.0	14.36
21-Jun-09	Bayswater	0.99	1.45	10.0	14.36
22-Jun-09	Bayswater	0.99	1.45	10.0	14.36
23-Jun-09	Bayswater	0.99	1.45	10.0	14.36
24-Jun-09	Bayswater	0.99	1.45	10.0	14.36
25-Jun-09	Bayswater	0.99	1.45	10.0	14.36
26-Jun-09	Bayswater	0.99	1.45	10.0	14.36
27-Jun-09	Bayswater	0.99	1.45	10.0	14.36
28-Jun-09	Bayswater	0.99	1.45	10.0	14.36
29-Jun-09	Bayswater	0.99	1.45	10.0	14.36
30-Jun-09	Bayswater	0.99	1.45	10.0	14.36
1-Jul-09	Bayswater	0.99	1.45	10.0	14.36
2-Jul-09	Bayswater	0.99	1.45	10.0	14.36
3-Jul-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
4-Jul-09	Bayswater	0.99	1.45	10.0	14.36
5-Jul-09	Bayswater	0.99	1.45	10.0	14.36
6-Jul-09	Tumut 3	0.00	1.45	10.0	0.00
7-Jul-09	Tumut 3	0.00	1.45	10.0	0.00
8-Jul-09	Tumut 3	0.00	1.45	10.0	0.00
9-Jul-09	Eraring	1.00	1.45	10.0	14.50
10-Jul-09	Vales Point B	1.00	1.45	10.0	14.50
11-Jul-09	Bayswater	0.99	1.45	10.0	14.36
12-Jul-09	Bayswater	0.99	1.45	10.0	14.36
13-Jul-09	Eraring	1.00	1.45	10.0	14.50
14-Jul-09	Bayswater	0.99	1.45	10.0	14.36
15-Jul-09	Tumut 3	0.00	1.45	10.0	0.00
16-Jul-09	Bayswater	0.99	1.45	10.0	14.36
17-Jul-09	Bayswater	0.99	1.45	10.0	14.36
18-Jul-09	Bayswater	0.99	1.45	10.0	14.36
19-Jul-09	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
20-Jul-09	Eraring	1.00	1.45	10.0	14.50
21-Jul-09	Bayswater	0.99	1.45	10.0	14.36
22-Jul-09	Bayswater	0.99	1.45	10.0	14.36
23-Jul-09	Bayswater	0.99	1.45	10.0	14.36
24-Jul-09	Bayswater	0.99	1.45	10.0	14.36
25-Jul-09	Bayswater	0.99	1.45	10.0	14.36
26-Jul-09	Bayswater	0.99	1.45	10.0	14.36
27-Jul-09	Bayswater	0.99	1.45	10.0	14.36
28-Jul-09	Eraring	1.00	1.45	10.0	14.50
29-Jul-09	Bayswater	0.99	1.45	10.0	14.36
30-Jul-09	Bayswater	0.99	1.45	10.0	14.36
31-Jul-09	Bayswater	0.99	1.45	10.0	14.36
1-Aug-09	Bayswater	0.99	1.45	10.0	14.36
2-Aug-09	Liddell	1.08	1.45	10.0	15.66
3-Aug-09	Eraring	1.00	1.45	10.0	14.50
4-Aug-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
5-Aug-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
6-Aug-09	Bayswater	0.99	1.45	10.0	14.36
7-Aug-09	Eraring	1.00	1.45	10.0	14.50
8-Aug-09	Bayswater	0.99	1.45	10.0	14.36
9-Aug-09	Bayswater	0.99	1.45	10.0	14.36
10-Aug-09	Tumut 3	0.00	1.45	10.0	0.00
11-Aug-09	Tumut 3	0.00	1.45	10.0	0.00
12-Aug-09	Eraring	1.00	1.45	10.0	14.50
13-Aug-09	Liddell	1.08	1.45	10.0	15.66
14-Aug-09	Bayswater	0.99	1.45	10.0	14.36
15-Aug-09	Eraring	1.00	1.45	10.0	14.50
16-Aug-09	Eraring	1.00	1.45	10.0	14.50
17-Aug-09	Liddell	1.08	1.45	10.0	15.66
18-Aug-09	Bayswater	0.99	1.45	10.0	14.36
19-Aug-09	Tallawarra	0.47	1.45	10.0	6.82
20-Aug-09	Bayswater	0.99	1.45	10.0	14.36
21-Aug-09	Bayswater	0.99	1.45	10.0	14.36
22-Aug-09	Bayswater	0.99	1.45	10.0	14.36
23-Aug-09	Bayswater	0.99	1.45	10.0	14.36
24-Aug-09	Bayswater	0.99	1.45	10.0	14.36
25-Aug-09	Bayswater	0.99	1.45	10.0	14.36
26-Aug-09	Bayswater	0.99	1.45	10.0	14.36
27-Aug-09	Tallawarra	0.47	1.45	10.0	6.82
28-Aug-09	Tumut 3	0.00	1.45	10.0	0.00
29-Aug-09	Bayswater	0.99	1.45	10.0	14.36
30-Aug-09	Bayswater	0.99	1.45	10.0	14.36
31-Aug-09	Bayswater	0.99	1.45	10.0	14.36
1-Sep-09	Wallerawang C	1.05	1.45	10.0	15.23
2-Sep-09	Bayswater	0.99	1.45	10.0	14.36
3-Sep-09	Bayswater	0.99	1.45	10.0	14.36
4-Sep-09	Mt Piper	0.94	1.45	10.0	13.63
5-Sep-09	Bayswater	0.99	1.45	10.0	14.36
6-Sep-09	Bayswater	0.99	1.45	10.0	14.36

Date	Marginal Power Plant	Emissions Factor (tCO_2-e/MWh)	Load Reduction (including losses) (MVA)	Duration (Hours)	Emissions Reduction (tCO2-e)
7-Sep-09	Mt Piper	0.94	1.45	10.0	13.63
8-Sep-09	Tallawarra	0.47	1.45	10.0	6.82
9-Sep-09	Tumut 3	0.00	1.45	10.0	0.00
10-Sep-09	Tumut 3	0.00	1.45	10.0	0.00
11-Sep-09	Bayswater	0.99	1.45	10.0	14.36
12-Sep-09	Bayswater	0.99	1.45	10.0	14.36
13-Sep-09	Liddell	1.08	1.45	10.0	15.66
14-Sep-09	Tumut 1 & 2	0.00	1.45	10.0	0.00
15-Sep-09	Tallawarra	0.47	1.45	10.0	6.82
16-Sep-09	Colongra	0.74	1.45	10.0	10.73
17-Sep-09	Vales Point B	1.00	1.45	10.0	14.50
18-Sep-09	Liddell	1.08	1.45	10.0	15.66
19-Sep-09	Bayswater	0.99	1.45	10.0	14.36
20-Sep-09	Bayswater	0.99	1.45	10.0	14.36
21-Sep-09	Eraring	1.00	1.45	10.0	14.50
22-Sep-09	Vales Point B	1.00	1.45	10.0	14.50
23-Sep-09	Liddell	1.08	1.45	10.0	15.66
24-Sep-09	Bayswater	0.99	1.45	10.0	14.36
25-Sep-09	Liddell	1.08	1.45	10.0	15.66
26-Sep-09	Bayswater	0.99	1.45	10.0	14.36
27-Sep-09	Bayswater	0.99	1.45	10.0	14.36
28-Sep-09	Uranquinty	0.74	1.45	10.0	10.73
29-Sep-09	Tallawarra	0.47	1.45	10.0	6.82
30-Sep-09	Vales Point B	1.00	1.45	10.0	14.50
				Total	3874.40

4.6 Comparison of the Estimation Methods

Table 9 shows the results of the estimation of the emission reductions achieved for each of the four projects by the estimation methods used.

Table 9. Comparison of the Results for the Two Estimation Methods

Project	Emission Reduction (tCO_2-e)	
	Average Grid Emissions Method	Modified Marginal Historical Emissions Method
ETSA Utilities Air Conditioner Direct Load Control Program	350.4	429.9
Drummoyne Demand Management Program	942.6	786.2
Binda-Bigga Demand Management Project	89.1	54.6
Castle Hill Demand Management Program	5,120.5	3,874.4

Table 9 shows that for the three projects located in New South Wales, the emissions reductions estimated by the Average Grid Emissions Method are consistently higher than those estimated by the Modified Marginal Historical Emissions Method, by margins of between 20 and 60 per cent. In contrast, for the project located in South Australia, the emissions reduction estimated by the Modified Marginal Historical Emissions Method is 20 per cent higher than the estimate by the Average Grid Emissions Method.

These results are caused by differences between the two States in the type of power plants that were on the margin during the times the energy efficiency measures in the DSM projects were operating. In New South Wales, high greenhouse intensity coal-fired power plants were on the margin for the majority of the time the energy efficiency measures were operating. In contrast, in South Australia, low greenhouse intensity gas-fired power plants were on the margin for much of the time the measures were operating. The South Australian air conditioner cycling program operated only at peak times on hot days when generation capacity was tight; consequently, more expensive, but lower greenhouse intensity gas plants were brought on to the system to meet the peaks. These results demonstrate the impact that changes in the generation mix during the day have on the quantity of emissions reductions achieved by DSM projects.

While the impact of changes in the generation mix has been demonstrated in two Australian States, the differences would be even more pronounced when comparing two countries with different generation mixes. For example, in Australia the base load generation in most States is dominated by coal-fired power plants with high greenhouse intensities and the load following plants (gas and hydro) have lower greenhouse intensities. In contrast, in France the base load generation is nuclear with essentially zero emissions, while the load following plants (gas and oil) have higher greenhouse intensities. In the case of France, the marginal emissions factor during peak times will be higher than the average emissions factor, and so the emissions reduction calculated using the marginal factor would be higher than reduction calculated using the average factor. In most Australian States, the opposite is the case.

The example calculations of emission reductions from DSM projects also demonstrate that different results that can be obtained for emissions reductions from the same project when the estimation is carried out by different methods. Methods that use marginal emissions factors will always be more accurate than methods using average emissions factors, but the methods using marginal factors require much larger quantities of detailed data.

5. CONCLUSION

Accurately calculating the GHG emissions reductions from individual DSM projects requires a methodology that focusses on the impact of energy trading on changing the generation mix in the wholesale electricity market. As the generation mix changes, so will the marginal power plant, ie the plant that would be backed off in response to a load reduction caused by a DSM measure. Since different power plants have different emissions factors, the quantity of emissions reductions achieved by a DSM measure will change over time.

Electricity markets typically operate in 48 daily half hour trading periods. Therefore an effective and accurate methodology for calculating emission reductions from DSM projects must be able to identify changes in marginal power stations over a 30 minute time period. A range of suitable methodologies is available that can track these changes over time with varying levels of accuracy. As the accuracy of the methods increases, larger quantities of electricity market data are required.

In addition to data from the electricity market, significant quantities of data are required about the DSM project for which the emissions reduction calculation is being carried out. This includes data about the load reduction achieved by the project and detailed information about the time of day, the days of the week, and the seasons during which the project DSM measures are actually operating. This latter information is often not readily available. In the example calculations in Section 4 of this report, major assumptions were required about the time periods when the DSM measures were operating.

Calculations of the GHG emissions reductions from individual DSM projects will always be estimates, the accuracy of which depends on the assumptions made about events in the electricity market and about how various DSM measures operate. Methods that use marginal emissions factors will always be more accurate than methods using average emissions factors, but the methods using marginal factors require much larger quantities of detailed data. The level of resources expended on carrying out such calculations should be appropriate to the level of accuracy required. The required accuracy level is ultimately determined by the purpose for which the emissions reduction are calculated, ie how the estimates of emissions reductions are intended to be used.

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