The impact of distributed solar generation on the wholesale electricity market

June 2013

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Final report to the Consumer Advocacy Panel
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Executive Summary

Policies designed to accelerate the deployment of renewable energy remain controversial. Policies such as feed-in tariffs and the Renewable Energy Target have been criticized for the cost burden they place on consumers, as well as the ‘regressive’ manner they are distributed across end users. However, such criticisms often ignore other mechanisms which may offset these costs. A key offset is the ‘merit order effect’, a phenomenon characterized by the reduction in wholesale spot prices as levels of renewable energy generation increase.

This project aims to further explore this effect, building on previous analysis (McConnell et al. 2013), with the objective of increasing understanding how this effect may offset costs. In order to improve the evaluation of merit order effect a more sophisticated modelling approach was required. Specifically, this includes the development of a more detailed and solar generation output model and the development and demonstration of a more complex five market region model (incorporating the impact of interconnector constraints and losses).

Using the improved dispatch model with the solar output model allowed a more detailed evaluation of the merit order effect and the impact and distributed solar generation on the NEM to be undertaken. Additional information (dispatch from individual dispatch units) allowed the impact on particular generation types (e.g. the impact on gas generation vs. the impact on brown coal generators) to be quantified.

The modelling results indicate that distributed solar generation has a disproportionate impact on black coal generators, with output falling by over 8% in the high solar installation scenario (compared with 4% and 6% for gas and brown coal respectively).

The distributed PV was also found to reduce the spot market turnover by as much as $1 billion in the high solar capacity scenario. This represents over 16% of the total market turnover in the 2011-12 financial years. The model does not capture or recreate the volatility of the spot market however, and as such it is was not possible to evaluate the extent to which PV impacts volatility. The modelling results also indicate that the spatial distribution of PV has little impact on the value of the spot price reduction.

The extent to which spot price reductions are passed through to consumer electricity prices is a function of the competitiveness of the market, and the ability of retailers to effectively manage risks associated with the market (and the risks associated with high PV generation). Should the spot price reductions pass through to consumers, the merit order effect may offset any cost associated with renewable energy support and have a moderating effect on electricity prices.
Introduction

The addition of significant levels of renewable energy capacity has been shown to markedly reduce wholesale spot prices in liberalized electricity markets. This phenomenon, known as the merit order effect, is demonstrably impacting electricity wholesale prices in Australia and abroad. Distributed rooftop solar photovoltaic (PV) systems are no exception, and will also impact the wholesale electricity spot price. This project aims to evaluate the extent to which distributed PV, installed within the Australian National Electricity Market (NEM), impacts spot prices through this ‘merit order effect’. This work build on that previously developed in “Retrospective modeling of the merit-order effect on wholesale electricity prices from distributed photovoltaic generation in the Australian National Electricity Market” (McConnell et al. 2013).

The report is organized as follows: The first section provides an overview of the merit order effect, and an overview of our previous analysis. Section 2 outlines the improved solar generation model and section 3 outlines the improved market model. In section 4, the results of the merit order analysis are summarized. Section 5 discusses the results followed by a conclusion in Section 6.
Overview

The Merit Order Effect

In liberalized electricity markets electricity generation capacity is offered into a central market, which is coordinated by a centralized market operator. The market typically operates as a uniform clearing price auction, with the market operator dispatching sufficient capacity to meet demand whilst ensuring the lowest cost combination of generation (based on the offer prices). All generators receive the price offered by the highest cost generator that is dispatched to meet the demand target. In Australia, this process happens on a five minute timescale.

Conceptually, generation capacity ranked by offer price (creating a supply curve) and is dispatched in this order (in ‘merit order’) until the demand target has been met. The last generator dispatched to meet target, sets the price received by all generators. This system is known as a “Price Based Economic Dispatch” or “Merit Order Dispatch” system. Figure 1 shows an illustrative supply curve, and the set price for meeting a particular demand.

Figure 1: Illustrative supply curve [source: Pöyry 2010]

In this dispatch system, generators typically offer capacity at or around the marginal cost of production, (a strategy that maximizes a firm’s profits). The marginal cost of production represents the cost to produce a single additional unit of electricity, and is typically dominated by fuel costs. Renewable technologies, such as wind and distributed PV, have no fuel cost, and have a negligible marginal cost of production. As such, these renewable energy sources have a significant impact on the ‘merit order’. Figure 2 illustrates the impact of solar and wind on a hypothetical supply curve.
The additional low marginal cost supply results in a lower spot price, for the same dispatch target. This merit order effect has been quantified for wind technology in various European countries (Munksgaard and Morthorst 2008, Pöyry 2010) and in for a variety of renewable generation sources in Germany (Sensfuß, Ragwitz, and Genoese 2008). The impact of high penetrations of wind in the South Australian market have also been observed (Cutler et al. 2011).

Distributed rooftop PV acts as a demand side reduction with regard to the wholesale market, rather than additional low marginal cost supply. It is currently not traded, and is visible to the market through reduce demand and a reduced dispatch target. However, the impact on the wholesale spot price is similar. Rather than adding to the supply curve, distributed PV subtracts from the demand curve. In both situations, the end result is the same: a lower marginal cost generator sets the price. The combination of generators required to meet the dispatch target results in a lower clearing price.

It is this reduction that we aim to quantify, in the broader context of policy around support for renewable energy such as feed in tariffs and target schemes. Schemes such as mandated feed in tariffs for solar have previously been criticized for the impact they have on consumer electricity prices (Nelson, Simshauser, and Kelley 2011). In particular, feed in tariffs were described as regressive: the implied taxation rate (a measure of the scheme cost relative to household income) was argued to be three times higher for low income households than those in the higher income bracket.

However, such criticisms often do not consider or include the impact such generation has on the electricity market. The merit order effect may offset some or all of the costs associated with supporting solar. The objective of this work is to evaluate to what extent this may be occurring.
Previous Work
Our previous analysis investigated the merit-order effect using a simplified solar generation model and a high level market model. The key simplifications involved:

Solar Model
- Scenarios in which PV generation was confined to the capitals of the four largest NEM regions, Brisbane (QLD), Sydney (NSW), Melbourne (VIC) and Adelaide (SA).
- Solar data from only one location at each of the city centres were used alongside ideal panel installation orientation (30° elevation, north facing).

Market Model
- Considering the national electricity market as a single market region. This is equivalent to assuming there are no capacity constraints between the different market regions’
- Ignoring inter-regional loss factors and transmission loss factors (resulting in no transmission losses between different regions of the grid).

Our assumptions were intentionally conservative. Ignoring both the capacity constraints of interconnectors and the loss factors was expected to underestimate of market impacts, with any cheap source of electricity available anywhere else on the grid. Indeed the model consistently returned lower electricity prices, underestimating the value traded through the market by as much as $2.5 billion in a year, relative to the operation of the market where transmission capacity constraints and interconnector losses have an impact on the wholesale price determination. Consequently, the value of merit order effect is also expected to be underestimated, potentially significantly. In treating the NEM as a single market, rather than an interconnected five market system, regional impacts may also have been lost.

In order to improve the evaluation of merit order effect a more sophisticated market model was developed: a model that does not require the previous simplifications. This project aims to address some of the deficiencies and simplifications used in the initial study in the following ways:

- The development of a more detailed and solar generation output model
- The development and demonstration of a more sophisticated five market region model (incorporating the impact of interconnector constraints and losses).

These improved models allow for a more detailed evaluation of the merit order effect and the impact and distributed solar generation on the NEM.
Solar Generation Model

We developed a distributed solar generation model, to reflect more realistic solar production characteristics. Specifically, we incorporated a range of locations in the modelling, and consider a range of system orientations. This allows greater geographical diversity in the model and realistic system orientations to be considered, and enable a more accurate and detailed generation time series to be modelled.

This model builds on and utilizes the basic solar model used in McConnell et al. (2013). In this section, we first analyze the current characteristics of rooftop Solar in Australia. We then outline the basic modelling process, some of the necessary restrictions to the model, and the basic model outputs are described. We then develop the different. Finally different scenarios are developed and analysed, for later use in the dispatch model.

Characteristics of Australian Solar

The characteristics of rooftop solar in Australia are used to both inform the modelling and to understand and enable the development of alternative PV distribution scenarios.
Orientation
The orientation of a mounted solar panel effect the shape and timing of power output from a solar system. For example, a west-facing panel will reach its production peak later in the afternoon than a north-facing panel. A panel elevated at 60° from the horizontal will produce more power in the winter than a panel elevated at 10° from the horizontal.

Data from the website PVoutput.org was used to obtain a sample of the overall orientation of existing solar PV systems. At the time of accessing, data was available for 2,645 systems across the NEM, distributed as shown in Table 1.

Table 1: State spread of sample of PV systems from PVoutput.org

<table>
<thead>
<tr>
<th>State</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
<th>NEM</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. systems on PVoutput.org</td>
<td>905</td>
<td>568</td>
<td>586</td>
<td>553</td>
<td>33</td>
<td>2645</td>
</tr>
<tr>
<td>Percentage Break Down</td>
<td>34%</td>
<td>21%</td>
<td>22%</td>
<td>21%</td>
<td>1%</td>
<td>100%</td>
</tr>
</tbody>
</table>

1 PVoutput.org is a website where people voluntarily upload information about their PV systems and their solar output. It is possible that the sample data from PVOutput.org is not representative of all PV systems across the NEM. This data was the best available to analyze in detail the spread of system orientations, to inform the modelling.
Some of the notable attributes include:

- 35-45% of systems were elevated at 20°-25°
- The distribution of elevations vary between the states, whereas the distribution of orientations is more uniform
- Queensland had proportionally more systems at low elevations (and less at high elevations)
Spatial Distribution

Future distributions of solar may be expected to be having some similar characteristics to current distributions. For example, distributions may be guided by correlation with population data. The distributions are analyzed in tandem with populations distribution data understand how solar is currently distributed, based on a range of metrics.

Data from the Clean Energy Regulator is used to analyze the spatial distribution. The data available includes both installed capacity and the number of systems by postcode. A snapshot of this data form of June 2012 was used as the basis of the spatial analysis. At this time, there was 646,082 small-scale solar PV systems registered in NEM states, totaling 1,441 MWp of capacity (Clean Energy Regulator 2012). The distribution is illustrated in Figure 5. South-eastern Queensland generally has the highest installed capacities across the NEM.
Figure 5: Small-scale solar PV capacity (kW) by postcode as of June 2012. Data: Clean Energy Regulator
Postcode area data is used to determine the density of solar installations (kilowatts per square kilometer). As can be expected, the greatest density of solar PV capacity is in capital cities (Figure 6). Notably, this illustrates a low geographical diversity for currently installed capacity.

Figure 6: Small-scale solar PV capacity measured by kilowatts per square kilometre ($\text{kW/km}^2$), by postcode. Data: Clean Energy Regulator, Australian Bureau of Statistics
The population in each postcode\(^2\) is used to determine the per capita solar density (watts per person). Figure 7 illustrates that the concentration of solar PV capacity per person is lower in the capital cities, relative to regional areas.

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\(^2\) As of the date of analysis, Census 2011 data was available for population by postcode
To more formally analyze the population distribution, and the breakdown between regional and urban distributions, Australian Bureau of Statistics (ABS) Urban Centre/Locality (UCL) classifications were employed\(^3\). There are 1750 Urban Centre’s and Localities across Australia, which accounts for approximately 90% of the population\(^4\). The majority of the population is located in urban locations, with 82% of the population in only 200 UCLs. Each UCL in Australia is further classified into Remoteness Area Classes, dependent on its location in the zones shown in Figure 8.

\(^3\) An urban centre is a population cluster of 1,000 or more people while a Locality is a population cluster of between 200 and 999 people.

\(^4\) The remaining 10% is classified under “Rural Balance”, “No Usual Address” and “Off-shore Areas & Migratory”.

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**Figure 8: Map of Australian Standard Geographical Classification “Remoteness Structure” as of 2006 Census (Australian Bureau of Statistics 2012)**
Figure 9 and Figure 10 illustrate distributed solar characteristics based on these Remoteness Area Classes.

As expected, the greatest amount of installed PV capacity is found in Major Cities of Australia (which includes both state capitals and larger cities such as Wollongong, Newcastle, Geelong, and Sunshine Coast). In these regions, there is an average of 66 Watts per person compared with a weighted average of 101 Watts per person within the other regions. As shown in Figure 10, there is a trend towards larger PV system sizes in more remote areas.
Modelling Distributed Solar

Basic Model
We use the same base solar model as used in McConnell et al. (2013). This model takes the following key inputs:

- The orientation of the panel, described by azimuth and zenith (elevation)
- Measured temperature data, on the same timescale as solar radiation
- Measured solar radiation data

These inputs, alongside a variety of technical specifications\(^5\) are used to outputs normalized solar generation as a time series. The normalized generation (also referred to as Instantaneous Capacity Factor, ICF) is a measure of the instantaneous power output as a proportion of the rated maximum power output (i.e kW production per kW installed). This value is scaled as required after the output is generated by the model.

In this work we model solar generation in much larger range of locations, using a more representative range of system orientations.

Distributed solar model
We model the distributed solar output by running the basic solar model for each location and for a range of different orientations. The previously mentioned key inputs are therefore required for each location to be modelled. The following briefly describes what data is used, (and how it is used in this analysis):

Solar – Global Horizontal Irradiance (GHI) solar data on an hourly timescale is a critical input for the solar generation model. We used data from the Geostationary Meteorological Satellite and other satellites (BoM 2012). This dataset contains hourly values of GHI and Direct Normal Irradiance (DNI) in a 5 x 5km grid across Australia.

Orientation – The modelled output from a solar system is highly dependent of the system orientation. The orientation characteristics used in the model are based on the PVoutput.org data, previously analyzed. A range of orientations were modelled, to obtain a solar power output representative of many different individual solar panel systems mounted at different elevations and azimuth orientations.

\(^5\) See McConnell et al. (2013) for further details and key input assumptions
For each state, 25 different orientation categories modelled, representing combinations of each the five elevation angles and five azimuth orientations (see Figure 11 for example).

![Figure 11: Distribution of the elevation/azimuth combination modelled for South Australia](image)

**Temperature** - Temperature data is required to calculate and correct for the variable solar panel efficiency, which is a function of temperature. This data is required on an hourly timescale, to reflect the variation throughout the day (rather than daily averages or maximums). The Bureau of Meteorology weather station data is used in the modelling.
Geographical Restriction

Ideally, the solar output would be modelled for all relevant geographical location, for all orientations. However, there are restrictions placed on the number of possible geographical locations to model, due to data availability. Our choice of locations is dictated by the need to obtain geographical diversity, while also ensuring the basic input data is available.

Hourly temperature data is a particularly restricting data requirement. Whilst the Bureau of Meteorology has large network of weather monitoring stations, only a subset of these has the capability to record hourly temperature data. Most are located in or near Australian towns and cities (often, for example, at airports).

The location selection was therefore largely based on the availability of suitable temperature data. Seventy seven temperature stations were available within the NEM states. This corresponded to 61 different UCL locations, as some larger UCL’s have multiple suitable temperature stations.

The 61 chosen UCLs represent 73% of the 2006 population registered in the NEM states and territories. Figure 12 illustrates the geographical distribution of the UCL locations selected. Appendix A includes a table with all locations considered in the analysis.

The temperature data, solar grid and UCL locations are not perfectly co-located. Appendix B illustrates how a UCL, the temperature station and solar grid are combined in order to model each single location. This includes the amalgamation of data in cases where multiple temperature stations exist in a single location.
Model Summary
The basic solar PV model was run over for each of the 61 selected locations, 25 times (once for each elevation/azimuth combination). The hourly outputs of each of the orientations were weighted (according to the state-based orientation distributions from PVoutput.org) to obtain a single set of outputs, per temperature station location. Figure 13 illustrates a basic flow chart of the process.

![Flowchart of solar PV output model for a given location](image)

The National Electricity Market’s Dispatch Engine is resolved every 5 minutes. As solar and temperature data was only available hourly, simple linear interpolation is used to generate 5-minute data points for use in the dispatch engine.

The overall process for obtaining the representative panel orientation dataset is illustrated in Appendix C.
Solar Model Results

Figure 14 and Figure 15 illustrate example outputs from the PV modelling for different individual UCLs.

A comparison of Morwell (Vic), Moree (NSW) and Mackay (QLD) in Figure 14 and Figure 15 demonstrates that the daily and seasonal differences in solar PV output in different locations across Australia.
The differences in seasonal output for the different UCL’s are illustrated in the monthly average capacity factors in Figure 16. The overall annual average capacity factors are also compared in Figure 17. Locations that are further north and further inland tend to have both a higher overall average output, and have less seasonal variability.

A notable aspect of the PV generation is that large cities, with higher population densities, tend to have lower overall solar power output, relative to more remote locations. When the solar PV output data analyzed in Remoteness Area Classifications a similar trend is observed.

![Figure 16: Monthly average solar PV modelling results of each of the 61 Urban Centres/Localities chosen across the NEM, coloured by five classifications based on overall five-year monthly average capacity factor.](image)

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6 The colour ranking in Figure 16 is the same as the colour ranking (by overall annual average capacity factor) in Figure 17.
Figure 17: Five-year average modelled solar capacity factor by UCL, ranked in five categories
Solar Distribution Scenarios

We tested different geographic distributions of PV deployment across the NEM. This enabled us to observe changes in the aggregate solar power output, and the resulting impact this has on the Merit Order Effect.

Future uptake scenarios of solar PV in the NEM may not necessarily precisely follow the same distribution patterns between population centre’s and remoteness areas as current deployment. However, future deployment scenarios are likely to be related to the population distribution.

The Australian Bureau of Statistics “Remoteness Structure”, was chosen as a useful the metric to vary PV capacity between geographic locations. This classification provides a useful lens to characterize the current distribution (as previously), and a convenient basis to explore alternative deployment scenarios.

Four different scenarios of solar PV distribution were prepared based on weighting the capacity in each of the 61 UCL locations relative to the others, as a function of population (2006 Census) and Remoteness Area. The four scenarios are defined by the Watts per person, relative to each of the five Remoteness Area Classes.

The four scenarios are defined and explained below:

- **UCL Even**: This scenario gives an equal weighting to the population of each of the 61 UCLs analyzed. This scenario results in a relative increase in PV capacity in major Cities.

- **Real Even**: This scenario applies different weightings to the population of each of the 61 UCLs to recreate the actual current population distribution between Remoteness Area Classes. (For example, 70.8% of the population in NEM states was in Major Cities, 20.2% in Inner Regional, 8.0% in Outer Regional, 0.7% in Remote Australia and 0.3% in Very Remote Australia. Weightings were applied such that within the 61 UCLs analyzed, this population distribution was recreated. Capacity within UCLs of the same RA Class was distributed equally by population).

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7 As the modelling is limited to the 61 UCL locations, it is not precisely representative of the actual population distribution in Australia – the 61 UCLs only cover 73% of the 2006 Census population of the NEM states.

8 Multiplying this figure by the population in each UCL gives the capacity by UCL as a proportion of the total.
- **Actual 2012**: This scenario applies weightings to recreate the actual current distribution of PV capacity between Remoteness Areas based on June 2012 installed capacity data. (For example, 61.1% of the PV capacity registered by the Clean Energy Regulator was installed in Major Cities of Australia, so weightings were applied to recreate this distribution within the 61 UCL locations).

- **Regional Skew**: Higher weightings were to the more remote locations, to develop a scenario with greater PV capacity in (typically sunnier) regional and remote areas than in Major Cities.

Figure 18 illustrates the relative proportions of capacity in the four scenarios in each of the different remoteness areas. The following map visualizes the distribution for UCL even scenario. The remaining scenarios can be view in Appendix D.
Figure 19: "UCL Even" scenario relative proportions of PV capacity by UCL
Capacity Scenarios
The Australian Energy Market Operator has published a range of forecasts of increased solar PV capacity in the NEM (AEMO 2012b). These scenarios range from approximately 3,000 to 7,500 MW by 2020, and 4,600-18,000 MW by 2030. These future forecasts are several times greater than current installed capacity (just under 1,500 MW at the time of AEMO’s publication).

Defining a specific solar capacity is not necessary for this work. Many different values of total capacity can be modelled, using the normalized outputs created for each scenario. We investigated scenarios with an up to an additional 10 GW of installed capacity. This is slightly less than the 12 GW AEMO is anticipating to be installed by 2031 (AEMO 2012b).
Scenario Comparisons

The relative weightings under the four scenarios were used to determine the overall normalized generation, for each state. This was created by applying the weightings for each UCL to normalized output modelled for each UCL, and then aggregating by state. This output forms the final input into the next stage of Merit Order Effect modelling, using the NEM market dispatch engine.

Output comparisons

Figure 21 shows the difference in overall annual average capacity factor between the four scenarios. The difference between the lowest scenario (UCL Even) and highest scenario (Regional Skew) is approximately 4%.

![Overall average capacity factor](image)

**Figure 21: NEM-wide average solar PV capacity factor for different distribution scenarios**

The differences between the distribution scenarios are greater, when considering a smaller timescale, and different NEM regions. Figure 22 shows the differences in the contribution of solar PV in Queensland (as a subset of the rest of the NEM), between the different distribution scenarios.
Figure 23, illustrates noticeable differences in NEM-wide PV output at the timescale of hours on individual days between the different distribution scenarios.

Figure 22: Daily average PV output results for Queensland in 2011, by distribution scenario. Note y-axis refers to the contribution of Queensland PV output as part of the rest of the NEM, not actual capacity factor

Figure 23: Hourly NEM-wide solar PV output results from February 11-14, 2009, by distribution (skew) scenario
Figure 24 highlights the difference in average daily solar PV output over several in the month of June. Distribution scenario 4 (Regional Skew) shows a relative high output, likely due to the greater amount of capacity installed in sunnier regional areas.

Figure 24: Daily average NEM-wide solar PV output for June 2011, by distribution (skew) scenario
Dispatch Model

As outlined earlier, key to further exploring the merit order effect is the development of a dispatch model with a greater level of fidelity. In particular, the model needs to be capable of determining the Regional Reference Price (RRP) of the five market regions, interconnector flows and interconnector losses. This new model includes:

- A dispatch algorithm that optimizes the dispatch of electricity,
- A model for the marginal loss factors, as a function of the interconnector flows and interconnector limits.
- Integration the interconnector loss model with the dispatch algorithm, to create a five region dispatch engine model

Modelling Approach

Liberalized electricity markets traditionally use ‘Economic Dispatch’ engines to determine the optimal dispatch of electricity generators to meet system load at lowest cost. The dispatch engines typically use Linear Programming or Quadratic Programming based solvers to minimize the cost of generation, whilst being constrained by technical factors to ensure reliable operation of the power system (Tiwari et al. 2008). To date, most market clearing engine solvers are Linear Programming based. The Australian Energy Market Operator (AEMO) uses the National Electricity Market Dispatch Engine (NEMDE) a linear programming optimization method to solve a 5-minute dispatch run (AEMO 2012a).

The McConnell et al. (2013) study used an simple algorithm to determine the wholesale spot price. Here we outline the basis of the new model, which utilizes the Computational Infrastructure for Operations Research (COIN-OR) linear programming solver (Lougee-Heimer 2003).

The basic principle behind a dispatch algorithm is to minimize the total cost of production, for a given dispatch period. Each generating unit offers capacity at different prices to the system operator. The operator aggregates all offers and solves the optimal dispatch solution that ensures:

- The lowest cost configuration of generation capacity is used
- Demand is met, taking into account system and transmission losses
- System is operated with in physical and technical limits or constraints

These limits and constraints maybe related to the transmission system, inter-regional capacity limits, or generator constraints. We use historic demand and offers, and a subset of the
constraints to develop, such a dispatch model. Appendix E outlines the full formulation of the dispatch model.

Figure 25 illustrates how the linear dispatch engine is used in conjunction with the relevant data to model the electricity market over a time series. Different data and constraint information is available over different time periods. The key data used is reference in Appendix F.

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**Figure 25: Dispatch algorithm flowchart**
Model Performance & Statistics

Basic Outputs
The key output is wholesale spot prices, at a regional level. Figure 26 and Figure 27 below illustrate the two separate examples of the simulated regional reference price compared to the actual regional reference price. This is essential information to further the analysis into the impact of distributed solar generation on the wholesale electricity price, and enable a more detailed evaluation of the merit order effect.

![Figure 26: Modelled Price vs Actual Price (QLD 2 June 2011)](image1)
![Figure 27: Modelled Price vs Actual Price (NSW, 2 March 2011)](image2)

Statistics
As can be seen in figures Figure 26 and Figure 27, the dispatch model does not perfectly replicate the actual wholesale spot price results. In fact, the model systematically underestimates actual prices.

Table 2: Mean Absolute Error of modelled values

<table>
<thead>
<tr>
<th>Region</th>
<th>MAE</th>
<th>MSD</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>$15.41</td>
<td>-$15.41</td>
</tr>
<tr>
<td>VIC</td>
<td>$10.89</td>
<td>-$10.89</td>
</tr>
<tr>
<td>QLD</td>
<td>$9.05</td>
<td>-$9.05</td>
</tr>
<tr>
<td>SA</td>
<td>$12.58</td>
<td>-$12.58</td>
</tr>
<tr>
<td>TAS</td>
<td>$11.79</td>
<td>-$11.79</td>
</tr>
</tbody>
</table>

Table 2 shows the Mean Absolute Error (MAE) of the modelled values for all NEM regions. The magnitude Mean Signed Difference (MSD) was found to be identical to the MAE. This indicates that not only does the model underestimated prices in general, it always underestimates prices (by approximately $10-$15 per MWh). This is a great underestimate than in the original work.
Further, the model does not capture scarcity events or other extreme high price events. Figure 28 shows the price duration curve for both actual and modelled prices in NSW in 2011. The plot indicates that the model does not replicated high price events, and is not suitable for assessing the impact solar has on volatility in the market.

There are a variety of reasons why this may be the case. Whilst our model does incorporate some additional constraints (e.g. interconnector constraints) it does not include the full range of dynamic constraints that are used in the actual NEM dispatch engine. In particular, additional network constraints (intra-regional), ramp rate constraints and other security based constraints are likely to have a considerable impact on the prices.

**Addition Outputs**
The dispatch optimization also yields additional information (information the original model could not capture or determine). Specifically, this includes detailed generator outputs and interconnector flows.

This information assists this analysis, allowing additional impacts (outside the wholesale spot market) to be quantified. This includes fuel savings made, and emissions avoided (due to solar displacing existing generation). Figure 29 and Figure 30 illustrate the dispatch information determined by the model for two different days.
Figure 29: Dispatch by region and fuel type (July 2011)
Figure 30: Dispatch by region and fuel type (December 2011)
Merit Order Effect Analysis

Introduction

We analyze the merit order effect by first modelling the impact of PV on system demand, and then simulating the market spot prices with the modified demand profile.

The ‘modified demand’ was created using the solar model and a hypothetical installed capacity value. The hypothetical value, representing a hypothetical capacity of PV installed NEM-wide, is multiplied by the instantaneous capacity factor values from the solar model (which incorporate a spatial distribution). This enables the solar generation in each state to be determined for each 5 minute dispatch interval. The modified demand was calculated by subtracting this value from the actual demand, as the solar generation was assumed to act as a demand side reduction. Scenarios were considered with 2, 4, 6, 8 and 10 GW of additional solar installed in the NEM. This is slightly less than the 12 GW AEMO is anticipating to be installed by 2031 (AEMO 2012b).

The modified demand profiles were used in the market model to determine the impact of solar on wholesale spot prices. This was performed by comparing the modelled price for each solar scenario and the modelled baseline price (modelled price with no installed solar). As the model did not perfectly replicate the spot market outcome, it is necessary to compare the modelled values with baseline values for consistency.

The “Real even” spatial distribution was the main PV spatial scenario considered in the analysis. Other spatial distributions were compared against this scenario.

Results: Volume

Distributed PV can generate a substantial output of electricity during daylight periods. At large installation capacities, this can have a considerable impact on the volumes of electricity required from the existing generators. The following figures illustrate the impact distributed PV has on the dispatch of electricity, based on the output of the dispatch model.

Figure 31 shows the solar output and the dispatch from the scheduled generators on a typical summer day, with 10 GW of solar installed. Figure 32 illustrates the same outputs for a typical winter’s day.
Figure 31: Dispatch by region and fuel type, including solar generation output, for 10 GW of solar capacity in the NEM (Jan 14 2011)
Figure 32: Dispatch by region and fuel type, including solar generation output, for 10 GW of solar capacity in the NEM (Jul 6 2011)
Figure 33 and Figure 34 illustrate how the output for different fuel sources changes with different solar installations for NSW over the course of the year. Figure 35 shows the annual output (sent out basis) of different generation types across the NEM, under different solar scenarios. Figure 36 and Figure 37 illustrate how the annual output of different fuel types changes under different installed solar capacity scenarios.
Figure 35: Annual output of different fuel types under different solar installation scenarios.

Figure 36: Change in output by fuel type.

Figure 37: Change in output (%).

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Results: Price and Value

The modified demand profile resulting from distributed PV also changes the dispatch price. At large installation capacities, the price impact can be considerable, particularly during mid day periods in summer. The reduction in price can have a considerable impact on the overall traded value of electricity through the market over the course of a year. The following figures illustrate the impact distributed PV has on the dispatch price of electricity, based on the output of the dispatch model.

Figure 39 and Figure 38 illustrate the typical impact on wholesale spot prices on a summer and winter day, for different solar installations. The summer wholesale spot price reduction is typically larger in magnitude and duration, due to the great coincidence of high demand and solar production in summer.
Figure 40 shows the annual value of this wholesale spot price reduction for each of the NEM jurisdictions with different solar installations. For 10 GW of installation, the value is almost $1 Billion dollars. This represents a substantial fraction of annual turnover in 2011/12 of $6 billion (Australian Energy Regulator 2012).

The value in NSW can be expected to be higher, due to the higher volume of electricity sales in this region. Victoria and Queensland have similar volumes of electricity sales. The difference between the two may be due to the prevalence of low cost generation (Brown coal) in Victoria, and the relatively greater solar resource in Queensland.
Figure 41 shows the reduction in the volume weighted wholesale spot price each of the NEM jurisdictions with different solar installations. The significant reduction in Tasmania may be due to the relatively small number of generators in Tasmania (and the corresponding ‘steep’ local merit curve).

![Graph showing reduction in volume weighted spot price](image)

**Figure 41: Annual Reduction in volume weighted price (2011)**
Results: Spatial Distribution

The spatial distribution has remarkably little effect on the merit order effect. In particular, the ‘UCL Even’, ‘Real Even’ and ‘Actual 2012’ scenarios were virtually indistinguishable. There was a slight increase in the merit order value (and the reduction in wholesale prices) for the ‘regional skew’ scenario. This is likely due to the increased solar production in this scenario, due to a higher proportion of capacity being located in regional locations with greater solar resource. Figure 42 shows the value of the wholesale price reductions in Queensland under different spatial distributions of PV.

![Figure 42: Impact of Spatial Distribution on Merit Order Value, Queensland (2011)](image)
Discussion

Results
The results suggest that distributed PV can have a moderating effect on the wholesale electricity price, and can reduce the overall value of spot price transactions considerably. The results are also broadly consistent with the previous analysis. Table 3 compares the results of this analysis with the previous work (both absolute value, and percentage of actual market turnover).

Table 3: Comparison of results

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market turnover</td>
<td>9.6</td>
<td>7.4</td>
<td>6</td>
</tr>
<tr>
<td>Prev. analysis</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Value</td>
<td>$1,073.00</td>
<td>$520.00</td>
<td>-</td>
</tr>
<tr>
<td>Percent</td>
<td>11.18%</td>
<td>7.03%</td>
<td>-</td>
</tr>
<tr>
<td>Cur. analysis</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Value</td>
<td>$1,025.98</td>
<td>$497.19</td>
<td>$363.37</td>
</tr>
<tr>
<td>Percent</td>
<td>10.69%</td>
<td>6.72%</td>
<td>6.06%</td>
</tr>
</tbody>
</table>

This current analysis returned smaller merit order savings than the previous analysis. This may be due to a combination of factors, including the impact of modelling distributed solar, and the fact the new dispatch model underestimates wholesale prices more than the previous model. The relatively smaller values for 2011 is reflective of the lower market turnover, resulting from lower demand and changing market dynamics, (which in turn, is in part due to solar).

The analysis also suggests that whilst all existing generators are effect by increasing levels of distributed PV, black coal generators are hit hardest. Black coal is disproportionately affected, with a great loss in market share. All fossil generators are burdened by both reduced wholesale prices and reduced volumes, manifesting as reduced revenues.

Limitations
The model uses a cetaris paribus approach, assuming the bidding behavior does not change with increased solar penetration. This is a weakness of the analysis, as market dynamics may be expected to adapt to the impact of a large penetration of renewable generation and the merit order effect. Some argue that generators will recover revenues in periods with lower solar generation. Rathmann (2007) argues that in competitive wholesale markets, there is limited ability to do this without collusion, or abusing market power.
Impact on Retail Prices

The extent to which electricity price might flow through to retail prices is subject to some debate. The relationship between the spot price and what consumers pay is not at all straightforward. Whilst some have argued that prices reductions will flow through to consumer and lower electricity prices (Rathmann 2007), others argue that the oligopolistic behaviour which prevails in electricity markets will erode the merit order effect and prevent its full pass through to consumers.

According to Sensfuß, Ragwitz, and Genoese (2008), the competitiveness of the electricity supply system determines how much the savings created on the wholesale market are passed on to consumers. Traber and Kemfert (2009) analyzed the effects of the Feed-in Tariff on the German market with assumptions of oligopolistic competition (“Cournot model”). This analysis based on the impact of a FiT, not the actual impact of the Merit Order Effect, but the same principles may well apply to any savings in generation cost that flow from PV solar and its impact on the spot market. Traber and Kemfert suggest that participants will increase the margin (mark up, or price-cost margin), though the profits of the participants still decrease: “the induced [margin] increase does not compensate for the producer price decrease”.

Traber (2009) found that while the FiT decrease the prices received by producers by 8%, the consumer price was increased by 3%. The study concluded that “market power shifts the burden of the FiT from the producers to the consumers, counteracting a theoretically possible price reduction on the consumer side under perfect competition”. The study also found that external regions (i.e. regions not paying for the feed-in tariff) benefit from the merit order effect in an interconnected system. This interaction may be expected to occur in Australia between states, with different states having different feed in tariff or support policies.

The question of whether wholesale movements are reflected in retail prices is further complicated by the legitimate role of hedging risks in the wholesale spot market. The change in risk and volatility with the introduction of renewables and changing market demand is an important consideration. However, recent market modelling in Australia suggests that distributed generation actually reduces volatility in the market (William E. et al. 2012). It is not clear that renewables will necessarily increase risk and volatility in the wholesale market, and the hedging costs will increase.
Long Term Considerations
The manner in which the merit order effect would impact the long term functioning of the National Electricity Market could also be investigated. The long term effects on the system will have implications for the operation and development of the grid, generation mix and overall system reliability. In Germany, some argue that marginal cost based markets are not appropriate for wind and PV dominated systems (Agora Energiewende 2013). Others argue that our current market design is not problematic, so long as we are prepared to increase the market price cap (Riesz 2012). This may be necessary to create the right signals to encourage construction of new capacity and deliver new investment in large scale energy projects (renewable or otherwise).
Conclusion

A solar photovoltaic (PV) power output model was developed that can generate an instantaneous capacity factor for a large number of locations. This model has been applied to 61 towns and cities across Australia’s National Electricity Market (NEM), where temperature and insolation data is available, using hourly data.

Four spatial scenarios were created to understand the effect of different geographical distributions of solar PV deployment in the NEM. A key area of investigation was exploring the difference between deployments primarily in large capital cities, and deployment spread widely across regional Australia. The Merit Order Effect from each of these four scenarios was then quantified, to determine how geographical distribution of Solar PV affects the wholesale market price of electricity.

To achieve this, an economic dispatch model was developed using linear programming techniques. The dispatch model was able to resolve market prices at a regional level, taking into account interconnector losses and interconnector constraints. The improved model can also determine the dispatch of electricity from individual dispatch units.

Using the more sophisticated dispatch model, with the solar output model, a more detailed evaluation of the merit order effect and the impact and distributed solar generation on the NEM was undertaken. Additional information (dispatch from individual dispatch units) allowed the impact on particular generation types (e.g. the impact gas generation vs. the impact on brown coal generators) to be quantified.

The modelling results indicate that distributed solar generation has a disproportionate impact on black coal generators, with output falling by over 8% in the high solar installation scenario (compared with 4% and 6% for gas and brown coal respectively). The distributed PV was also found to reduce the spot market turnover by as much as $1 billion in the high solar capacity scenario. This represents over 16% of the total market turnover in the 2011-12 financial year. The modelling results also indicate that the spatial distribution of PV has little impact on the value of the spot price reduction.

The extent to which these spot price reductions is passed through to consumer electricity prices is a function of the competitiveness of the market, and the ability of retailers to effectively manage risks associated with the market (and the risks associated with high PV generation). Should the spot price reductions pass through to consumers, the merit order effect may offset any cost associated with renewable energy support and have a moderating effect on electricity prices.
References


Riesz, Jenny. 2012. “100% Renewables: Exploring System Adequacy Management in the NEM”. AECOM.


Appendix A: Urban Centres/Localities chosen for solar PV analysis

<table>
<thead>
<tr>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brisbane</td>
<td>Sydney</td>
<td>Melbourne</td>
</tr>
<tr>
<td>Bundaberg</td>
<td>Canberra-Queanbeyan</td>
<td>Geelong</td>
</tr>
<tr>
<td>Cairns</td>
<td>Wollongong</td>
<td>Bairnsdale</td>
</tr>
<tr>
<td>Charleville</td>
<td>Albury-Wodonga</td>
<td>Ballarat</td>
</tr>
<tr>
<td>Cooktown</td>
<td>Armidale</td>
<td>Bendigo</td>
</tr>
<tr>
<td>Dalby</td>
<td>Bourke</td>
<td>Dinner Plain (L)</td>
</tr>
<tr>
<td>Emerald</td>
<td>Broken Hill</td>
<td>Mildura</td>
</tr>
<tr>
<td>Gatton</td>
<td>Central Coast</td>
<td>Morwell</td>
</tr>
<tr>
<td>Georgetown (L)</td>
<td>Cobar</td>
<td>Shepparton-Mooroopna</td>
</tr>
<tr>
<td>Gladstone</td>
<td>Coffs Harbour</td>
<td>Warrnambool</td>
</tr>
<tr>
<td>Gold Coast-Tweed Heads</td>
<td>Cooma</td>
<td></td>
</tr>
<tr>
<td>Hughenden</td>
<td>Coonabarabran</td>
<td>TAS</td>
</tr>
<tr>
<td>Longreach</td>
<td>Deniliquinn</td>
<td>Hobart</td>
</tr>
<tr>
<td>Mackay</td>
<td>Dubbo</td>
<td>Launceston</td>
</tr>
<tr>
<td>Rockhampton</td>
<td>Goulburn</td>
<td></td>
</tr>
<tr>
<td>Roma</td>
<td>Gunnedah</td>
<td>SA</td>
</tr>
<tr>
<td>St George</td>
<td>Lismore</td>
<td>Adelaide</td>
</tr>
<tr>
<td>Sunshine Coast</td>
<td>Moree</td>
<td>Ceduna</td>
</tr>
<tr>
<td>Townsville-Thuringowa</td>
<td>Newcastle</td>
<td>Snowtown (L)</td>
</tr>
<tr>
<td>Townsville-Thuringowa</td>
<td>Newcastle</td>
<td>Whyalla</td>
</tr>
</tbody>
</table>
Appendix B: Treatment of temperature stations, solar grid location and UCL locations

For each temperature station, the corresponding solar grid location was chosen based on matching latitude and longitude.

![Diagram showing temperature station and solar grid location](image)

**Figure 43:** Example diagram of selection of a solar data grid location for a UCL, based on the temperature station location

Most urban centres / localities only have a single temperature station available from the BoM. Some larger cities, particularly the state capitals and larger regional cities such as Geelong and Wollongong, have multiple temperature stations with hourly temperature data available distributed across the geographical spread of the city.

In cases with multiple temperature stations, each station was modelled, with their own corresponding solar grid (as in Error! Reference source not found.). This improves the representation of the data by increasing geographical diversity, rather than relying on a single temperature station and solar grid location.
For these amalgamated locations, the outputs were a simple un-weighted arithmetic average was used. The process is outlined in Figure 45.

**Figure 44:** Example schematic of several temperature stations and corresponding solar grid in the same large UCL

**Figure 45:** Process for averaging several temperature station datasets in the same UCL
Appendix C: Overall process for obtaining representative panel orientation dataset

**Figure 46:** Process for modelling and applying weighted average to 25 different panel orientation scenarios, followed by interpolation from hourly to 5-minute data.
Appendix D: Spatial Distribution Scenarios

Figure 47: "Real Even" scenario relative proportions of PV capacity by UCL
Figure 48: "Actual 2012" scenario relative proportions of PV capacity by UCL
Figure 49: "Regional Skew" scenario relative proportions of PV capacity by UCL
Appendix E: Dispatch Model

The Basic Optimization Process
The primary objective of an economic dispatch engine is to minimize the total cost of dispatch (electricity supply). To perform least cost optimization using linear programming requires:

- Isolation of the key ‘decision variables’: variables to be optimized.
- Construction of an ‘objective function’: constructed from the decision variables for the solver to minimize.
- Formulation of ‘constraint equations’: represent constraints relevant to the problem and are expressed in terms of decision variables.

For an economic dispatch problem, the key decision variables are the electrical outputs of the dispatch units and the interconnector flows, and the objective function is a function representing the total cost of dispatch for a 5 minute dispatch interval. There are many constraints in an economic dispatch problem which can include both either equalities or inequalities.

Dispatch unit decision variables
Each generator in the NEM offers electricity capacity in to the market at an offer price. A power generator facility is (usually) comprised of a series of dispatch units, and the operator of the facility has the ability to put forward ten different offers for each dispatch unit. Each offer includes a price and availability for each of the ten offer bands (these are also referred to as ‘band availability’ and ‘price band’). Whilst an operator can put forward ten different band availabilities and price bands, often bands have 0MW available (in effect reducing the number of bands).

Each of the dispatch units’ ten bands represents a different decision variable to be optimized in the solver, represented as:

\[ x_{du_i} = \text{Decision Variable for band } i \text{ of Dispatch Unit } du \text{ (MW)} \]
The Objective Function

The price of each band is the coefficient used in the objective function (cost function). The band price multiplied by the band variable \( x_{du_i} \) summed over all bands within all dispatch units is used to create the objective function. This is represented by:

\[
\text{Eq. 1}
\]

\[
\min \sum_{du,i} PB_{du_i} \times x_{du_i}
\]

Where:

- \( PB_{du_i} \) = Price of band \( i \) of Dispatch Unit \( du \) ($/MW)

Dispatch Unit Inequality Constraints

The first and simple set of constraints is limiting the dispatch unit decision variables to the amount offered (i.e. the band availability). This band availability can vary on a 5 minute timescale. Mathematically, this is represented as:

\[
\text{Eq. 2}
\]

\[
0 \leq x_{du_i} \leq BA_{du_{i\text{max}}}
\]

Where:

- \( BA_{i\text{max}} \) = Maximum availability of band \( i \) of Dispatch Unit \( du \) (MW)

Dispatch Target Equality Constraints (simple)

An important constraint is the equality constraint relating to the dispatch target. This constraint ensures that the amount of electricity dispatched is sufficient to meet demand, taking into account intra-regional losses.

Intra-regional losses are losses that occur from the point of generation to the regional reference node (RRN) of a particular region. They are pre-determined as a single static loss factor and applied at each connection point for a financial year (AEMO 2012d). These loss factors are published annually which can be used to determine the proportion of electricity dispatched that contributes to meeting the demand at the regional reference node (AEMO 2011). For example, a loss factor of 0.98 implies 2% of electricity is dispatched is lost in intra-regional transmission. The loss factors are typically greater than 0.95. The total amount of electricity dispatched that contributes to demand is represented as the sum of loss factors times the decision variable over all bands and all dispatch units:
Where:

\[ LF_{du} = \text{Loss factor for Dispatch Unit } du \ [\cdot] \]

Each individual dispatch unit has a loss factor for a given financial year (AEMO 2011). Each band variable within a dispatch unit has the same loss factor applied to it. This expression can be used in conjunction with a demand target to create an equality constraint, (which ensures the optimization actually results in the dispatch of sufficient electricity supply):

\[ \sum_{du,i} LF_{du} \times x_{dui} \]

Eq. 4

\[ \sum_{du \in du, r} LF_{du} \times x_{dui} = D_r \]

Where:

\[ D_r = \text{Demand in region } r \ (MW) \]

\[ du_r = \text{Dispatch units in region } r \]

This simple equality constraint allows a simple economic dispatch problem to be solved, which doesn’t include the inter-regional constraints and losses. Setting the dispatch target to a national demand would result in a similar model to the previous work. Setting the dispatch target to regional targets (and summing the dispatch units for each region individually) would result in a model that represents five regional markets no interconnection.
Interconnection and Interconnector Losses

Interconnection in the NEM:
There are six interconnections between the five NEM regions, illustrated in Figure 50, below. There interconnectors are usually referred to as if they were single transmission lines connecting the regions, as depicted in the figure.

![Interconnection in the National Electricity Market](source:AEMO 2010)

In reality, a ‘single’ interconnector may actually be several lines (each with varying capacity) linking different generation sources and load centre’s (Productivity Commission 2012). However, to allow a simple and effective model to be used for the dispatch process, ‘notional’ (rather than physical) interconnectors are considered. ‘Notional interconnectors’ provide a simple radial link representation of all the individual transmission lines that form the physical interconnection between adjacent regional reference nodes. (AEMO 2012d). The notional interconnector allows a single ‘average’ loss factor to be used at the region boundary, rather than one for each transmission line (Loh 2009). Figure 51 and Figure 52 conceptually illustrate the physical interconnection and notional interconnection, used in the dispatch process.
*RRN represents the Regional Reference Node, L represents load and G represents generators [source: Productivity Commission 2012]

A notional (not physical) representation of the regions of the NEM is provided in Figure 53.

Figure 51: Physical interconnection between regions  
Figure 52: Notional interconnection between regions

Figure 53: Notional representation of the regions of the NEM
This notional flow through the interconnectors represents another decision variable to be optimized by the solver. The notional flow is the flow through a notional interconnector at the boundary between two regions. The loss calculations are based on this notional flow.

The total capacity of the interconnectors can be identified. However, in the operation of the system the capacity of the actual notional interconnector may not be a limiting factor. For example, the capacity of the ‘wires across the border’ is rarely the limiting factor for transfers between NSW and VIC, and as such the interconnectors do not have single capacity (Productivity Commission 2012) Table 4 illustrates the capacities and observed flows of the interconnectors in the NEM.

Table 4: Interconnector capacity in the National Electricity Market [source: Productivity Commission 2012]

<table>
<thead>
<tr>
<th>Interconnector</th>
<th>Direction</th>
<th>Capacity</th>
<th>Peak Observed Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>QNI</td>
<td>QLD → NSW</td>
<td>1078</td>
<td>1060</td>
</tr>
<tr>
<td></td>
<td>NSW → QLD</td>
<td>700</td>
<td>20</td>
</tr>
<tr>
<td>Directlink (Teranorra)</td>
<td></td>
<td>200</td>
<td>207</td>
</tr>
<tr>
<td>VIC-NSW</td>
<td>NSW → VIC</td>
<td>undefined</td>
<td>1575</td>
</tr>
<tr>
<td></td>
<td>VIC → NSW</td>
<td>undefined</td>
<td>489</td>
</tr>
<tr>
<td>Basslink</td>
<td>TAS → VIC</td>
<td>600</td>
<td>594</td>
</tr>
<tr>
<td></td>
<td>VIC → TAS</td>
<td>480</td>
<td>416</td>
</tr>
<tr>
<td>Heywood</td>
<td>VIC ↔ SA</td>
<td>460</td>
<td>460</td>
</tr>
<tr>
<td>Murraylink</td>
<td></td>
<td>220</td>
<td>213</td>
</tr>
</tbody>
</table>

**Marginal Loss Factors**

Inter-regional losses are also calculated with loss factors. However, due to the large variability of flows between regions, a single static loss factor is not appropriate to apply between RRNs, as is done with the intra-regional losses, described above (AEMO 2012d). For interregional loss factors, an equation is derived to allow the marginal loss factor (MLF) to be calculated. The marginal loss factor represents the appropriate loss factor to be applied to an additional unit of energy transmitted through a transmission line. These marginal loss factors are calculated for each dispatch interval using a number of parameters that have a significant impact on inter-regional losses (AEMO 2012d).

The marginal loss factors can be used to determine the spot price at a given RRN (assuming the marginal generator is in another region). It is also used to determine the losses, which is important for the optimization process.
**Inter-regional Loss Factor Equations**

The loss factor equations (referred to as inter-regional loss factor equations) are a function of the total demand in each region and the power flowing through the interconnector. The loss factor equations take the form (AEMO 2011):

\[
MLF_t = a_t + b_t f_t + c_{t0} D_0 + \ldots + c_{tn} D_n
\]

Where:
- \(MLF_t\) = inter-regional marginal loss factor as function of flow
- \(a_t\) = constant for interconnector \(t\) [-]
- \(b_t\) = transfer coefficient for interconnector \(t\) [-]
- \(f_t\) = notional flow through interconnector \(t\)
- \(c_{t0}\) = coefficient for demand in region \(i\) for interconnector \(t\) [-]
- \(D_i\) = Demand in region \(i\)

Figure 54 illustrates the marginal loss factor for the NSW-VIC interconnector as a function of notional link flow at different times (and different network conditions).

![Figure 54: MLF as a function of notional flow, for NSW-VIC interconnector at different times (and network conditions)](image-url)
Inter-regional losses

Integration of the (interregional loss factor – 1) is used to determine the average losses on each notional interconnector (AEMO 2012d):

\[ \text{Inter-Regional Losses}_t = \int MLF_t - 1 \, df_t \]

Figure 55 below illustrates the losses though the NSW-VIC interconnector as a function of notional link flow at different times (and different network conditions). The loss function is different for each dispatch interval (since each dispatch interval has different demand targets).

![Figure 55: Losses as a function of notional flow, for the NSW-VIC interconnector at different times (and network conditions)](image)

The losses are therefore non-linear with respect to the notional flow through the interconnector (the losses are quadratic, proportional to \( f_t^2 \), as shown in figure Figure 55). As such, the integration of marginal loss factors into the linear solver is not straightforward or simple. There are several different approaches to deal with the quadratic nature of the losses (dos Santos and Diniz 2011).
A static piecewise linear approximation for transmission losses was used to develop this dispatch model. Each interconnector was discretized into smaller elements of length $\Delta f_t$, to create interconnector variables:

$$x_{i\text{c}_i} = \text{Decision variable for element } i \text{ of interconnector } i\text{c}$$

As with the $x_{du}$ decision variables, simple inequality constraints can be constructed, based on the $\Delta f_t$, (the length of each element).

Eq. 7

$$0 \leq x_{i\text{c}_i} \leq \Delta f_t,$$

Where:

$\Delta f_t = \text{interconnector element length}$

Importantly, by creating a series of smaller elements, a linear approximation of the losses for each element can be made (by evaluating the marginal loss factor for the flow each element). Thus the loss, expressed as function of an interconnector can be expressed as:

Eq. 8

$$\text{loss}_{i\text{c}_i} = [\text{MLF}_{i\text{c}_i} - 1]x_{i\text{c}_i}$$

Where:

$\text{loss}_{i\text{c}_i} = \text{loss in element } i \text{ of interconnector } i\text{c} \text{ due to flow } x_{i\text{c}_i}$

$\text{MLF}_{i\text{c}_i} = \text{marginal loss factor evaluated for element } i \text{ in interconnector } i\text{c}$
Figure 56 below illustrates the (MLF - 1) for discretized elements of the NSW-VIC interconnector (at a particular network condition), with an element length is 200MW (for clarity). As an example, as network flow increases from 800MW to 1000MW, the losses for this element would be approximately 9%.

These inter-regional losses must be then separated into the amount belonging to each region that the interconnector is attached to. This can be determined using the annual published proportioning factors (AEMO 2011).

Eq. 9

\[
\begin{align*}
\text{loss}_{a_{i_{c_i}}} &= P_a[MLF_{i_{c_i}} - 1]x_{i_{c_i}} \\
\text{loss}_{b_{i_{c_i}}} &= (1 - P_a)[MLF_{i_{c_i}} - 1]x_{i_{c_i}}
\end{align*}
\]

Where:

- \( \text{loss}_{a_{i_{c_i}}} \) = loss in region a
- \( \text{loss}_{b_{i_{c_i}}} \) = loss in region b
- \( P_a \) = proportioning factor, applied to region a
Five Market Dispatch Model

The interconnection variables and constraints can be integrated with the basic market model to create a five market dispatch model with interconnection. Using the notional link flows and the regional proportion losses, the simple equality (Eq. 4, pg 62) constraint can be re-written to:

\[
\sum_{du \in du_r, l} (LF_{du} \times x_{du_l}) + \sum_{ic \in ic_r, l} x_{ic_l} + \sum_{ic \in ic_r, l} P_{ic_r} [MLF_{ic_l} - 1] x_{ic_l} = D_r
\]

Where:

- \( ic_r \) = interconnectors in region \( r \)
- \( P_{ic_r} \) = proportion factor for interconnector \( ic \) applied to region \( r \)

For a given market region, this mathematical expression can be more simply represented as:

\[
\sum \text{Generation} + \sum \text{Interconnector flows} + \sum \text{Interconnector Losses} = \text{Demand}
\]

The full problem description (incorporating previous the previous equations) is presented over page. This market model successfully optimizes the economic dispatch problem, incorporating the inter-regional constraints and marginal loss factors. The model returns the optimal dispatch (for each dispatch unit), and the marginal generator and both the interconnector flow the marginal loss factor (for each interconnector) for each 5 dispatch interval. This information, in conjunction with the static intra-regional loss factors, can be used together to determine the RRP for reach RRN, for the 5 minute interval.
Minimize:

\[ \sum_{du, l} P B_{du, l} \times x_{du, l} \]

Subject to:

\[ \begin{aligned}
0 & \leq x_{du, l} \leq BA_{du, l, \text{max}} \\
\vdots & \\
0 & \leq x_{du, l} \leq BA_{du, l, \text{max}}
\end{aligned} \]

\[ \begin{aligned}
0 & \leq x_{ic, l} \leq \Delta f_t \\
\vdots & \\
0 & \leq x_{ic, l} \leq \Delta f_t
\end{aligned} \]

\[ \begin{aligned}
\left\{ \sum_{du \in du_r, l} (L F_{du} \times x_{du, l}) + \sum_{ic \in ic_r, l} x_{ic, l} + \sum_{ic \in ic_r, l} P_{icr} [MLF_{ic_r} - 1] x_{ic} \right\} = D_r
\end{aligned} \]

for all regions, \( r \)

- \( x_{du, l} \) = Decision variable for band \( i \) of Dispatch Unit \( du \) (MW)
- \( x_{ic, l} \) = Decision variable for element \( i \) of interconnector \( ic \)
- \( BA_{du, l, \text{max}} \) = Maximum availability of band \( i \) of Dispatch Unit \( du \) (MW)
- \( PB_{du, l} \) = Price of band \( i \) of Dispatch Unit \( du \) ($/MW)
- \( LF_{du} \) = Loss factor for Dispatch Unit \( du \) [-]
- \( \Delta f_t \) = interconnector element length
- \( MLF_{ic} \) = marginal loss factor evaluated for element \( i \) in interconnector \( ic \)
- \( P_{icr} \) = proportion factor for interconnector \( ic \) applied to region \( r \)
- \( D_r \) = Demand in region \( r \) (MW)
- \( ic_r \) = interconnectors in region \( r \)
- \( du_r \) = Dispatch units in region \( r \)
Appendix F: Data

The economic dispatch problem as described (in Appendix C) requires a substantial amount of data, for even a 5 minute dispatch interval. As the project aims to analyze the merit order effect over several years, a relational database has been developed to manage the data. This data is retrieve as necessary, as illustrated in the flow chart above.

The key data used by the dispatch engine is detailed in the following, with the relevant references:

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offer Data: price band and band availability data</td>
<td>(AEMO 2012c)</td>
</tr>
<tr>
<td>Regional Price and Demand (5 min)</td>
<td>(AEMO 2012c)</td>
</tr>
<tr>
<td>Inter-regional Loss-Factor Equation coefficients</td>
<td>(AEMO 2011)</td>
</tr>
<tr>
<td>Proportioning Factors</td>
<td>(AEMO 2011)</td>
</tr>
<tr>
<td>Static Intra-regional Loss Factors</td>
<td>(AEMO 2011)</td>
</tr>
</tbody>
</table>

Appendix E illustrates the schema of the database used to store and manage the data used in the dispatch engine.
Appendix G: Database Schema
Appendix H: Dispatch with Solar Generation

Figure 57: Dispatch by region and fuel type, with 5 GW solar distributed across the NEM
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Title:
Impact of distributed solar generation on the wholesale electricity market

Date:
2013-06-08

Citation:

Persistent Link:
http://hdl.handle.net/11343/54872